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I N D E X

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, Schedule B to the *Energy Competition Act, 1998*, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by **TORONTOHYDRO-ELECTRIC SYSTEM LIMITED** for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective June 1, 2012, May 1, 2013 and May 1, 2014.

APPLICATION for

2012, 2013 and 2014 IRM RATE ADJUSTMENTS and ICM RATE ADDERS

Title of Proceeding:	An Application by TORONTO HYDRO-ELECTRIC SYSTEM LIMITED for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective June 1, 2012, May 1, 2013 and May 1, 2014.
Applicant's Name:	Toronto Hydro-Electric System Limited ("THESL")
Applicant's Address:	14 Carlton Street Toronto, Ontario M5B 1K5
Applicant's Counsels:	**Fred D. Cass** **Amanda Klein**

Counsels' Contact Information:

Fred D. Cass
Partner
Aird & Berlis LLP
Brookfield Place
Suite 1800, Box 754
181 Bay Street
Toronto, Ontario M5J 2T9
fcass@airdberlis.com
tel: 416-865-7742
fax: 416-863-1515

Amanda Klein
Senior Regulatory Counsel
Toronto Hydro
14 Carlton Street
Toronto, Ontario M5B 1K5
regulatoryaffairs@torontohydro.com
aklein@torontohydro.com
tel: 416-542-2729
fax: 416-542-3024

INTRODUCTION

1. Toronto Hydro-Electric System Limited ("THESL") is the electricity distributor licensed by the Ontario Energy Board (the "OEB") to serve the City of Toronto. THESL makes this Application to the OEB for an Order or Orders approving the proposed distribution rates and charges set out in this Application as just and reasonable rates and charges pursuant to Section 78 of the *Ontario Energy Board Act, 1998*, Schedule B, S.O. 1998, c.15 and the OEB's Incentive Regulation Mechanism framework ("IRM").

2. Particulars of the relief sought by THESL in this Application are set out below. Further details of, including the detailed grounds for, such relief follows in the Manager's Summary (Tab 1) and Application evidence filed together with this Application.

3. Subject to the exceptions specified in the attached Manager's Summary, THESL has prepared this application in accordance with Chapter 3 of the Board's Filing Requirements for Transmission and Distribution Applications, dated June 22, 2011, the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, dated July 14, 2008, and the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, dated September 17, 2008 as well as other guidelines and directions from the Board, including the Board's January 5, 2012 Decision with Reasons and Order on the Preliminary Issue in EB-2011-0144 together with Board Decisions on other IRM applications that included a request for relief pursuant to the Board's Incremental Capital Module ("ICM").

4. The persons affected by this Application are the ratepayers of THESL's distribution business. It is impractical to set out their names and addresses because they are too numerous.

PROPOSED DISTRIBUTION RATES AND OTHER CHARGES

5. The Tariffs of Rates and Charges proposed in this Application are identified in Tab 3, Schedules B1 through B3 and the material being filed in support of this Application sets out THESL's approach to the determination of its proposed 2012-2014 distribution rates and charges.

6. A summary of monthly customer bill impacts for representative customers on a distribution and total bill basis is shown in Tab 3, Schedules C1 through C3.

EFFECTIVE DATE OF RATE ORDER(S)

7. As the schedule to address this Application will not permit 2012 rates to be implemented or effective as of May 1, 2012, THESL requests that the OEB issue an Order declaring the distribution rates and specific service charges effective as of May 31, 2012 to be interim as of June 1, 2012.

INTERIM RATES

8. With respect to the timing of the implementation of the 2012 rates, for the reasons set out in the Manager's Summary, THESL requests that:
   (a) the OEB approve rates being effective June 1, 2012, and implemented at a later date to be determined by the OEB;

(b) the OEB approve forgone revenue rates riders as its did in THESL's 2011 rates case (EB-2011-0144), to allow THESL an opportunity to recover the incremental revenue approved by the Board for the period between when rates became interim (June 1, 2012 on THESL's proposal) and when new rates are implemented (at the conclusion of this proceeding); and

(c) that the OEB permit THESL to recover the amounts corresponding to the approved 2012 ICM Projects over the period between rate implementation and April 30, 2014 (rather than April 30, 2013), so as to facilitate rate smoothing over the IRM period until rebasing.[1]

EVIDENCE, SUPPORTING MATERIAL AND METHOD OF HEARING

9. As noted above, this Application is supported by pre-filed written evidence, including the Manager's Summary.

10. THESL's evidence may be amended and/or supplemented in such time and manner that THESL may request and the OEB allows.

11. THESL proposes that this Application be heard orally. In the event that the OEB determines that it will proceed by way of an oral hearing, THESL will provide a list of witnesses and the relevant supporting information at that time.

[1] THESL makes this proposal on the basis of its understanding that upon rebasing, a final determination of the allowed revenue requirement attracted by the actual ICM expenditures will be made by the OEB, and that actual revenue received under the ICM rate adders will be reconciled to the ultimately approved amount, with any variance refunded to or collected from customers in the 2015 rate year.

AUTHORIZATION

12. This Application is authorized by Jean-Sebastien Couillard, Chief Financial Officer of THESL.

RELIEF SOUGHT

13. With this Application and pursuant to the IRM framework, THESL seeks express approval by the OEB of separate and successive revenue requirements and corresponding distinct electricity distribution rates and rate adders for each of the 2012, 2013, and 2014 rate years (the "Primary IRM Rates Relief").

14. In connection with the Primary IRM Rates Relief, and as set out in greater detail in the Manager's Summary, THESL seeks the following specific relief:

(a) on the basis that such an alternative could result in lower cumulative revenue requirements in the three proposed test years (i.e., rate mitigation), that the OEB determine whether it is appropriate to calculate the ICM materiality threshold in accordance with the existing formula *without* the 20% dead band factor, along with applying the half-year rule to each of the years 2012 through 2014;

(b) that the OEB recognize the OEB-approved, actual year-end ratebase for 2011 in the amount o*f appro*ximately $37.9 million, and approve a rate rider calculated to recover the revenue requirement related to the declining balance of these amounts for each year over the period until rebasing; and

(c) such further and other relief and THESL may request in the course of this proceeding, and the OEB allow.

15. In addition to the Primary IRM Rates Relief, THESL seeks the following further relief:

    (a) Price cap index adjustments to 2011 base distribution rates to produce corresponding 2012 distribution rates as described in the Manager's Summary;
    (b) adjusted Retail Transmission Service Rates, as set out in the Manager's Summary;
    (c) a rate rider to refund shared tax savings, as set out in the Manager's Summary;
    (d) a rate rider to dispose of the balance of the PILs Deferral Accounts 1562 (for the period October 1, 2001 to April 30, 2006) in accordance with the OEB's Decision an Order dated June 24, 2011, and the balance of Special Purpose Charge Account 1521, as set out in the Manager's Summary; and
    (e) such further and other relief and THESL may request in the course of this proceeding, and the OEB allow.

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL RATE

16. THESL seeks a decision of the OEB confirming that it has complied with the Final Order Regarding Suite Metering Issues dated April 26, 2012 in EB-2011-0144 (the "Suite Metering Order"), including a determination of the OEB that the name "Competitive Sector Multi-Unit Residential" rate class for the new Quadlogic class which will be incorporated into the proposed Tariff of Rates and Charges is approved.

Dated at Toronto, Ontario this 10th day of May, 2012:

All of which is respectfully submitted,

Fred D. Cass
Amanda Klein

DISCLAIMER

The information in these materials is based on information currently available to Toronto Hydro-Electric System Limited and its affiliates (together hereinafter referred to as “Toronto Hydro”), and is provided to the Ontario Energy Board (the “OEB”) for the purpose of presenting the OEB with Toronto Hydro’s electricity distribution rates application pursuant to the OEB’s Incentive Regulation Mechanism and Incremental Capital Module only (the “Application”). Toronto Hydro does not warrant the accuracy, reliability, completeness or timeliness of the information and undertakes no obligation to revise or update these materials, except as required for purposes of providing new information that represents a material change to the evidentiary record in the Application before the OEB. Toronto Hydro (including its directors, officers, employees, agents and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein.

These materials may also contain forward-looking information within the meaning of applicable securities laws in Canada (“Forward-Looking Information”). The purpose of the Forward-Looking Information is to provide Toronto Hydro’s expectations and future requirements for capital investment programs for 2012 through 2014, and may not be appropriate for other purposes. All Forward-Looking Information is given pursuant to the “safe harbour” provisions of applicable Canadian securities legislation. The words “anticipates”, “believes”, “budgets”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify Forward-Looking Information, although not all Forward-Looking Information contains these identifying words. The Forward-Looking Information reflects the current beliefs of, and is based on information currently available to, Toronto Hydro’s management. The Forward-Looking Information in these materials includes, but is not limited to, statements regarding Toronto Hydro’s future results of operations and performance, as well as expected nature, timing and cost of capital programs. The statements that make up the Forward-Looking Information are based on assumptions that include, but are not limited to, expected load and customer growth, externally driven plan relocation requests, estimated project costs, receipt of applicable regulatory approvals and requested rate orders. The Forward-Looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-Looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to, the rate of deterioration of Toronto Hydro’s assets, weather and environmental factors, unexpected increases or decreases in load and customer growth, differences between estimated and actual project costs, project delay due to factors beyond the control of Toronto Hydro’s management, and legislative, judicial or regulatory developments that could affect Toronto Hydro’s ability to meet the goals set out in this application. Toronto Hydro cautions that this list of factors is not exclusive. All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements, except as required by law, or by the OEB for the purposes of the Application. Toronto Hydro undertakes no obligation to revise or update any Forward-Looking Information as a result of new information, future events or otherwise after the date hereof, except as required by the OEB for the purposes of the Application.

MANAGER'S SUMMARY

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Introduction

THESL distributes electricity to City of Toronto consumers and submits this IRM/ICM Application to the Board in the context of the need to address essential and urgent electricity distribution infrastructure renewal. The ICM component of this Application represents a request for resources critical for THESL to bridge the gap to its next rebasing and Cost of Service application anticipated to occur in 2015. The specific projects THESL includes within the ICM reflect the minimum amount of infrastructure renewal THESL must undertake over the next three years to maintain current overall levels of system safety and reliability.

On August 26, 2011, THESL filed a cost of service application with the Board for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2012, May 1, 2013, and May 1, 2014 pursuant to section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended (the "COS Application").

On October 4, 2011, the Board issued Procedural Order No. 1 in respect of the COS Application, which ordered that the OEB would consider as a preliminary issue the question of whether THESL's application should be heard or whether it should be dismissed without a hearing (the "Preliminary Issue"), pursuant to the Board's 3GIRM policy with respect to hearing cost of service applications sooner than every four years (referred to by the Board as "early rebasing").

On January 5, 2012, the Board issued its Decision in respect of the Preliminary Issue. The OEB dismissed the COS Application, finding that THESL had not met the test set out by the OEB to justify hearing THESL's cost of service or rebasing application for 2012 through 2014 rates.

In its Decision the Board invited THESL to file a 2012 IRM application and to consider whether it would be appropriate to file an ICM as part of the application.[1]
Toronto Hydro-Electric System Limited ("THESL") applies now to the Ontario Energy Board ("OEB" or "Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998*, as amended,

[1] January 5, 2012 OEB Decision EB-2011-0144, page 24

for the approval of proposed distribution rates and charges under the Board's incentive regulation mechanism ("IRM") plan to be effective June 1, 2012, and implemented at a later date to be determined by the Board.

To the greatest extent possible, THESL has prepared this application in accordance with Chapter 3 of the Board's Filing Requirements for Transmission and Distribution Applications, dated June 22, 2011, as well as other guidelines and directions from the Board, including the Board's January 5, 2012 Decision with Reasons and Order on the Preliminary Issue in EB-2011-0144 together with Board Decisions on other ICM applications (collectively, the "IRM/ICM Material").

While THESL has sought to prepare its application in accordance with the IRM/ICM Material, it does, with respect to certain matters, either propose modified approaches to address distinctive needs, or new approaches in cases where the Board has not expressly pronounced on particular issues. All of these matters are addressed below under the Special Issues heading. The balance of the standard Manager's Summary follows that section. THESL's Current Tariff of Rates and Charges is presented at Tab 3, Schedule A. The Proposed adjustments to rates and charges and the resulting bill impacts are discussed in the sections below.

Special Issues

Overview

THESL provides the summary and outline below to assist the Board in assessing THESL's rationale regarding its approach to the Special Issues. THESL proposes that the Board consider a modified and/or new approach with respect to the following matters.

(a) Recognition in Rates of Approved 2011 Year-End Ratebase: THESL proposes that the Board recognize in 2012 distribution rates the Board-approved, actual year-end ratebase of 2011, which is materially larger than the average ratebase upon which 2011 rates were set;

(b) Three Year Period: THESL proposes ICM projects for a three-year period, severable into three successive one-year rate periods, each with its own ICM rate adder;

(c) Determination of Revenue Requirements: For the Board's consideration, THESL outlines an alternative to the standard treatment (also filed in evidence for purposes of comparison) of the calculation of the ICM threshold, together with the Board's practice of exempting certain ICM-approved capital expenditures from the application of the half year rule. The alternative approach provides for rate mitigation as it could result in lower cumulative revenue requirements over the three proposed years;

(d) Application of ICM Criteria: Having considered the IRM/ICM Material, THESL describes how its proposed ICM projects satisfy the criteria in THESL's circumstances;

(e) Interim Rates, Implementation of Rates, and True-up upon Rebasing: The schedule to address this Application will not permit 2012 rates to be implemented or effective as of May 1, 2012. Therefore THESL requests that the Board order that existing rates as of May 31, 2012 be declared interim as of June 1, 2012. Implementation of rates would occur at a future date as the Application is decided in due course. Upon rebasing, which is presently foreseen to occur in 2015, THESL understands that a final determination of the revenue requirement flowing from the ICM projects would be made by the Board and allowed revenues would be reconciled to revenues actually received, with any surplus or deficit returned to or recovered from customers. THESL proposes specifically that any revenue deficit arising from an effective date for 2012 rates after May 1, 2012 be included in the reconciliation upon rebasing.

Recognition in Rates of Approved 2011 Year-End Ratebase

THESL's Proposal

THESL proposes that the Board recognize in distribution rates the Board-approved, actual year-end ratebase of 2011, which is materially larger than the average ratebase upon which 2011 rates were set. As a result of the facts that 2011 rates were set on the basis of average ratebase, and that the IRM/PCI adjustment does not by itself recognize material increases in approved ratebase in place by the end of the rebasing year, a material deficiency stemming from the unrecognized ratebase is created in 2012 rates.

In order to remedy what would otherwise be an absence of cost recovery for Board-approved, actual expenditures incurred by THESL in 2011, THESL proposes that the Board approve a rate rider calculated to recover the revenue requirement related to the declining balance of the unrecognized amount for each year over the period until rebasing. The derivation of the foregone revenue requirement and associated rate riders for each year is provided at Appendix 1 to this Manager's Summary, and follows the standard convention for determining capital-related revenue requirement. This approach keeps both ratepayers and THESL whole with respect to these approved and actual expenditures.

Background and Rationale

The IRM-PCI-ICM ratemaking framework is applicable to THESL for the 2012 and subsequent rate years. Under that framework, distribution rates based on average ratebase for the rebasing year (2011 in THESL's case) are escalated for the subsequent years by the IRM-PCI factor. Additional rate adders may be approved by the Board with respect to *prospective* CAPEX in the subsequent year(s).

However, to the extent that year-end ratebase for the rebasing year materially exceeds the average ratebase used for the purpose of setting rebasing year rates, that difference between year-end and average ratebase is unrecognized under IRM and is uncompensated in rates for the subsequent years until the time of THESL's next rebasing. Further, at the time of that rebasing, only the depreciated balance remaining in net fixed assets is eligible for inclusion in ratebase.

In THESL's case, the Board-approved capital expenditures for the 2011 rebasing year were \$378.8 million, compared to Board-approved depreciation of \$138.8 million. Capital expenditures exceeding depreciation were therefore \$240 million on an approved basis.[2]

[2] THESL's actual capital expenditures in 2011 were \$445.5 million, but THESL requests this relief only with respect to the *Board-approved* capital expenditures.

By the operation of the half-year rule, this produces approved and actual, but unrecognized, ratebase in the amount of $120 million. Because this amount is unrecognized in ratebase and rates for 2012 through to the time of rebasing, THESL experiences an effective disallowance of $120 million of *approved* ratebase in rates for 2012, 2013 and 2014 under IRM (less corresponding depreciation over that period), even though those assets were installed and are being used to provide distribution services to customers at the end of 2011 (the "Approved-But-Forgone Ratebase").

THESL's foregone capital-related revenue requirement corresponding to this amount of Approved-But-Forgone Ratebase is approximately $12.6 million annually or $37.9 million over the IRM period. Upon rebasing and subject to acceptance by the Board, the depreciated amount corresponding to the Approved-But-Forgone ratebase would enter ratebase, but under that rebasing there would be no recovery of the foregone capital-related revenue requirement incurred during the interim PCI years.

In summary, the operation of the half-year rule in THESL's circumstances would result in a permanent loss of approximately $37.9 million dollars over the balance of the IRM term, unless remedied by the Board.

Three-Year Period

THESL's Proposal

The projects and annual amount of ICM funding sought in THESL's Application represent the level of capital funding that THESL requires in order to conduct a capital program that is expected to maintain the current levels of safety and reliability of its distribution system in a predictable and cost-effective manner. Predictability of THESL's capital program over a reasonable multi-year horizon is strongly conducive to the cost-effectiveness of that program.

In this application THESL proposes a period of three years overall, with each distinct year (2012 through 2014) being severable, and with each year having distinct distribution rates. THESL makes this proposal to strive to obtain reasonable certainty of funding and for reasons of regulatory efficiency. Reasonable certainty of funding is necessary for purposes of internal project planning, coordination of activities with external parties, and to obtain the most favourable commercial arrangements with external contractors.

To this end, THESL files with this application a separate standard ICM model and separate projects for each of the three years. As discussed in greater detail below, the specific projects set out in the application generally span the whole three year period and are generally constituted of individual jobs. While for each year, THESL proposes a slate of jobs comprising each project, the structure of THESL's capital plan is such that the character of the jobs and the projects remains constant over the aggregate three-year period.

THESL proposes that for analysis and ratemaking purposes, each year be distinct. Each year would have a separate set of rates and rate adders, and each year THESL would report to the Board as required on the progress and status of its ICM projects. However, as explained below, the timing of each job within the different projects may vary from the forecast, in order to allow for contingencies that arise when undertaking such a large and widespread construction program. For example, a specific job within a project could be delayed due to unforeseeable external factors such as changes in the infrastructure plans of the City or other utilities, or permitting issues. In such cases, THESL would be required to advance another job in order to manage and optimize work flow and avoid a situation of underutilized resources. THESL understands that delays and advancements in job timing would be assessed as to their impacts on the final approved revenue requirements stemming from the ICM projects upon true-up at the time of rebasing.

THESL proposes that each project be considered and treated as distinct, and will correspondingly strive to complete each project as proposed, as well as report as required on the status and progress for each project. THESL does not request the discretion to transfer resources between projects, but will need to manage the timing of jobs within projects as required to adjust to changing circumstances.

Background and Rationale

THESL's multi-year period proposal is driven by the goal of obtaining reasonable certainty and predictability with respect to funding THESL's necessary capital expenditures, and the benefit of regulatory efficiency.

THESL has only one source of funding for the capital-related costs of its capital expenditures, which is revenue from distribution rates. Income derived through other sources such as pole rentals and interest on deposits is returned to ratepayers directly by way of revenue offsets. While THESL has the ability to finance capital expenditures through borrowing and reinvestment of funds available through depreciation and retained earnings, that financing represents only the dedication of resources to investment in the business; it does not cover the cost of making the investment. The only source of funds available to THESL to cover the cost of the investment is revenue through distribution rates; because THESL is a regulated utility and returns other income to ratepayers through revenue offsets, there are no other resources THESL can draw upon to fund the costs of the investments it makes in the distribution system. Funding through ICM rate adders is therefore necessary to enable THESL to make net new investments in its distribution system.

Since THESL's needs in respect of capital funding are predictable, regulatory efficiency is served by consolidating THESL's applications for the three years as proposed. A three-year application affords the Board and stakeholders a longer-term view of THESL's capital needs and plans, and avoids the costly duplication of effort (for all parties) that would be entailed by THESL making three successive ICM applications during the interval prior to rebasing.

Furthermore, reasonable certainty and predictability of funding is necessary for purposes of conducting an efficient and cost-effective capital program such as THESL's, which requires internal project planning, coordination of activities with external parties, and commercial arrangements with external contractors. THESL's evidence in rate applications since 2007 has provided detailed documentation of its long term infrastructure renewal program. That program has been ongoing for several years with Board approval, and THESL believes that it must continue, at least at a pace that prevents further worsening of the condition of its distribution system. This undertaking is necessarily a multi-year program that requires significant planning and coordination well in advance of the execution of specific jobs.

Planning and coordination is required with municipal and provincial authorities in charge of infrastructure such as roads and highways and the permitting of work on THESL assets within road allowances; with other utilities for the purposes of synchronizing construction schedules; with external contractors for the purposes of entering into contracts and commercial arrangements on the most favourable terms; and for the purpose of managing THESL's internal workforce to ensure that adequate resources with the proper skills and training are in place to execute the planned work.

Although different jobs clearly have different timelines from commencement to completion, the overall process must be a continuous one in order to effectively and efficiently marshal the required resources and maintain coordination with other utilities and the municipal authorities. In addition, the infrastructure renewal work undertaken by THESL requires significant advance notice and consultation with the residents in the areas affected by THESL's work. THESL undertakes this consultation intensively, well in advance of the commencement of construction, specifically for the purpose of minimizing disruption to residents and obtaining input to the design of the various projects.

It is not possible for THESL to conduct this overall process effectively and efficiently without a long term planning horizon of at least 24 to 36 months. Without assurance of funding, THESL cannot enter into stable arrangements with contractors or plan for the stability of its own workforce; it cannot plan customer engagement activities around its construction program; and it cannot obtain permits for or coordinate its construction programs with the municipality or other utilities.

It is also essential for the purpose of obtaining the most favourable terms from external contractors that THESL be able to offer those contractors the prospect of a predictable and preferably steady volume of work. As is the case for contractors in any sector of the economy, THESL's contractors cannot realize the lowest unit costs if labour and other resources are not fully deployed, because the fixed costs of those resources are not spread over the maximum possible number of units of work.

The condition of having a stable volume of work is independent of the level of that work, provided that a sufficiently material volume of work is available to attract contractor commitment. While THESL has existing contracts with external contractors, those contracts do not oblige those contractors to accept the work that THESL has available. If the volume of work that THESL can offer is unpredictable, there is the prospect that its contractors would decline THESL's work in favour of other opportunities where the work is predictable and offers a better prospect of recovering the contractor's fixed costs. In that event THESL would be driven to short-term contracts for specific jobs at significantly higher prices.

Multi-year approval of THESL's capital plans offers the benefit of a predictable volume of work, which can be executed cost-effectively, without presupposing a specific level of work.

The costs of the ICM projects proposed in this Application are estimated based on the existing contracts between THESL and its contractors. However, the availability of this pricing may be contingent on both the level and predictability of the work that THESL can offer to those contractors.

Determination of Revenue Requirements and Rate Mitigation

THESL's Proposal

In this application, THESL follows the standard Board-approved approach for the calculation of ICM revenue requirements and rate adders. THESL also offers for the consideration of the Board an alternative to the standard treatment of the calculation of the ICM threshold, and the practice of exempting ICM-approved capital expenditures from the application of the half-year rule, except in the year immediately preceding rebasing. THESL observes that this alternative approach provides for rate mitigation as it could result in lower cumulative revenue requirements over the three proposed years. Specifically, THESL proposes the following modification, consisting of two parts:

1) The ICM threshold would be calculated in accordance with the existing formula *without* the 20% dead band factor, and would thus represent approved depreciation in the rebasing year adjusted by growth and the PCI.

2) The ICM rate adders would be calculated for each year based on the *average* incremental ICM investment in that year (i.e., the approved ICM expenditure above the modified ICM threshold), calculated using the half year rule.

Background and Rationale

Under the Board's standard ICM model, THESL understands that funding is available for approved projects over the calculated materiality threshold. In years that do not immediately precede rebasing, the half-year rule is used in calculating the ICM adder so as to avoid creating a structural deficiency.

The formula for the materiality threshold determination is given in the EB-2007-0673 Supplemental Report of the Board (the "Supplemental Report"). The formula contains a dead band factor of 20% over and above the calculation of the level of CAPEX supported by the PCI-adjusted rates.

In THESL's case, the values of the equation parameters, together with the current figure of 2.0% for inflation, produce a threshold percentage value of 124.62% and a threshold dollar value of $172,989,464. Excluding the 20% factor, the threshold value (after accounting for load growth and the PCI adjustment) would be $145,226,308. This is higher than 2011 approved depreciation of $138,815,781 by $6,410,527 due to the value for the PCI of 0.68% combined with a negative value for the growth parameter, derived from the Board's ICM model. The dead band value, defined as the difference between the threshold amount with and without the 20% factor, is $27,763,156. The derivation of these figures is given at Appendix 2 to this Manager's Summary.

By construction, the dead band amount represents the amount of CAPEX that THESL must undertake, in each year, without compensation in rates under the IRM-ICM framework, until rebasing. Assuming an approximate value of 10% to represent the foregone capital-related revenue requirement in each year, and that the half-year rule would apply to deadband CAPEX in all years, over the three-year PCI period THESL would forego approximately $12.1 million in /U
revenue requirement. The derivation of this amount is given in the revised Appendix 3 to this /U
Manager's Summary. /U

Using the assumptions noted above and in the explanatory notes to the revised Appendix 3, /U
THESL has calculated that if the approved ICM amount under the Standard Approach for 2012 /U
and 2013 combined exceeds $228.2 million, then the standard ICM model would produce a /U
windfall (i.e., surplus revenue requirement), which THESL does not seek and would regard as an unintended outcome. The derivation of this amount is given in the revised Appendix 3 to this Manager's Summary. /U

The Board may wish to consider modifying the standard ICM model in THESL's case to dispense with the 20% threshold and incorporate the half-year rule for all years. This would allow for the regular capital-related revenue requirements for approved ICM spending, in excess of the level that can be supported through the growth- and PCI-adjusted level of depreciation.

This modification would keep both ratepayers and THESL whole with respect to the approved ICM investments and would preclude windfall amounts from accruing to either party. Given the ICM amounts at issue, the windfall amounts are potentially substantial. The modified approach would be applicable regardless of the Board's determination of the number of years it will approve under this application.

To demonstrate the significant differences in the ICM rate adders that would result from the modified approach relative to the standard approach, THESL has filed the standard ICM models at Tab 4, Schedules E1 to E3, together with the calculated adders from the alternative approach. A summary of the comparative ICM revenue requirements and corresponding rate adders for the Residential and General Service <50kW classes appears below in Table 1. In total across the three years, the proposed revenue requirement is lower by $27.7 million under the alternative approach. THESL considers this amount to be significant from the perspective of rate mitigation.

Table 1: Comparative Revenue Requirements and Rate Adders

Revenue Requirements $ Millions	**2012**	**2013**	**2014**	**Total**
Standard Methodology	$ 26.80	$ 36.00	$ 13.50	$ 76.30
Alternative Methodology	$ 14.60	$ 19.30	$ 14.70	$ 48.60
Difference	$ 12.20	$ 16.70	$ (1.20)	$ 27.70
Residential Rate Adders				
Standard Methodology				
Fixed Portion ($/30 days)	$ 0.92	$ 1.23	$ 0.46	
Variable Portion ($/kWh)	$ 0.00077	$ 0.00103	$ 0.00039	
Alternative Methodology				
Fixed Portion ($/30 days)	$ 0.50	$ 0.66	$ 0.50	
Variable Portion ($/kWh)	$ 0.00042	$ 0.00055	$ 0.00042	
Difference				
Fixed Portion ($/30 days)	$ 0.42	$ 0.57	$ (0.04)	
Variable Portion ($/kWh)	$ 0.00035	$ 0.00048	$ (0.00003)	
GS < 50 kW Rate Adders				
Standard Methodology				
Fixed Portion ($/30 days)	$ 1.22	$ 1.64	$ 0.61	
Variable Portion ($/kWh)	$ 0.00115	$ 0.00154	$ 0.00058	
Alternative Methodology				
Fixed Portion ($/30 days)	$ 0.67	$ 0.88	$ 0.67	
Variable Portion ($/kWh)	$ 0.00063	$ 0.00082	$ 0.00063	
Difference				
Fixed Portion ($/30 days)	$ 0.55	$ 0.76	$ (0.06)	
Variable Portion ($/kWh)	$ 0.00052	$ 0.00072	$ (0.00005)	

There are two further issues that relate to the multi-year features of THESL's ICM application. First, THESL is aware that most of 2012 may have elapsed by the time that the Board issues its

Decision in this proceeding. The date for rate implementation is unknown at this time. In these circumstances, THESL suggests that the Board may wish to consider permitting THESL to recover the approved 2012 ICM adder amounts over the period from 2012 rate implementation until April 30, 2014, or in the alternative merging the 2012 and 2013 years into a single period consisting of 24 months, ending December 31, 2013. THESL remains prepared to report to the Board on the progress of its capital program as of the end of 2012 when that information becomes available in 2013.

Second, the Board's Renewed Regulatory Framework for Electricity ("RRFE") is underway and may produce a revised framework early enough to be available for 2014 applications. While the implementation of the new framework remains to be determined, it is THESL's view that nothing in this application would constrain the adoption of a new framework for THESL, even prior to 2015. The Board's requirements for reporting and true-up reconciliation would remain applicable to THESL's ICM capital programs, and these ensure that no undue variances are borne by ratepayers or THESL.

Application of ICM Criteria

As noted by the Board in the January 5, 2012 Decision with Reasons and Order on the Preliminary Issue in EB-2011-0144, the Board's thinking in respect of the ICM eligibility criteria has evolved. THESL has carefully reviewed the ICM Material and has sought to address and meet the Board's criteria for consideration and acceptability of ICM projects. THESL addresses each of these criteria below, beginning with those cited specifically by the Board in reference to a potential ICM application by THESL.

Discrete

THESL's ICM portfolio consists of ten discrete programs, some of which are divided into segments and each of which is composed of numerous jobs to be completed across the three year period. For purposes of severability the programs, segments, and jobs are grouped into yearly categories. The ICM portfolio structure for each year is illustrated in Table 2 below.

Table 2: ICM Portfolio Structure

Projects	Segments
Underground Infrastructure and Cable	Underground Infrastructure
	Paper Insulated Lead Covered Cable - Piece Outs and Leakers
	Handwell Replacement
Overhead Infrastructure and Equipment	Overhead Infrastructure
	Box Construction
	Rear Lot Construction
	Polymer SMD-20 Switches
	Scadamate R1 Switches
Network Infrastructure and Equipment	Network Vault and Roofs
	Fibertop Network Units
	Automatic Transfer Switches and Reverse Power Breakers
Station Infrastructure and Equipment	Stations Power Transformers
	Stations Switchgear - Municipal and Transformer Stations
	Stations Circuit Breakers
	Stations Control and Communication Systems
	Downtown Station Load Transfers
Bremner Transformer Station	Bremner Transformer Station
Hydro One Capital Contributions	Hydro One Capital Contributions
Feeder Automation	Feeder Automation
Metering	Metering
Plant Relocations	Externally-Initiated Plant Relocations and Expansions
Grid Solutions	Grid Solutions

Each project may contain jobs that are geographically dispersed across Toronto, but the projects are nevertheless unified by one or more defining characteristics pertaining to the nature of the work to be done. For example, the Overhead Infrastructure and Equipment Project addresses the need to restore overhead distribution, and the jobs constituting this project are unified by the fact that all of them address various forms of overhead plant in need of remediation.

Detailed descriptions of the scope and nature of the jobs contained within each project are provided at Tab 4, Schedules B1 to B22. Each project is clearly identifiable, coherent, and distinguishable from other projects, and THESL's evidence contains detailed descriptions of the work to be undertaken within each project (i.e., the jobs).

For certain projects such as Bremner Transformer Station, expected completion dates are set out in the corresponding evidence. For projects and segments that are composed of many discrete jobs, such as Overhead Infrastructure, THESL estimates that for each year, two-thirds of the jobs would be complete within that year, with the remaining third completed the following year.

Material and Incremental

THESL's proposed capital expenditures for each of the three years clearly exceed the ICM materiality threshold, regardless of whether that threshold is calculated using the standard methodology or the modified methodology proposed by THESL. The capital expenditure amounts requested have a significant impact on the operations of THESL directly, first of all with respect to the quality and reliability of service provided to customers by THESL, and secondly with respect to staffing levels and staff deployment, together with all the support and ancillary activities associated with THESL's capital program (e.g., supplies, vehicles and equipment, hiring, financial accounting, etc.)

Furthermore, the level of THESL's capital program will have direct effects on the requirements for access to short and long term capital markets.

The proposed ICM projects and associated jobs are also new and incremental to the rebasing year (2011) revenue requirement. However, many of the projects are effectively continuations of programs that have been in existence for some time, such as the replacement of direct-buried underground feeders. In those cases, the ICM projects address geographical areas and infrastructure that have not been previously renewed.

Need

The evidence describing each project addresses in detail the need for the project and why the project is essential and non-discretionary. Every project addresses a well-defined need that must be met in the short term, i.e., over the three-year period. Generally, projects are essential and non-discretionary on the basis that they are required by one or more of the following:

(a) Statute, code, provincial policy, or equivalent external requirement (including connection of customers, restoration of power, and externally initiated plant relocations);

(b) Considerations of safety for the public and for workers operating in, on, or around equipment;

(c) Existing or imminent reliability degradations;

(d) Existing or imminent capacity shortages;

(e) A material increase in cost (beyond the time value of money), if the project is necessary but undertaken at a later time. For additional clarity and by way of example, assume a large brown field area is to be redeveloped in phases over 10 years and will ultimately be served by four underground 27.6 kV feeders. To provide service to the first phase, only one feeder is necessary, and the current construction cost to install the concrete duct for one feeder is less than the current cost to install the ducts for four feeders. However, the present value of the total cost to install four ducts, one at a time for four separate feeders, is substantially larger than the current cost to install four ducts at one time.[3] In this light the project to install the ductwork for all four feeders at one time becomes non-discretionary because it would be imprudent to install the ductwork separately for each feeder.

Not all projects are non-discretionary based on all of these considerations, but every project is needed and non-discretionary based on at least one of these criteria.

Where applicable, jobs within a given project are prioritized among years on the basis of urgency, with consideration given to other factors such as control of total costs and operational feasibility. For example, where a priority ranking based strictly on the urgency of reliability improvements would dictate a fragmented and more costly approach to the renewal of

[3] THESL would also recognize other benefits associated with undertaking the work in a single project, rather than four separate projects, such as minimizing disruption to customers and the public.

underground infrastructure in a given neighbourhood, jobs would be grouped and sequenced to achieve an orderly approach to infrastructure renewal in that neighbourhood.

In addition, further evidence describing THESL's Feeder Investment Model is set out at Appendix 4 to this Manager's Summary.

THESL has also retained external consultants to provide independent analysis and opinion on:

(a) THESL's Business Cases for its proposed ICM projects; and,
(b) THESL's Asset Management (AM) methodologies and practices and its conformity with accepted industry practices. In some case, THESL's AM practices are leading in the industry.

The reports of those consultants are filed at Tab 4, Schedules D1 to D6.

Safety Considerations Pertinent to Need

For a number of projects for which THESL seeks ICM funding, need is supported by consideration of worker and/or public safety. For some projects, the current residual safety risk of certain equipment is a major driver for why the proposed project is needed.

THESL's safety practices follow the hierarchy of controls for safety hazards from the OHSAS (Occupational Health and Safety Advisory Services) 18001 standard:

1) Elimination of hazard;
2) Substitution of hazard with something less hazardous;
3) Engineering controls;
4) Systems that increase awareness of potential hazards;
5) Administrative controls (training, procedures, instructions); and
6) Personal protective equipment.

The higher a control is on the list, the more effective it is considered to be in reducing or eliminating a safety risk.

It is within this context that THESL has focused efforts in the last several years to further enhance its worker and public safety program. Such efforts have included restructuring its safety organization by adding skilled staff and introducing a rigorous safety management program.

THESL's practices for keeping workers and the public safe have become all the more important in the presence of aging and obsolete equipment. As noted above, while items 2 through 6 in the hierarchy of controls listed above are important to any safety program where workers, and in some cases the public, are exposed to electricity distribution equipment, the best control is always the first: elimination of the hazard itself.

Where THESL's distribution equipment is not functioning at an acceptable current standard, it may be the case that a residual safety risk exists. In such a case, this residual safety risk exists no matter how effective THESL's other controls are, as the risk cannot be eliminated except by replacement of the equipment. Accordingly, having equipment which functions acceptably is critical to THESL ensuring workplace, and public, safety.[4]

Prudent

For each project, evidence of the prudence of the chosen approach, relative to alternatives (to the extent they are available) is presented. Prudence is defined as the achievement of or approach to the lowest reasonable life cycle cost consistent with all other constraints, including for example safety of equipment, compliance with standards including accepted standards of good utility practice, public acceptability, and the reliability and adequacy of the distribution

[4] With respect to safety-related terminology, the terms 'catastrophic failure', 'fail catastrophically', and related forms, are used throughout the business cases presented in this Application. These terms refer to a mode of failure of an electrical distribution component in which incidental damage to other equipment and/or injury to a person occurs or could occur, in addition to the loss of the electrical distribution function of the component itself. Explosive arc flashes, fires, falling debris, and structural collapse are examples of catastrophic failure. Catastrophic failure is distinguished from failure-by-design and simple failure modes in which a component, such as a fuse, performs according to design to interrupt the flow of electricity or otherwise ceases to perform its electrical distribution function without creating actual or potential damage or injury to adjacent equipment or persons in the vicinity.

system. While it is not possible in all cases to precisely quantify the costs and characteristics all of the possible alternative approaches to solving a given problem, THESL has endeavoured, to the greatest extent possible, to provide quantitative and/or qualitative evidence for the major alternatives.

Unusual

Several of the ICM projects involve jobs that must be regularly undertaken by a mature urban utility. It is a requirement for utilities to replace obsolete and failing plant at the end of its life. In this connection, the Board found at page 18 of its Decision on the Kingston Hydro Corporation application (EB-2011-0178) that projects similar to those being proposed by THESL "are consistent with the purpose of the ICM, and that it is appropriate to evaluate the four projects using the incremental capital investment eligibility criteria".

The circumstances surrounding the scale and timing of THESL's capital program are unusual because the proportion of total assets in need of replacement is high. The fact that this needs to occur over a relatively short period when compared against the complete lifecycle of the equipment is in large part due to the fact that much of the equipment was installed in response to a boom in development in the 1960s and 1970s.

An example of this unusual asset replacement pattern that will become evident over the next few years involves smart meters as they come up for replacement. Because smart meters were installed in large numbers over a short interval, their replacement pattern will exhibit the same characteristic: a sharp peak in activity, rather than a smooth and uniform pattern of activity.

The Board has before it, in this application and in previous applications, a substantial body of evidence demonstrating that much of THESL's distribution assets either have already, or will soon, reach end of life. This is a function in large part of the timing and pattern of asset installation. The assets of a utility exhibit demographic features much in the same way as the population does. While birth and death of individuals in a population is not unusual from a global perspective, the 'baby boom' phenomenon is unusual and is analogous to the demographic features of THESL's infrastructure.

Interim Rates, Implementation of Rates, And True-Up Upon Rebasing

As a result of the events leading to THESL's IRM/ICM application for 2012 rates, the timing of the Application does not permit rates to be implemented for May 1, 2012 or for existing rates to be declared interim as of that date. Therefore THESL requests that the Board issue an Order making rates in effect as of May 31, 2012 interim as of June 1, 2012.

Such an order would not presuppose in any way the outcome of this proceeding, nor would it in any way bind the Board. Rather, it would provide the Board with additional flexibility with respect to the implementation of rates resulting from the Board's ultimate decision with respect to THESL's application, and it would afford THESL a reasonable opportunity to recover the costs approved by the Board for the 2012 rate year.

Given the uncertainty about when the proceeding will conclude, THESL proposes that the Board continue with the practice it followed in 2011 for THESL's rates, under which rates were implemented upon the conclusion of the proceeding but were effective as of an earlier date when rates became interim. In that case, the Board approved 'foregone revenue' rate riders which were designed to permit THESL an opportunity to recover the incremental revenue approved by the Board for the period between when rates became interim and when new rates were implemented.

For the purpose of avoiding a large terminal revenue variance with respect to the 2012 ICM rate adder, THESL proposes that the Board approve 'foregone ICM rate adder revenue' rate riders corresponding to the period between when existing rates become interim (i.e., June 1 under THESL's request) and the date of implementation of 2012 rates.

THESL also proposes that the Board evaluate the option of permitting THESL to recover the amounts corresponding to the approved 2012 ICM programs over the period between rate implementation and April 30, 2014, rather than April 30, 2013. This would be conducive to rate smoothing over the IRM period until rebasing. (At present, all the ICM rate adders presented in this Application are calculated based on the assumption of 12-month loads and customer numbers.) Under this approach, and assuming for the purpose of illustration an implementation date of November 1, 2012, the duration of the respective rate adders over the ICM period is illustrated below in Figure 1.

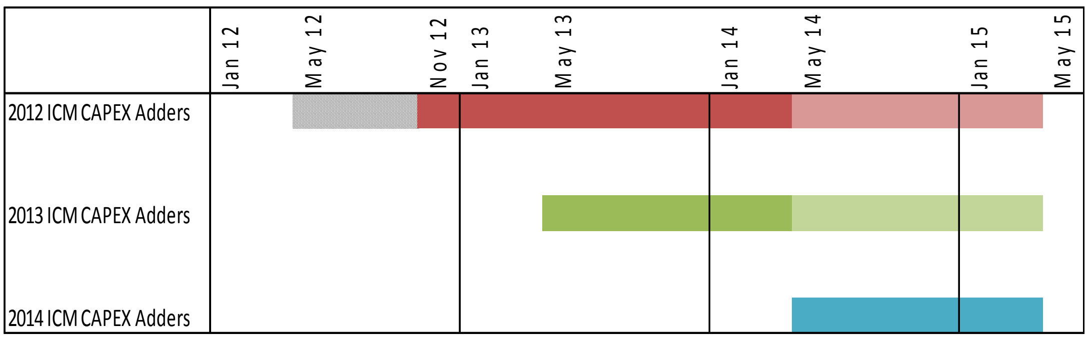


Figure 1: Duration of Rate Adders

THESL makes these proposals on the basis of its understanding that upon rebasing, a final determination of the allowed revenue requirement attracted by the actual ICM expenditures will be made by the Board, and that actual revenue received under the ICM rate adders will be reconciled to the ultimately approved amount, with any variance refunded to or collected from customers in the 2015 rate year. The reconciliation between allowed and actual revenue would be conducted regardless of the amount of the variance (unless it is immaterial) and regardless of the date and manner in which rates were implemented throughout the period. THESL also understands that the true-up process will account for the actual timing of jobs, and that a variance in job timing would not, by itself, cause any job to become ineligible for inclusion in the calculation of the actual revenue requirements associated with the ICM. On this basis both ratepayers and THESL would be kept whole with respect to the approved ICM expenditures actually made by THESL, and THESL would not be subject to a revenue deficit as a result of the ICM rate adders being implemented later than May 1, 2012.

THESL cannot undertake the obligation to make the corresponding capital expenditures without the opportunity to recover the associated costs through approved ICM rate adders.

Comparison Between THESL's Cost Of Service And IRM/ICM Applications

Capital Projects Not Included in This Application

THESL's former long-term capital plan, which was directed to stable and programmatic renewal of distribution and general assets, and which was substantially approved by the Board in THESL's last three rate cases over the previous four years, cannot be conducted within the IRM/ICM framework due to the restriction on capital spending that exists within that framework given the non-discretionary criterion.

The capital plan outlined in this ICM application has been significantly curtailed relative to the early rebasing application that THESL presented to the Board under file EB-2011-0144. The total capital requested by year under each application framework is shown in Table 3 below.

Table 3: Total Capital Requests – Rebasing vs ICM ($ millions)

	2012	2013	2014	Total
REBASING	$ 590.0	$ 615.0	$ 640.0	$ 1,845.0
ICM	$ 448.7	$ 534.5	$ 439.5	$ 1,422.7
Difference	($141.3)	($80.5)	($200.5)	$ (422.3)

THESL does not plan to execute projects such as Paper Insulated Lead Covered Cable Replacement, Asbestos Insulated Lead Covered Cable Replacement, Stations Infrastructure, Nomenclature, Grounding Compliance, Electric Vehicles and Modernization Initiatives in the next three years. In addition, for continuing project areas such as underground infrastructure, THESL now proposes further reductions in capital spending for the purposes of the submitted ICM projects relative to previous proposals.

Projects of this kind were proposed by THESL in the EB-2011-0144 proceeding. THESL believes that the projects proposed there were prudent, necessary for the long term management and sustainment of the distribution system, and in the public interest.

THESL nevertheless accepts the facts that the Board dismissed that application and that THESL's current proposals must meet the ICM criteria. THESL believes that the projects proposed in this Application are essential to the maintenance of system health and functionality. While there have been some changes relative to the work proposed in EB-2011-0144 which reflect the passage of time, the ICM projects now proposed substantially represent the subset of work previously proposed that THESL considers to be essential over the immediate term.

Furthermore, there has been a significant change in the composition of the proposed spending. By definition, only non-discretionary capital spending is eligible for inclusion in an ICM application. That criterion holds THESL to a bare sustainment capital program during the pre-rebasing period, such that projects that are necessary in the near term but are not urgently required during the three year period are excluded. Projects that provide for stable and predictable renewal of distribution and general plant are thus deferred to THESL's rebasing application anticipated for 2015. As such, THESL's proposals are intended and necessary to maintain existing levels of reliability.

The ICM screening mechanism has had the effect of increasing the proportion of proposed capital expenditures devoted to distribution plant in contrast to general plant. This is set out in Table 4 below.

Table 4: Distribution Plant Percentages of CAPEX – Rebasing vs ICM

REBASING		2012		2013		2014
Total Capital	$	590.0	$	615.0	$	640.0
Less Fleet, Facilities, Other	$	(38.6)	$	(37.8)	$	(39.4)
Less IT	$	(42.1)	$	(48.2)	$	(53.1)
Distribution Plant	$	509.3	$	529.0	$	547.5
Distribution Plant % of Total		86.3%		86.0%		85.5%
ICM						
Total Capital	$	448.7	$	534.5	$	439.5
Less Fleet, Facilities, Other	$	(9.4)	$	(10.6)	$	(8.0)
Less IT	$	(15.0)	$	(15.0)	$	(15.0)
Distribution Plant	$	424.3	$	508.9	$	416.5
Distribution Plant % of Total		94.6%		95.2%		94.8%

Implementation of New Suite Meter Rate

In its Corrected Decision and Order on Suite Metering Issues dated March 9, 2012 in EB-2010-0142, the Board determined that a separate rate class should be created for multi-residential customers that at the present time are served utilizing Quadlogic technology. In its Decision, the Board directed THESL "to implement the new rate in conjunction with its rate setting process for 2012" and "file a revised cost allocation model and related rates and other material, reflecting the Board's findings in this Decision".

In its Final Order Regarding Suite Metering Issues dated April 26, 2012, the Board directed THESL to:

(a) incorporate the rates of $17.00 for the Quadlogic class fixed charge and $0.02565 for the Quadlogic class variable charge, and $18.25 for the remaining Residential class fixed charge and $0.01507 for the remaining Residential class variable charge into its 2012 rate application in conformity with the Corrected Suite Metering Decision and subsequent Board directives arising from this application;

(b) propose a formal name for the new Quadlogic class and text for the definition of this class to be incorporated into the proposed Tariff of Rates and Charges filed as part of its 2012 rate application;

(c) provide any similar necessary related changes to the Residential class to appropriately reflect the creation of the new Quadlogic class in conformity with the Corrected Suite Metering Decision; and

(d) provide an explanation as to why the reduction in the Residential Variable charge did not occur based on the directions of the Board in the DDO, or file a new cost allocation model run to reflect the DDO of the Board and produce the expected reduction in the Residential Variable charge as part of its 2012 rate setting process.

With respect to (a) above, THESL has included these rates in the Board-approved rate generator model. THESL has interpreted the Board's direction to indicate that the rates specified in the Corrected Decision are to be escalated by the 2012 PCI adjustment, in parallel with all of THESL's other base distribution rates.

With respect to (b) above, THESL proposes the name "Competitive Sector Multi-Unit Residential" for the rate class currently termed "Quadlogic". Applicability of the rate would be to units in multi-unit residential buildings where metering is provided using technology substantially similar to that employed by competitive sector sub-metering providers. This description will be incorporated into the proposed Tariff of Rates and Charges filed as part of THESL's 2012 rate application.

With respect to (c) above, THESL proposes to add a qualification to the applicability of the standard Residential rate stating that the standard rate is not applicable to service otherwise subject to the Competitive Sector Multi-Unit Residential rate.

With respect to (d) above, the Board's directions to remove the Quadlogic meter customers from the total Residential meter count in the Sheet I7.1 – Meter Capital in the Cost Allocation Model allocation had the effect of increasing costs to the Quadlogic class by approximately

$43,000, which was then removed from the revenue responsibility of the Residential class. This reduction of $43,000 is small enough that it does not impact the variable rate of the Residential class rounded to the 5th decimal place.

This is demonstrated by the following figures in Table 5, which are taken from the table titled "Revenue and Revenue to Cost Ratios" on page 7 of the respective Draft Rate Orders filed in the EB-2010-0142 proceeding.

Table 5: Reconciliation of Residential Class Variable Rate

Residential Class Variable Rate	March 19th DRO	April 19th DRO	Difference
Distribution Revenue (A)	$73,665,828	$73,622,882	-$42,946
kWh Billing Units (B)	4,886,977,489	4,886,977,489	
Rate (A/B)	$0.015073	$0.015065	
Rounded Rate	$0.01507	$0.01507	

Proposed Adjustments to Rates and Charges

The proposed Schedule of Rates and Tariffs is presented at Tab 3, Schedule B. The Schedule reflects the following changes from the previous Schedule approved by the Board in EB-2011-0142:

(a) 2012 price cap adjustment
(b) adjusted Retail Transmission Service Rates
(c) rate rider to refund shared tax savings
(d) rate rider for disposition of account balances in accounts 1521 Special Purpose Charge and account 1562 PILS Deferral Account
(e) rate adder for incremental capital projects

The details of the proposed adjustments are discussed below.

2012 Price Cap Adjustment

THESL has calculated a price cap adjustment of 0.68% This calculation is reflected in Sheet 17 of the 2012 IRM3 Rate Generator model (the "model") filed at Tab 3, Schedule C based on the a price escalator of 2.0%, less a productivity factor of 0.72%, and less a stretch factor of 0.60%.

Adjusted Retail Transmission Service Rates

Like other electric distributors, THESL is charged transmission service rates by Hydro One Networks Incorporated ("HONI"), which are passed through to THESL's distribution customers through Retail Transmission Service Rates ("RTSRs"). THESL has calculated adjustments to its current RTSRs in the RTSR Work form filed at Tab 3, Schedule D. The calculations of the adjusted RTSR network service rates and RTSR connection service rates are presented in Sheets 11 and 12 of the RTSR Work form. These rates are inputs in Sheets 15 and 16 of the IRM Rate Generator model.

THESL understands the model will be updated with any changes to HONI's transmission service rates.

Rate Rider to Refund Shared Tax Savings

THESL has calculated the 2012 shared tax savings amount at $1,243,901, 50% of which or $621,950 will be shared with rate payers. The shared amount is allocated to customer rate classes on the basis of the most recent Board-approved base year distribution revenue through a volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates. The savings amount is calculated using the Shared Tax Savings Workform filed at Tab 3, Schedule D. The rate riders are inputs in Sheet 14 of the model.

Rate Rider for Deferral and Variance Account Balance Disposition

THESL completed the Deferral and Variance Account worksheets included in the IRM Rate Generator model. The total balance of Group 1 accounts, which includes Accounts 1580, 1584, 1586 and 1588 but excludes Accounts 1521 and 1562, is $4,776,133, as shown in Sheet 10 of the model. The amount does not exceed the materiality threshold of $.001/kWh defined in the Electricity Distributors' Deferral and Variance Account Review ("EDDVAR") report and therefore does not warrant disposition at this time.

THESL, however, is proposing the disposition of the balances in Account 1562 – Deferred PILs and Account 1521 – Special Purpose Charge ("SPC") Assessment Variance.

THESL's proposal to dispose of the balance in Account 1562 – Deferred PILs is discussed in greater detail at Tab 5.

The Board authorized Account 1521, SPC Assessment Variance Account in accordance with Section 8 of Ontario Regulation 66/10 (Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs) (the "SPC Regulation"). THESL has recorded in the account the difference between amounts remitted to the Minister of Finance related to THESL's SPC Assessment and the amounts recovered from customers through the SPC over the May 1, 2010 to December 31, 2011 period. THESL proposes to recover from customers the debit balance in the account as of December 31, 2011 of $574,577, which includes carrying charges up to April 30, 2012.

In accordance with the Board's expectation in its EB-2008-0381 Decision dated June 24, 2011, THESL proposes the final disposition of the balance of Account 1562. A detailed discussion of this proposal is provided at Tabs 5.

The rate rider to dispose of the account balances of the 1562 and 1521 accounts is shown in the 2012 IRM3 Rate Generator, at Sheet 12.

Naming of Competitive Multi-Unit Residential class and Unmetered Scattered Load class in OEB models

Due to the fact that the OEB models used to generate the various class rates and rate riders are locked, THESL was required to use the naming conventions that were provided for in the models for certain classes. Thus, the Competitive Multi-Unit Residential class is identified as Residential Urban in the models. Similarly, since THESL's rate for the Unmetered Scattered Load class includes three components (Customer, Connection, and Variable charges), THESL has identified the USL Connection rate as Sentinel Lighting in the IRM Rate Generator model. In the ICM and Shared Tax Savings models, THESL has used a second USL class to capture the Connection portion of the rates.

LRAM Application

Based on estimates of the actual CDM achieved over the 2008 to 2010 period, compared with the amounts included in THESL's load forecasts for the respective years, THESL had calculated an LRAM amount of $3.6M (inclusive of carrying charges). However, in view of the Board's recent rulings on similar applications, THESL has determined that it will not apply for clearance of that amount.

Bill Impacts

A summary of monthly bills for representative customers on a distribution and total bill basis is shown in Tab 3, Section C. The schedules show the individual and combined impacts of the distribution component, rate riders, other components (e.g., transmission and network charges), and total bill, for a representative level of consumption within each rate class.

APPENDIX 1 TO MANAGER'S SUMMARY

($ millions)

CapEx Approved 2011		378.8		
Funded through Depreciation		-138.8		
Fixed Assets Impact		240.0		
Closing Rate Base in 2011		120.0		
Opening Rate Base in 2012		120.0		
Rate Base	2012	2013	2014	Total
Opening Rate Base	120.0	116.3	112.5	
Depreciation for the year	-3.8	-3.8	-3.8	
Closing Balance	116.3	112.5	108.8	
Average Balance	118.1	114.4	110.6	
Revenue Requirement				
Depreciation	3.8	3.8	3.8	11.3
Cost of capital (6.94%)				
Interest (5.18% x 60%)	3.6	3.5	3.4	10.5
Return on Equity (9.58% x 40%)	4.5	4.4	4.2	13.1
PILs	1.0	1.0	0.9	3.0
Total Revenue Requirement	**12.9**	**12.6**	**12.3**	**37.9**
PILs Calculation				
Target Net Income	4.5	4.4	4.2	13.1
Add: Depreciation	3.8	3.8	3.8	11.3
Less: CCA	-5.4	-5.4	-5.4	-16.1
Income for PILs purposes	2.9	2.8	2.6	8.3
PILs	0.8	0.7	0.7	2.2
Gross-up PILs	1.0	1.0	0.9	3.0
Assumptions				
Depreciation vs CCA ratio	1.43	1.43	1.43	
Average life of Assets	32 years	32 years	32 years	
Tax rate	26.40%	26.40%	26.40%	

2011 Lost Revenue - 2012 Rate Rider Calculation

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kVA F = $N * C	Total Revenue by Rate Class G = D + E + F	
Residential	24.92%	14.00%	0.00%	$ 3,222,880.79	$ 1,810,855.34	$ -	$ 5,033,736.14	
Competitive Sector Multi-Unit Residential	0.39%	0.49%	0.00%	$ 50,176.06	$ 62,937.53	$ -	$ 113,113.60	
General Service Less Than 50 kW	3.65%	9.14%	0.00%	$ 471,728.16	$ 1,181,975.84	$ -	$ 1,653,704.01	
General Service 50 to 999 kW	1.06%	0.00%	28.65%	$ 137,098.93	$ -	$ 3,705,927.28	$ 3,843,026.21	
General Service 1,000 to 4,999 kW	0.80%	0.00%	8.96%	$ 104,109.36	$ -	$ 1,158,347.07	$ 1,262,456.43	
Large Use	0.32%	0.00%	4.50%	$ 41,729.90	$ -	$ 582,088.24	$ 623,818.14	
Street Lighting	0.48%	0.00%	1.76%	$ 62,437.84	$ -	$ 227,443.69	$ 289,881.53	
Unmetered Scattered Load	0.00%	0.65%	0.00%	$ 163.33	$ 83,926.51	$ -	$ 84,089.84	
Unmetered Scattered Load	0.24%	0.00%	0.00%	$ 31,031.18	$ -	$ -	$ 31,031.18	
				$ 4,121,355.55	$ 3,139,695.23	$ 5,673,806.28	$ 12,934,857.07	(N)

Rate Class	Billed Customers or Connections H	Billed kWh I	Billed kVA J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kVA Rate Rider M = F / J	Service Charge Rate Rider (DOS)	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kVA Rate Rider (DOS)
Residential	598,508	4,886,977,489	0	$0.448738	$0.000371		**$0.44**	**$0.00037**	
Competitive Sector Multi-Unit Residential	24,898	99,791,184	0	$0.167939	$0.000631		**$0.17**	**$0.00063**	
General Service Less Than 50 kW	65,792	2,139,318,076	0	$0.597498	$0.000553		**$0.59**	**$0.00055**	
General Service 50 to 999 kW	13,067	10,116,374,153	26,935,191	$0.874363	$0.000000	$0.137587	**$0.86**		**$0.1357**
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	$16.878949	$0.000000	$0.109411	**$16.65**		**$0.1079**
Large Use	47	2,376,778,323	4,993,733	$73.989183	$0.000000	$0.116564	**$72.98**		**$0.1150**
Street Lighting	162,777	110,165,016	322,023	$0.031965	$0.000000	$0.706297	**$0.03**		**$0.6966**
Unmetered Scattered Load	1,130	56,231,585	0	$0.012048	$0.001493		**$0.01**	**$0.00149**	
Unmetered Scattered Load	21,729	0	0	$0.119008			**$0.12**		

2011 Lost Revenue - 2013 Rate Rider Calculation

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kVA F = $N * C	Total Revenue by Rate Class G = D + E + F	
Residential	24.92%	14.00%	0.00%	$ 3,145,193.29	$ 1,767,204.70	$ -	$ 4,912,397.99	
Competitive Sector Multi-Unit Residential	0.39%	0.49%	0.00%	$ 48,966.57	$ 61,420.42	$ -	$ 110,386.99	
General Service Less Than 50 kW	3.65%	9.14%	0.00%	$ 460,357.16	$ 1,153,484.33	$ -	$ 1,613,841.49	
General Service 50 to 999 kW	1.06%	0.00%	28.65%	$ 133,794.16	$ -	$ 3,616,595.95	$ 3,750,390.11	
General Service 1,000 to 4,999 kW	0.80%	0.00%	8.96%	$ 101,599.80	$ -	$ 1,130,425.13	$ 1,232,024.93	
Large Use	0.32%	0.00%	4.50%	$ 40,724.00	$ -	$ 568,057.01	$ 608,781.01	
Street Lighting	0.48%	0.00%	1.76%	$ 60,932.78	$ -	$ 221,961.16	$ 282,893.94	
Unmetered Scattered Load	0.00%	0.65%	0.00%	$ 159.39	$ 81,903.47	$ -	$ 82,062.86	
Unmetered Scattered Load	0.24%	0.00%	0.00%	$ 30,283.17	$ -	$ -	$ 30,283.17	
				$ 4,022,010.33	$ 3,064,012.92	$ 5,537,039.25	$ 12,623,062.50	(N)

Approved 2011 Load Forecast

Rate Class	Billed Customers or Connections H	Billed kWh I	Billed kVA J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kVA Rate Rider M = F / J	Service Charge Rate Rider (DOS)	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kVA Rate Rider (DOS)
Residential	598,508	4,886,977,489	0	$0.437921	$0.000362		**$0.43**	**$0.00036**	
Competitive Sector Multi-Unit Residential	24,898	99,791,184	0	$0.163891	$0.000615		**$0.16**	**$0.00062**	
General Service Less Than 50 kW	65,792	2,139,318,076	0	$0.583095	$0.000539		**$0.58**	**$0.00054**	
General Service 50 to 999 kW	13,067	############	26,935,191	$0.853287	$0.000000	$0.134270	**$0.84**		**$0.1324**
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	$16.472082	$0.000000	$0.106774	**$16.25**		**$0.1053**
Large Use	47	2,376,778,323	4,993,733	$72.205675	$0.000000	$0.113754	**$71.22**		**$0.1122**
Street Lighting	162,777	110,165,016	322,023	$0.031194	$0.000000	$0.689271	**$0.03**		**$0.6798**
Unmetered Scattered Load	1,130	56,231,585	0	$0.011758	$0.001457		**$0.01**	**$0.00146**	
Unmetered Scattered Load	21,729	0	0	$0.116139			**$0.11**		

2011 Lost Revenue - 2014 Rate Rider Calculation

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kVA F = $N * C	Total Revenue by Rate Class G = D + E + F	
Residential	24.92%	14.00%	0.00%	$ 3,067,505.79	$ 1,723,554.05	$ -	$ 4,791,059.85	
Competitive Sector Multi-Unit Residential	0.39%	0.49%	0.00%	$ 47,757.08	$ 59,903.32	$ -	$ 107,660.39	
General Service Less Than 50 kW	3.65%	9.14%	0.00%	$ 448,986.16	$ 1,124,992.82	$ -	$ 1,573,978.98	
General Service 50 to 999 kW	1.06%	0.00%	28.65%	$ 130,489.39	$ -	$ 3,527,264.62	$ 3,657,754.02	
General Service 1,000 to 4,999 kW	0.80%	0.00%	8.96%	$ 99,090.25	$ -	$ 1,102,503.19	$ 1,201,593.44	
Large Use	0.32%	0.00%	4.50%	$ 39,718.10	$ -	$ 554,025.78	$ 593,743.88	
Street Lighting	0.48%	0.00%	1.76%	$ 59,427.72	$ -	$ 216,478.63	$ 275,906.35	
Unmetered Scattered Load	0.00%	0.65%	0.00%	$ 155.45	$ 79,880.42	$ -	$ 80,035.87	
Unmetered Scattered Load	0.24%	0.00%	0.00%	$ 29,535.16	$ -	$ -	$ 29,535.16	
				$ 3,922,665.11	$ 2,988,330.60	$ 5,400,272.22	$ 12,311,267.93	(N)

Rate Class	Approved 2011 Load Forecast								
	Billed Customers or Connections H	Billed kWh I	Billed kVA J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kVA Rate Rider M = F / J	Service Charge Rate Rider (DOS)	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kVA Rate Rider (DOS)
Residential	598,508	4,886,977,489	0	$0.427105	$0.000353		**$0.42**	**$0.00035**	
Competitive Sector Multi-Unit Residential	24,898	99,791,184	0	$0.159842	$0.000600		**$0.16**	**$0.00060**	
General Service Less Than 50 kW	65,792	2,139,318,076	0	$0.568693	$0.000526		**$0.56**	**$0.00053**	
General Service 50 to 999 kW	13,067	10,116,374,153	26,935,191	$0.832210	$0.000000	$0.130954	**$0.82**		**$0.1292**
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	$16.065215	$0.000000	$0.104136	**$15.85**		**$0.1027**
Large Use	47	2,376,778,323	4,993,733	$70.422166	$0.000000	$0.110944	**$69.46**		**$0.1094**
Street Lighting	162,777	110,165,016	322,023	$0.030424	$0.000000	$0.672246	**$0.03**		**$0.6630**
Unmetered Scattered Load	1,130	56,231,585	0	$0.011467	$0.001421		**$0.01**	**$0.00142**	
Unmetered Scattered Load	21,729	0	0	$0.113270			**$0.11**		

APPENDIX 2 To Manager's Summary

Derivation of ICM Threshold Amounts

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Ratebase (approved 2011)	$	2,298,227,281
Depreciation (approved 2011)	$	138,815,781
Load Growth Revenue Change	decimal	-0.004
Inflation	decimal	0.02
Productivity	decimal	0.0072
Stretch Factor	decimal	0.006
PCI	decimal	0.0068
TwentyPercentFactor	decimal	0.2
Threshold %		124.62%
Threshold Amount	$	172,989,464
Deadband Amount		27,763,156
Threshold Amount w/o Deadband		145,226,308
Actual 2010 Distribution Rev	$	530,130,457
Approved 2011 Distribution Revenue	$	528,018,642
Load Growth Revenue Change	decimal	-0.004

Threshold Amount w/o 20% factor	$	145,226,308
Increase over 2011 approved dep'n	$	6,410,527

REVISED Appendix 3 to Manager's Summary
Derivation of Foregone Revenue From Deadband CAPEX

($ millions)

FOREGONE REVENUE FROM DEADBAND CAPEX SUBJECT TO HYR	2012	2013	2014	Total
2012 CAPEX				
Opening Incremental Ratebase	0.000	27.347	26.514	
Deadband CAPEX in 2012 - opening	0.000			
Deadband CAPEX in 2012 - closing	27.763			
Average Deadband CAPEX in 2012	13.882			
Depreciation @ 3%	0.416	0.833	0.833	
Closing Incremental Ratebase	27.347	26.514	25.681	
Average Incremental Ratebase	13.673	26.930	26.097	
Revenue Requirement on Average Incremental Ratebase @ 10%	1.367	2.693	2.610	6.670
2013 CAPEX				
Opening Incremental Ratebase		0.000	27.347	
Deadband CAPEX in 2013 - opening		0.000		
Deadband CAPEX in 2013 - closing		27.763		
Average Deadband CAPEX in 2013		13.882		
Depreciation @ 3%		0.416	0.833	
Closing Incremental Ratebase		27.347	26.514	
Average Incremental Ratebase		13.673	26.930	
Revenue Requirement on Average Incremental Ratebase @ 10%		1.367	2.693	4.060
2014 CAPEX				
Opening Incremental Ratebase			0.000	
Deadband CAPEX in 2014 - opening			0.000	
Deadband CAPEX in 2014 - closing			27.763	
Average Deadband CAPEX in 2014			13.882	
Depreciation @ 3%			0.416	
Closing Incremental Ratebase			27.347	
Average Incremental Ratebase			13.673	
Revenue Requirement on Average Incremental Ratebase @ 10%			1.367	1.367
Total Foregone Revenue Requirement 2012-2014 - WITH HYR				**12.098**

REVISED Appendix 3 to Manager's Summary
Comparative Revenue Requirements Analysis
Equal Revenue Requirements
($ millions)

REVENUE REQUIREMENT CALCULATED USING STANDARD APPROACH	**2012**	**2013**	**2014**	**Total**
2012 CAPEX				
Opening Incremental Ratebase	0.000	110.676	107.253	
Above-Threshold CAPEX in 2012 - opening	0.000			
Above-Threshold CAPEX in 2012 - closing (solution variable)	114.099			
Depreciation @ 3%	3.423	3.423	3.423	
Closing Incremental Ratebase	110.676	107.253	103.830	
Average Incremental Ratebase	112.388	108.965	105.542	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2012 CAPEX	11.239	10.896	10.554	32.689
2013 CAPEX				
Opening Incremental Ratebase		0.000	110.676	
Above-Threshold CAPEX in 2013 - opening		0.000		
Above-Threshold CAPEX in 2013 - closing (solution variable)		114.099		
Depreciation @ 3%		3.423	3.320	
Closing Incremental Ratebase		110.676	107.356	
Average Incremental Ratebase		112.388	109.016	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2013 CAPEX		11.239	10.902	22.140
TOTAL REVENUE REQUIREMENT CALCULATED USING STANDARD APPROACH				**54.830**
REVENUE REQUIREMENT CALCULATED USING ALTERNATE APPROACH				
Deadband CAPEX	27.763			
2012 CAPEX				
Opening Incremental Ratebase	0.000	139.734	135.479	
Above-Threshold CAPEX in 2012 - opening	0.000			
Above-Threshold CAPEX including deadband in 2012 - closing (solution variable)	141.862			
Average Above-Threshold CAPEX in 2012	70.931			
Depreciation @ 3%	2.128	4.256	4.256	
Closing Incremental Ratebase	139.734	135.479	131.223	
Average Incremental Ratebase	69.867	137.606	133.351	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2012 CAPEX	6.987	13.761	13.335	34.082
2013 CAPEX				
Opening Incremental Ratebase		0.000	139.734	
Above-Threshold CAPEX in 2013 - opening		0.000		
Above-Threshold CAPEX including deadband in 2013 - closing (solution variable)		141.862		
Average Above-Threshold CAPEX in 2013		70.931		
Depreciation @ 3%		2.128	4.256	
Closing Incremental Ratebase		139.734	135.479	
Average Incremental Ratebase		69.867	137.606	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2013 CAPEX		6.987	13.761	20.747
TOTAL REVENUE REQUIREMENT CALCULATED USING ALTERNATE APPROACH				**54.830**
DIFFERENCE IN REVENUE REQUIREMENTS - STANDARD vs ALTERNATE				**0.000**
APPROVED LEVEL OF 2012 + 2013 CAPITAL ABOVE THRESHOLD - STANDARD APPROACH				**228.198**
APPROVED LEVEL OF 2012 + 2013 CAPITAL ABOVE THRESHOLD - ALTERNATE APPROACH				**283.725**

REVISED Appendix 3 to Manager's Summary
Comparative Revenue Requirements Analysis
Lower Standard Approach Revenue Requirement
($ millions)

REVENUE REQUIREMENT CALCULATED USING STANDARD APPROACH	**2012**	**2013**	**2014**	**Total**
2012 CAPEX				
Opening Incremental Ratebase	0.000	48.500	47.000	
Above-Threshold CAPEX in 2012 - opening	0.000			
Above-Threshold CAPEX in 2012 - closing (solution variable)	50.000			
Depreciation @ 3%	1.500	1.500	1.500	
Closing Incremental Ratebase	48.500	47.000	45.500	
Average Incremental Ratebase	49.250	47.750	46.250	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2012 CAPEX	4.925	4.775	4.625	14.325
2013 CAPEX				
Opening Incremental Ratebase		0.000	48.500	
Above-Threshold CAPEX in 2013 - opening		0.000		
Above-Threshold CAPEX in 2013 - closing (solution variable)		50.000		
Depreciation @ 3%		1.500	1.455	
Closing Incremental Ratebase		48.500	47.045	
Average Incremental Ratebase		49.250	47.773	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2013 CAPEX		4.925	4.777	9.702
TOTAL REVENUE REQUIREMENT CALCULATED USING STANDARD APPROACH				**24.027**
REVENUE REQUIREMENT CALCULATED USING ALTERNATE APPROACH				
Deadband CAPEX	27.763			
2012 CAPEX				
Opening Incremental Ratebase	0.000	76.597	74.264	
Above-Threshold CAPEX in 2012 - opening	0.000			
Above-Threshold CAPEX including deadband in 2012 - closing (solution variable)	77.763			
Average Above-Threshold CAPEX in 2012	38.882			
Depreciation @ 3%	1.166	2.333	2.333	
Closing Incremental Ratebase	76.597	74.264	71.931	
Average Incremental Ratebase	38.298	75.430	73.097	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2012 CAPEX	3.830	7.543	7.310	18.683
2013 CAPEX				
Opening Incremental Ratebase		0.000	76.597	
Above-Threshold CAPEX in 2013 - opening		0.000		
Above-Threshold CAPEX including deadband in 2013 - closing (solution variable)		77.763		
Average Above-Threshold CAPEX in 2013		38.882		
Depreciation @ 3%		1.166	2.333	
Closing Incremental Ratebase		76.597	74.264	
Average Incremental Ratebase		38.298	75.430	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2013 CAPEX		3.830	7.543	11.373
TOTAL REVENUE REQUIREMENT CALCULATED USING ALTERNATE APPROACH				**30.055**
DIFFERENCE IN REVENUE REQUIREMENTS - STANDARD vs ALTERNATE				**-6.028**
APPROVED LEVEL OF 2012 + 2013 CAPITAL ABOVE THRESHOLD - STANDARD APPROACH				**100.000**
APPROVED LEVEL OF 2012 + 2013 CAPITAL ABOVE THRESHOLD - ALTERNATE APPROACH				**155.526**

REVISED Appendix 3 to Manager's Summary
Comparative Revenue Requirements Analysis
Higher Standard Approach Revenue Requirement
($ millions)

REVENUE REQUIREMENT CALCULATED USING STANDARD APPROACH	**2012**	**2013**	**2014**	**Total**
2012 CAPEX				
Opening Incremental Ratebase	0.000	194.000	188.000	
Above-Threshold CAPEX in 2012 - opening	0.000			
Above-Threshold CAPEX in 2012 - closing (solution variable)	200.000			
Depreciation @ 3%	6.000	6.000	6.000	
Closing Incremental Ratebase	194.000	188.000	182.000	
Average Incremental Ratebase	197.000	191.000	185.000	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2012 CAPEX	19.700	19.100	18.500	57.300
2013 CAPEX				
Opening Incremental Ratebase		0.000	194.000	
Above-Threshold CAPEX in 2013 - opening		0.000		
Above-Threshold CAPEX in 2013 - closing (solution variable)		200.000		
Depreciation @ 3%		6.000	5.820	
Closing Incremental Ratebase		194.000	188.180	
Average Incremental Ratebase		197.000	191.090	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2013 CAPEX		19.700	19.109	38.809
TOTAL REVENUE REQUIREMENT CALCULATED USING STANDARD APPROACH				**96.109**
REVENUE REQUIREMENT CALCULATED USING ALTERNATE APPROACH				
Deadband CAPEX	27.763			
2012 CAPEX				
Opening Incremental Ratebase	0.000	224.347	217.514	
Above-Threshold CAPEX in 2012 - opening	0.000			
Above-Threshold CAPEX including deadband in 2012 - closing (solution variable)	227.763			
Average Above-Threshold CAPEX in 2012	113.882			
Depreciation @ 3%	3.416	6.833	6.833	
Closing Incremental Ratebase	224.347	217.514	210.681	
Average Incremental Ratebase	112.173	220.930	214.097	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2012 CAPEX	11.217	22.093	21.410	54.720
2013 CAPEX				
Opening Incremental Ratebase		0.000	224.347	
Above-Threshold CAPEX in 2013 - opening		0.000		
Above-Threshold CAPEX including deadband in 2013 - closing (solution variable)		227.763		
Average Above-Threshold CAPEX in 2013		113.882		
Depreciation @ 3%		3.416	6.833	
Closing Incremental Ratebase		224.347	217.514	
Average Incremental Ratebase		112.173	220.930	
Revenue Requirement on Average Incremental Ratebase @ 10% - 2013 CAPEX		11.217	22.093	33.310
TOTAL REVENUE REQUIREMENT CALCULATED USING ALTERNATE APPROACH				**88.030**
DIFFERENCE IN REVENUE REQUIREMENTS - STANDARD vs ALTERNATE				**8.079**
APPROVED LEVEL OF 2012 + 2013 CAPITAL ABOVE THRESHOLD - STANDARD APPROACH				**400.000**
APPROVED LEVEL OF 2012 + 2013 CAPITAL ABOVE THRESHOLD - ALTERNATE APPROACH				**455.526**

Notes to Revised Appendix 3 to Managers Summary

THESL has revised Appendix 3 to the Managers Summary to improve the clarity and accuracy of the analysis of the comparative revenue requirements produced by both the Standard Approach and the Alternate Approach, at various levels of approved capital expenditures above the respective Thresholds under each approach. In summary, the revised analysis calculates the respective revenue requirements under each Approach to determine at what levels of capital expenditure the revenue requirements are equal, and what the differential revenue requirements are at arbitrarily lower and higher levels of capital expenditure. The revised analysis shows that the requirements are equal when the combined capital expenditures for 2012 and 2013 are $228.2 million under the Standard Approach excluding Deadband capital, and $283.7 million including Deadband capital under the Alternate Approach.

At levels of Standard Approach CAPEX less than $228.2 million for 2012 and 2013 combined, the effect of the exclusion of Deadband CAPEX outweighs the effect of applying the half year rule to the 2012 and 2013 CAPEX under the Alternate Approach, and the Standard Approach produces a lower revenue requirement. Conversely, at higher levels of CAPEX, the opposite result occurs, with the Standard Approach producing a higher revenue requirement. At an arbitrarily selected level of $400 million of Standard Approach CAPEX for 2012 and 2013 combined, the Standard Approach revenue requirement is $8.1 million higher. The CAPEX levels under each Approach are always different by the Deadband amount of $27.8 million per year.

The revenue requirements derived in the revised analysis are indicative and are based on certain assumptions which may differ from an exact calculation performed when all relevant information is available. These assumptions include:

a) A depreciation rate of 3%.

b) A capital-related revenue requirement attraction percentage of 10%.

c) Constant figures for the Deadband amount and the respective Thresholds under each approach. These will vary in 2013 and 2014 depending on then-current values of parameters involved in the Threshold calculation.

d) CAPEX being equally divided between 2012 and 2013.

e) Year end incremental ratebase resulting from both 2012 and 2013 CAPEX being recognized for rate setting purposes in subsequent years.

The derivation of the foregone revenue due to the exclusion of the Deadband CAPEX is marginally revised to reflect greater precision in the Deadband amount and straight line depreciation.

THESL'S FEEDER INVESTMENT MODEL AND ITS USE IN DEVELOPING ICM PROJECTS

Introduction

This document explains THESL's Feeder Investment Model (FIM) and discusses how THESL has used it in evaluating the proposed ICM projects presented in this application. The FIM is a risk-based model designed to identify the economically optimal replacement time for aging assets. At the highest level, the model works by balancing the cost associated with the increasing risk of failure as assets age and their condition degrades ("risk cost") against the benefit of delaying the capital spending required for replacement by extending service life as long as possible.

In situations involving "like-for-like" or "in-kind" replacement, where THESL is replacing defective or obsolete equipment with current standard equipment (e.g., polymer SMD-20 switches), the model compares the "risk cost" of replacement in 2012 against the present value of the "risk cost" associated with replacement in 2015. The difference between the 2015 and 2012 risk cost figures is the value of undertaking the replacement now. The year 2015 was chosen to represent the timing of THESL's next cost of service filing.

In situations where THESL proposes to replace one type of asset with another type (e.g., rear lot conversion), a somewhat different comparison is made. These "non-in-kind" projects are evaluated based on the difference in 'cost of ownership' between the existing state and new state. Initially, the existing state only considers the risk cost because for an existing asset capital costs are sunk until the asset reaches optimal replacement age, after which, both capital and risk costs are considered. These are compared to the capital and risk costs associated with the replacement asset over a 100-year period. The difference in the present value of the cost of ownership between the existing and new states is the benefit of undertaking the replacement.

Operation of the FIM

Figure 1 below is an illustrative example of the FIM optimization process. The Annualized Risk Cost represents the probability weighted cost of asset failure, which is shown as the red line increasing over time. As explained more fully below, these costs include the cost of replacing the asset on a reactive basis and the customer cost associated with the asset failing given its function and location on the distribution system and its typical failure mode. The Annualized Capital Cost is the cost of ownership of a particular type of asset calculated by annualizing its acquisition and carrying cost across over its projected life. This is shown by the blue line which decreases over time as the asset depreciates. The combination of the annualized risk and capital cost curves is the grey Annualized Life Cycle Cost curve, the minimum point of which is the Equivalent Annual Cost (EAC), which shown by the red circle.

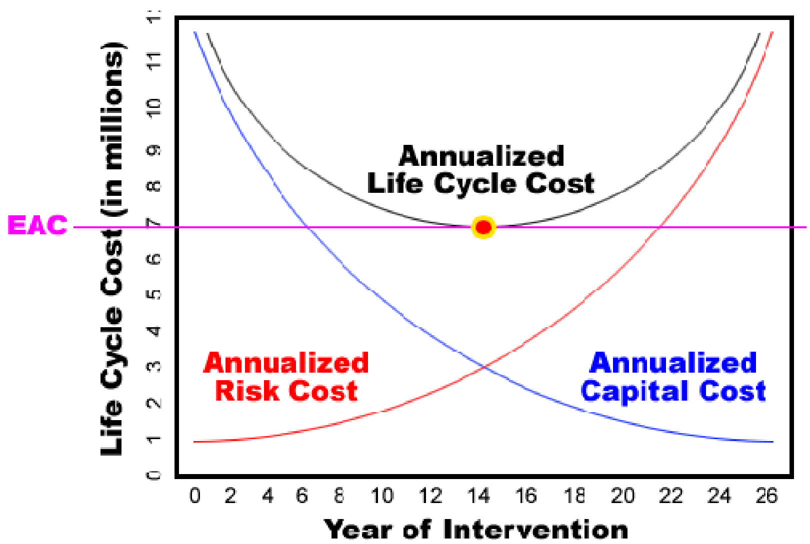


Figure 1: Illustrative Example of Asset Life Cycle Optimization

EAC represents the minimum annualized cost of owning a new asset, based on replacing it at the optimal time. It captures the cost of acquiring a new asset, installing and maintaining it, and the probability weighted cost of its failure.

As shown in Figure 2, the EAC can be used to determine the Optimal Intervention Time for an existing asset. This is accomplished by plotting the EAC for a new asset on the Risk Cost curve for an existing asset of the same type. The point at which the Risk Cost of the existing asset equals the EAC (minimum annualized cost of a new asset) represents the optimal time for replacement as shown by the green line in Figure 2.

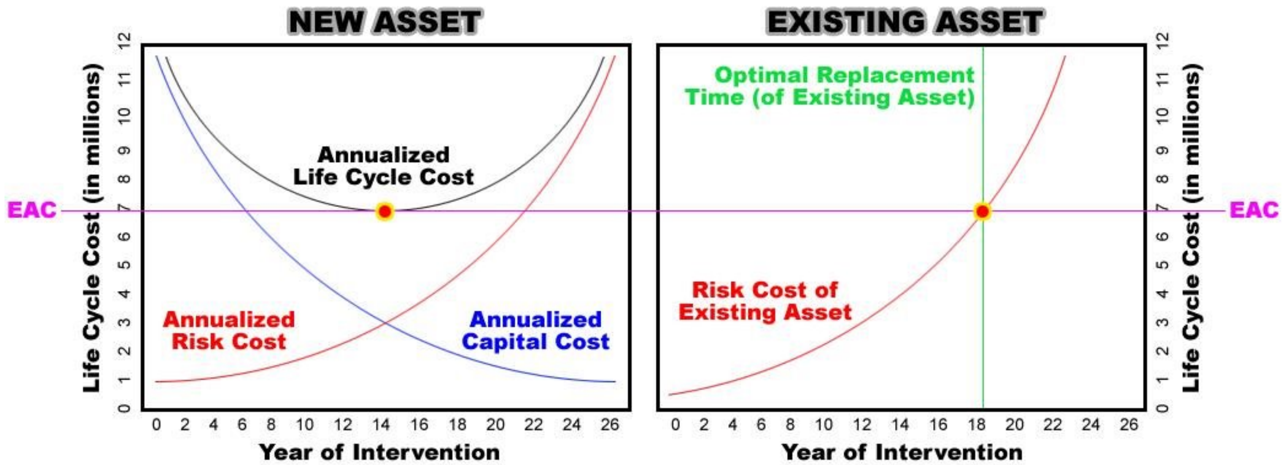


Figure 2: Illustrative Example of Optimal Intervention Time (Existing Assets)

At a more detailed level, the FIM approach compares the costs that THESL and its customers will experience if an existing asset fails weighted by the probability of failure[1] (Risk Cost) against the annualized cost of replacing that asset with a new one. These asset-related failure costs include both the cost of replacing the failed asset and the costs that customers will incur as a result of the failure. The cost of replacing the failed asset includes the cost of acquiring and installing the new asset and any additional costs necessitated by the fact it failed in operation and must be replaced on a reactive basis.

The cost of failure to customers is based on the consequences of failure for each asset. Consequence costs depend on the magnitude and duration of customer interruptions associated with a particular asset. The FIM bases the magnitude of an outage on the peak load interrupted, which is calculated based on the location of the asset and the configuration of the distribution system at its location. This is good proxy for the magnitude of customer impacts because it accounts for the combined load of different customer classes that are served by the asset and the fact that more outages occur during peak periods when assets are heavily loaded. The duration of the outage is estimated based on the following parameters for each asset class:

[1] The probability of an asset's failure at any point in time is based on its age and condition. This information is derived as described in the Asset Condition Assessment. Age-and-condition parameters are translated into a probability of failure using a Hazard Rate Distribution Function, which represents the conditional probability of failure for any given asset in the population that has survived to that time.

(i) The type of failed asset.
(ii) The type of asset failure mode.
(iii) The manner in which the asset is configured within the distribution system.
(iv) The process by which the system is restored to its former (pre-outage) state (e.g., repair or replacement of asset)

The risk costs also include non-asset related failure costs. These are the costs of failures that derive from causes other than the asset itself. These causes include weather, vegetation, animal interference and human interference.

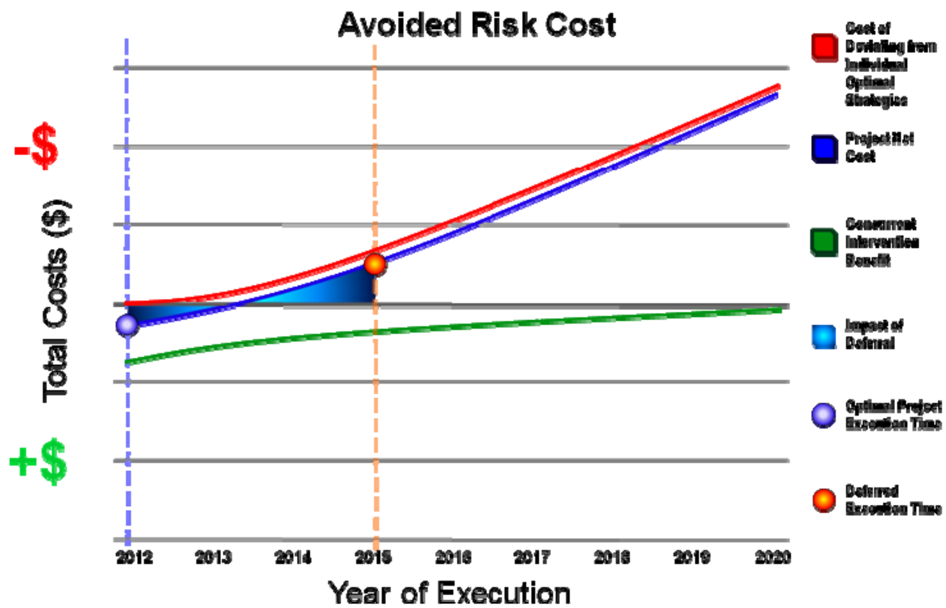
The FIM can be used to evaluate either replacement of a single asset or replacement of asset combinations involving various asset types present on a feeder. This latter “job-based” approach allows engineering staff to evaluate the grouping of assets within a job, in terms of the comparative benefits of replacement. When several assets are replaced together in a job, there are additional costs and savings.

The additional costs derive from the fact that not every asset being replaced will be at its optimal replacement time. Assets may be before, at, or beyond their optimal replacement time. Thus some assets will have sacrificed economic life because they are replaced before their optimal replacement time, while others will have incurred excess risk cost because they are replaced after their optimal replacement time. The cumulative sacrificed life and excess risk of the assets included in the job becomes a cost against the project.

The benefits from replacing assets together derive from the savings realized from concurrent replacement. These “concurrent intervention” benefits are the savings from replacing multiple assets in a single job. They include factors such as improved equipment utilization, reduced set-up time, improved transportation of crew and material, and reduced road blockage costs. These benefits must be weighed against the total costs (cumulative asset excess risk and sacrificed life values) in order to produce an overall project net cost calculation.

The cumulative sacrificed life and excess risk of the assets being replaced shown by the red curve in Figure 3. The concurrent intervention benefits are illustrated by the green curve in

Figure 3. Taking the sum of the costs (cumulative asset excess risk and sacrificed life values) and benefits, year by year, provides the Net Project Benefit for the Job-Based Approach, illustrated by the blue curve in Figure 3.



Avoided Estimated Risk Cost

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

<u>FIM Metrics Explained</u>

The **Avoided Risk Cost** output shows the benefit of executing this work immediately, as opposed to deferring this work until 2015. The avoided risk costs cover both types of risk cost (asset-related and non-asset-related). As previously mentioned, asset-related risks include the direct and indirect costs associated with asset replacement and resulting outage impacts to customers, while non-asset risks include the risks associated with factors other than the assets themselves such as weather, vegetation, animal contact and human-related events. The avoided risk costs cover both types of risk cost explained above (asset-related and non-asset-related). This measure is used for the Underground Infrastructure, Overhead Infrastructure, SCADA-Mate R1, SMD-20 projects, and all project covering stations facilities and equipment.

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.

When this avoided cost is calculated as a positive value, it means that estimated risk costs for the 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 anticipated risks.

The **Cost of Ownership** represents the net present value, taken over a century, of the various costs associated with owning the assets in question across their entire economic life-cycle when accounting for both asset-related and non-asset-related risks. The avoided risk costs cover both types of risk cost (asset-related and non-asset-related) discussed above. THESL can use the comparison between different Costs of Ownership to show the benefits of replacing an obsolete asset configuration with a modern one. This comparison is provided for box construction, rear lot construction and feeder automation.

To assess the replacement of an obsolete configuration (e.g., rear lot construction) with a modern configuration (e.g., front lot underground service), THESL calculates the cost of ownership for each configuration and compares them. This is done using the formulas provided below:

- Cost of Ownership for Existing Assets (COO_E) = (NPV1 + NAR1)
- Cost of Ownership for New Assets (COO_N) = (NPV2 + NAR2)

Where:

- NPV1 represents cost of ownership of the assets in the existing configuration, which is being replaced, accounting for each asset type’s individual probability of failure multiplied by its individual impact of failure as previously defined.
- NAR1 represents the NPV calculation of non-asset risks associated with each asset type in the existing configuration, including animal-related, weather-related and human-

related impacts taking place over the life cycle of this infrastructure. Further explanation of the Non-Asset Risk calculation is provided below.

- NPV2 represents cost of ownership of the assets in the new configuration which is to be installed, accounting for each asset type's individual probability of failure multiplied by its individual impact of failure as previously defined
- NAR2 represents the NPV calculation of non-asset risks associated with the new configuration taking place over the life cycle of this infrastructure.

The overall project net present value is calculated as per the following formula shown below:

Project NPV = (COO_E – COO_N) – Project Cost

Thus, the Project NPV value, also called "Project Net Benefits," reflects the difference in the cost of ownership between the existing obsolete configuration and the proposed modern configuration, after the total cost of the project has been subtracted.

For the Job-Based Approach there are the additional cost consideration of **Sacrificed Risk** and the additional benefit of **Concurrent Intervention. Sacrificed Risk** is the cost of replacing assets before their optimal intervention time. In the job-based approach, all assets on a feeder are addressed in a single job, even though not every asset on the feeder has reached its optimal intervention time. This approach is used to obtain the benefits of **Concurrent Intervention**, which allow THESL to capture savings associated with addressing all assets in an area in a single job such as those associated with sending crews and equipment into an area only once rather them having them make multiple trips to address individual assets or asset classes on the same feeders.

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2010-0142

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Bulk metered residential buildings with up to six units also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	18.25	(per 30 days)
Smart Meter Funding Adder	$	0.68	(per 30 days)
Rate Rider for Contact Voltage – effective until April 30, 2012	$	0.16	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs – effective until April 30, 2013	$	0.24	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.01520	
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.00189)	
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.00043)	
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kWh	(0.00017)	
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012			
Applicable only for Non-RPP Customers	$/kWh	0.00055	
Retail Transmission Rate – Network Service Rate	$/kWh	0.00703	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00513	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	24.30	(per 30 days)
Smart Meter Funding Adder	$	0.68	(per 30 days)
Rate Rider for Contact Voltage – effective until April 30, 2012	$	0.16	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs – effective until April 30, 2013	$	0.69	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.02247	
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.00179)	
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.00044)	
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kWh	(0.00008)	
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.00055	
Retail Transmission Rate – Network Service Rate	$/kWh	0.00680	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00463	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited
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Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	35.56	(per 30 days)
Smart Meter Funding Adder	$	0.68	(per 30 days)
Rate Rider for Contact Voltage – effective until April 30, 2012	$	0.04	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs – effective until April 30, 2013	$	8.37	(per 30 days)
Rate Rider for Foregone Revenue (fixed) – effective until April 30, 2012	$	0.02	(per 30 days)
Distribution Volumetric Rate	$/kVA	5.5956	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kVA	(0.6119)	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kVA	(0.1807)	(per 30 days)
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kVA	0.0042	(per 30 days)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012			
Applicable only for Non-RPP Customers	$/kWh	0.00053	
Retail Transmission Rate – Network Service Rate	$/kW	2.4351	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7630	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2010-0142

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	686.46	(per 30 days)
Smart Meter Funding Adder	$	0.68	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs – effective until April 30, 2013	$	69.81	(per 30 days)
Rate Rider for Foregone Revenue (fixed) – effective until April 30, 2012	$	8.98	(per 30 days)
Distribution Volumetric Rate	$/kVA	4.4497	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kVA	(0.6922)	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kVA	(0.2133)	(per 30 days)
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kVA	0.1492	(per 30 days)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012			
Applicable only for Non-RPP Customers	$/kWh	0.00055	
Retail Transmission Rate – Network Service Rate	$/kW	2.3527	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7613	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2010-0142

LARGE USE SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	3,009.11	(per 30 days)
Smart Meter Funding Adder	$	0.68	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs – effective until April 30, 2013	$	304.62	(per 30 days)
Rate Rider for Foregone Revenue (fixed) – effective until April 30, 2012	$	45.52	(per 30 days)
Distribution Volumetric Rate	$/kVA	4.7406	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kVA	(0.7477)	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kVA	(0.2334)	(per 30 days)
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kVA	0.1609	(per 30 days)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.00053	
Retail Transmission Rate – Network Service Rate	$/kW	2.6820	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9567	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

STANDBY POWER SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component - APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility).

Service Charge	$	197.91	(per 30 days)
General Service 50 – 999 kW	$/kVA	5.5956	(per 30 days)
General Service 1,000 – 4,999 kW	$/kVA	4.4497	(per 30 days)
Large Use	$/kVA	4.7406	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	4.84	(per 30 days)
Connection Charge (per connection)	$	0.49	(per 30 days)
Rate Rider for Contact Voltage (per connection) – effective until April 30, 2012	$	1.51	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs – effective until April 30, 2013	$	0.09	(per 30 days)
Rate Rider for Foregone Revenue (fixed – per customer) – effective until April 30, 2012	$	(0.03)	(per 30 days)
Distribution Volumetric Rate	$/kWh	0.06070	
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kWh	(0.00197)	
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kWh	(0.00041)	
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kWh	(0.00007)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.00428	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00324	

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES – Delivery Component

Connection Charge (per connection)	$	1.30	(per 30 days)
Rate Rider for Contact Voltage (per connection) – effective until April 30, 2012	$	0.92	(per 30 days)
Rate Rider for Recovery of Late Payment Litigation Costs (per connection) – effective until April 30, 2013	$	0.04	(per 30 days)
Rate Rider for Foregone Revenue (fixed – per connection) – effective until April 30, 2012	$	(0.01)	(per 30 days)
Distribution Volumetric Rate	$/kVA	28.7248	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2012	$/kVA	(0.7499)	(per 30 days)
Rate Rider for Deferral/Variance Account Disposition (2011) – effective until April 30, 2012	$/kVA	(0.1868)	(per 30 days)
Rate Rider for Foregone Revenue (variable) – effective until April 30, 2012	$/kVA	(0.1658)	(per 30 days)
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2012 Applicable only for Non-RPP Customers	$/kWh	0.00054	
Retail Transmission Rate – Network Service Rate	$/kW	2.1658	(per 30 days)
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1022	(per 30 days)

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0013	
Standard Supply Service – Administration Charge (if applicable)	$	0.25	(per 30 days)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.18	(per 30 days)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
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EB-2010-0142

ALLOWANCES

Transformer Allowance for Ownership	$/kVA	(0.62)	(per 30 days)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration		
Duplicate Invoices for Previous Billing	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – No Disconnection	$	30.00
Disconnect/Reconnect Charges for non-payment of account		
- At Meter During Regular Hours	$	65.00
- At Meter After Hours	$	185.00
Install/Remove Load Control Device – During Regular hours	$	65.00
Install/Remove Load Control Device – After Regular hours	$	185.00
Disconnect/Reconnect at Pole – During Regular Hours	$	185.00
Disconnect/Reconnect at Pole – After Regular Hours	$	415.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Specific Charge for Access to the Power Poles – per pole/year (Third Party Attachments to Poles)	$	18.55
Specific Charge for Access to the Power Poles – per pole/year (Hydro Attachments on Third Party Poles)	$	(22.75)

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Retail Service Charges refer to services provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.

Establishing Service Agreements		
Standard charge (one-time charge), per agreement per retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$	0.50
Distributor-Consolidated Billing		
Standard billing charge, per month, per customer, per retailer	$	0.30
Retailer-Consolidated Billing		
Avoided cost credit, per month, per customer, per retailer	$	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, regardless of whether or not the STR can be processed	$	0.25
Processing fee, per request, applied to the requesting party if the request is processed	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2011
Implementation Date August 1, 2011

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EB-2010-0142

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Billing Determinant:

The billing determinant is the customer's metered energy consumption adjusted by the Total Loss Factor as approved by the Board and set out in this Schedule of Rates***.***

(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
(C) Customer less than 5,000 kW	1.0330
(D) Customer greater than 5,000 kW	1.0141

Total Loss Factors

Secondary Metered Customers	
(E) Customer less than 5,000 kW (B)*(C)	1.0376
(F) Customer greater than 5,000 kW (B)*(D)	1.0187
Primary metered customers	
(G) Customer less than 5,000 kW (A)*(E)	1.0272
(H) Customer greater than 5,000 kW (A)*(F)	1.0085

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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EB-2012-0064

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to accounts where electricity is used exclusively for residential purposes in separately metered living accommodations, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; separately metered dwellings within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	18.37
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	0.24
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2013	$	0.44
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.92
Distribution Volumetric Rate	$/kWh	0.01518
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kWh	0.00037
2012 ICM Rate Rider - Effective Until April 30 2015	$/kWh	0.00077
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	(0.00050)
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
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EB-2012-0064

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL

This classification is applicable to accounts where electricity is used exclusively for residential purposes in a multi-unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	17.12
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	0.24
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2013	$	0.17
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.34
Distribution Volumetric Rate	$/kWh	0.02582
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kWh	0.00063
Shared Tax Saving Rate Rider - Effective Until April 30 2013	$/kWh	(0.00010)
2012 ICM Rate Rider - Effective Until April 30 2015	$/kWh	0.00131
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	(0.00056)
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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EB-2012-0064

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	24.47
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	0.69
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2013	$	0.59
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.22
Distribution Volumetric Rate	$/kWh	0.02262
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kWh	0.00055
2012 ICM Rate Rider - Effective Until April 30 2015	$/kWh	0.00115
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	(0.00037)
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component		
Service Charge (Based on 30 day month)	$	35.80
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	8.37
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2013	$	0.86
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.79
Distribution Volumetric Rate	$/kVA	5.6337
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kVA	0.1357
Shared Tax Saving Rate Rider (per 30 days) - Effective Until April 30 2013	$/kVA	(0.0067)
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2813
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kVA	(0.0642)
Retail Transmission Rate – Network Service Rate	$/kW	2.6057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0648

MONTHLY RATES AND CHARGES – Regulatory Component		
Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	691.13
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	69.81
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2013	$	16.65
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	34.51
Distribution Volumetric Rate	$/kVA	4.4800
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kVA	0.1079
Shared Tax Saving Rate Rider (per 30 days) - Effective Until April 30 2013	$/kVA	(0.0056)
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2237
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kVA	(0.0508)
Retail Transmission Rate – Network Service Rate	$/kW	2.5175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0628

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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EB-2012-0064

LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	3029.57
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	304.62
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2013	$	72.98
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	151.26
Distribution Volumetric Rate	$/kVA	4.7728
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kVA	0.1150
Shared Tax Saving Rate Rider (per 30 days) - Effective Until April 30 2013	$/KVA	(0.0059)
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2383
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kVA	(0.0528)
Retail Transmission Rate – Network Service Rate	$/kW	2.8699
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.2917

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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EB-2012-0064

STANDBY - GENERAL SERVICE 50 - 1,000 KW SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	199.26
Distribution Volumetric Rate	$/kVA	5.6337

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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STANDBY - GENERAL SERVICE 1,000 - 5,000 KW SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	199.26
Distribution Volumetric Rate	$/kVA	4.4800

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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EB-2012-0064

STANDBY - LARGE USE SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	199.26
Distribution Volumetric Rate	$/kVA	4.7728

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
Implementation Date June 1, 2012

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	4.87
Service Charge (per connection)	$	0.49
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	0.09
Rate Rider for 2011 Unfunded Capex - (per customer 30 days) - Effective Until April 30 2013	$	0.01
Rate Rider for 2011 Unfunded Capex - (per connection 30 days) - Effective Until April 30 2013	$	0.12
2012 ICM Rate Rider (per customer/30 days) - Effective Until April 30 2015	$	0.02
2012 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.24
Distribution Volumetric Rate	$/kWh	0.06111
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kWh	0.00149
Shared Tax Saving Rate Rider - Effective Until April 30 2013	$/kWh	(0.00010)
2012 ICM Rate Rider - Effective Until April 30 2015	$/kWh	0.00309
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kWh	(0.00102)
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date June 1, 2012
Implementation Date June 1, 2012

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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	1.31
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per 30 days)	$	0.04
Rate Rider for 2011 Unfunded Capex - (per connection 30 days) - Effective Until April 30 2013	$	0.03
2012 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.07
Distribution Volumetric Rate	$/kVA	28.9201
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2013	$/kVA	0.6966
Shared Tax Saving Rate Rider (per 30 days) - Effective Until April 30 2013	$/kVA	(0.0425)
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	1.4439
Rate Rider for Deferral/Variance Account Disposition (2012)	$/kVA	(0.4529)
Retail Transmission Rate – Network Service Rate	$/kW	2.3175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.4621

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date June 1, 2012
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EB-2012-0064

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per 30 days)	$	5.18

Toronto Hydro-Electric System Limited
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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kVA	(0.62)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Customer Administration			
Duplicate invoices for previous billing	$	15.00	
Easement letter	$	15.00	
Income tax letter	$	15.00	
Request for other billing information	$	15.00	
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	
Returned cheque charge (plus bank charges)	$	15.00	
Special meter reads	$	30.00	
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	
Non-Payment of Account			
Late Payment - per month	%	1.50	
Late Payment - per annum	%	19.56	
Collection of account charge - no disconnection	$	30.00	
Disconnect/Reconnect at meter - during regular hours	$	65.00	
Disconnect/Reconnect at meter - after regular hours	$	185.00	
Disconnect/Reconnect at pole - during regular hours	$	185.00	
Disconnect/Reconnect at pole - after regular hours	$	415.00	/C
Install/Remove load control device - during regular hours	$	65.00	
Install/Remove load control device - after regular hours	$	185.00	
Specific Charge for Access to the Power Poles $/pole/year	$	22.35	
Specific Charge for Access to the Power Poles $/pole/year	$	18.55	
Specific Charge for Access to the Power Poles $/pole/year (Hydro Attachments on Third Party Poles)	$	(22.75)	

Toronto Hydro-Electric System Limited
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Effective Date June 1, 2012
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EB-2012-0064

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Billing Determinant:
The billing determinant is the customer's metered energy consumption adjusted by the Total Loss Factor as approved by the Board and set out in this Schedule of Rates.

(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
(C) Customer less than 5,000 kW	1.0330
(D) Customer greater than 5,000 kW	1.0141
Total Loss Factors	
Secondary Metered Customer	
(E) Customer less than 5,000 kW (B)*(C)	1.0376
(F) Customer greater than 5,000 kW (B)*(D)	1.1087
Primary metered customers	
(G) Primary Metered Customer less than 5,000 kW (A)*(E)	1.0272
(H) Primary Metered Customer greater than 5,000 kW (A)*(F)	1.0085

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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EB-2012-0064

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to accounts where electricity is used exclusively for residential purposes in separately metered living accommodations, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; separately metered dwellings within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	18.50
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$	0.43
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.92
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.23
Distribution Volumetric Rate	$/kWh	0.01528
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kWh	0.00036
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00077
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00103
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

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EB-2012-0064

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL

This classification is applicable to accounts where electricity is used exclusively for residential purposes in a multi-unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	17.23
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$	0.16
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.34
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.46
Distribution Volumetric Rate	$/kWh	0.02600
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kWh	0.00062
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00131
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00176
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	24.63
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$	0.58
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.22
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.64
Distribution Volumetric Rate	$/kWh	0.02278
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kWh	0.00054
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00115
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00154
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
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Implementation Date May 1, 2013

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EB-2012-0064

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	36.05
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$	0.84
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.79
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	2.40
Distribution Volumetric Rate	$/kVA	5.6720
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kVA	0.1324
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2813
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.3777
Retail Transmission Rate – Network Service Rate	$/kW	2.6057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0648

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
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EB-2012-0064

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION
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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	695.83
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$	16.25
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	34.51
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	46.34
Distribution Volumetric Rate	$/kVA	4.5104
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kVA	0.1053
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2237
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.3003
Retail Transmission Rate – Network Service Rate	$/kW	2.5175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0628

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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Implementation Date May 1, 2013

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LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	3050.17
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$	71.22
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	151.26
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	203.11
Distribution Volumetric Rate	$/kVA	4.8053
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kVA	0.1122
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2383
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.3200
Retail Transmission Rate – Network Service Rate	$/kW	2.8699
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.2917

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

Implementation Date May 1, 2013

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EB-2012-0064

STANDBY - GENERAL SERVICE 50 - 1,000 KW SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	200.61
Distribution Volumetric Rate	$/kVA	5.6720

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013

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STANDBY - GENERAL SERVICE 1,000 - 5,000 KW SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	200.61
Distribution Volumetric Rate	$/kVA	4.5104

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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STANDBY - LARGE USE SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	200.61
Distribution Volumetric Rate	$/kVA	4.8053

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2013
Implementation Date May 1, 2013

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	4.91
Service Charge (per connection/30 days)	$	0.50
Rate Rider for 2011 Unfunded Capex (per customer/30 days) - Effective Until April 30 2014	$	0.01
Rate Rider for 2011 Unfunded Capex (per connection/30 days) - Effective Until April 30 2014	$	0.11
2012 ICM Rate Rider (per customer/30 days) - Effective Until April 30 2015	$	0.02
2012 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.24
2013 ICM Rate Rider (per customer/30 days) - Effective Until April 30 2015	$	0.03
2013 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.33
Distribution Volumetric Rate	$/kWh	0.06153
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2014	$/kWh	0.00146
2012 ICM Rate Rider - Effective Until April 30, 2015	$/kWh	0.00309
2013 ICM Rate Rider - Effective Until April 30 2015	$/kWh	0.00415
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	\$/kWh	0.00520
Rural Rate Protection Charge	\$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Toronto Hydro-Electric System Limited
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STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	1.32
Rate Rider for 2011 Unfunded Capex (per connection/30 days) - Effective Until April 30 2014	$	0.03
2012 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.07
2013 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.09
Distribution Volumetric Rate	$/kVA	29.1168
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2014	$/kVA	0.6798
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	1.4439
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	1.9389
Retail Transmission Rate – Network Service Rate	$/kW	2.3175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.4621

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

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microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per 30 days)	$	5.18

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kVA	(0.62)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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Customer Administration

Duplicate invoices for previous billing	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Request for other billing information	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account			
Late Payment - per month	%	1.50	
Late Payment - per annum	%	19.56	
Collection of account charge - no disconnection	$	30.00	
Disconnect/Reconnect at meter - during regular hours	$	65.00	
Disconnect/Reconnect at meter - after regular hours	$	185.00	
Disconnect/Reconnect at pole - during regular hours	$	185.00	
Disconnect/Reconnect at pole - after regular hours	$	415.00	/C
Install/Remove load control device - during regular hours	$	65.00	
Install/Remove load control device - after regular hours	$	185.00	
Specific Charge for Access to the Power Poles $/pole/year	$	22.35	
Specific Charge for Access to the Power Poles $/pole/year	$	18.55	
Specific Charge for Access to the Power Poles $/pole/year (Hydro Attachments on Third Party Poles)	$	(22.75)	

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RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the r	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Billing Determinant:
The billing determinant is the customer's metered energy consumption adjusted by the Total Loss Factor as approved by the Board and set out in this Schedule of Rates.

(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
(C) Customer less than 5,000 kW	1.0330
(D) Customer greater than 5,000 kW	1.0141
Total Loss Factors	
Secondary Metered Customer	
(E) Customer less than 5,000 kW (B)*(C)	1.0376
(F) Customer greater than 5,000 kW (B)*(D)	1.1087
Primary metered customers	
(G) Primary Metered Customer less than 5,000 kW (A)*(E)	1.0272
(H) Primary Metered Customer greater than 5,000 kW (A)*(F)	1.0085

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

RESIDENTIAL SERVICE CLASSIFICATION

This classification is applicable to accounts where electricity is used exclusively for residential purposes in separately metered living accommodations, where the Competitive Sector Multi-Unit Residential classification is not applicable. Eligibility is restricted to dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex building, with a residential zoning; separately metered dwellings within a town house complex or apartment building; and bulk metered residential buildings with six or fewer units. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION
The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	18.62
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2015	$	0.42
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.92
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.23
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.46
Distribution Volumetric Rate	$/kWh	0.01538
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kWh	0.00035
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00077
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00103
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00039
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2014

Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

COMPETITIVE SECTOR MULTI-UNIT RESIDENTIAL

This classification is applicable to accounts where electricity is used exclusively for residential purposes in a multi-unit residential building, where unit metering is provided using technology that is substantially similar to that employed by competitive sector sub-metering providers. Use of electricity in non-residential units of multi-unit buildings does not qualify for this classification and will instead be subject to the applicable commercial classification. Further details concerning the terms of service are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	17.35
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2015	$	0.16
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.34
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.46
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.17
Distribution Volumetric Rate	$/kWh	0.02618
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kWh	0.0006
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00131
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00176
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00066
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2014

Implementation Date May 1, 2014

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EB-2012-0064

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	24.80
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2015	$	0.56
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.22
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.64
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.61
Distribution Volumetric Rate	$/kWh	0.02293
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kWh	0.00053
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00115
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00154
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00058
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2014

Implementation Date May 1, 2014

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EB-2012-0064

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 50 kW but less than 1,000 kW, or is forecast to be equal to or greater than 50 kW but less than 1,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	36.29
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2015	$	0.82
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	1.79
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	2.40
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	0.90
Distribution Volumetric Rate	$/kVA	5.7105
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kVA	0.1292
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2813
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.3777
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.1412
Retail Transmission Rate – Network Service Rate	$/kW	2.6057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0648

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

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EB-2012-0064

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than 1,000 kW but less than 5,000 kW, or is forecast to be equal to or greater than 1,000 kW but less than 5,000 kW. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	700.56
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2015	$	15.85
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	34.51
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	46.34
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	17.32
Distribution Volumetric Rate	$/kVA	4.5411
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kVA	0.1027
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2237
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.3003
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.1123
Retail Transmission Rate – Network Service Rate	$/kW	2.5175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0628

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2014
Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	3070.91
Smart Meter Funding Adder (per 30 days)	$	0.68
Rate Rider for 2011 Unfunded Capex (per 30 days) - Effective Until April 30 2015	$	69.46
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	151.26
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	203.11
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$	75.94
Distribution Volumetric Rate	$/kVA	4.8380
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kVA	0.1094
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.2383
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.3200
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.1196
Retail Transmission Rate – Network Service Rate	$/kW	2.8699
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.2917

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

STANDBY - GENERAL SERVICE 50 - 1,000 KW SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	201.97
Distribution Volumetric Rate	$/kVA	5.7105

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

STANDBY - GENERAL SERVICE 1,000 - 5,000 KW SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	201.97
Distribution Volumetric Rate	$/kVA	4.5411

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2014

Implementation Date May 1, 2014

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EB-2012-0064

STANDBY - LARGE USE SERVICE CLASSIFICATION

These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	201.97
Distribution Volumetric Rate	$/kVA	4.8380

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

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EB-2012-0064

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand at each location is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by THESL and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	4.94
Service Charge (per connection)	$	0.50
Rate Rider for 2011 Unfunded Capex (per customer/30 days) - Effective Until April 30 2015	$	0.01
Rate Rider for 2011 Unfunded Capex (per connection/30 days) - Effective Until April 30 2015	$	0.11
2012 ICM Rate Rider (per customer/30 days) - Effective Until April 30 2015	$	0.02
2012 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.24
2013 ICM Rate Rider (per customer/30 days) - Effective Until April 30 2015	$	0.03
2013 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.33
2014 ICM Rate Rider (per customer/30 days) - Effective Until April 30 2015	$	0.01
2014 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.12
Distribution Volumetric Rate	$/kWh	0.06195
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kWh	0.00142
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00309
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00415
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kWh	0.00155
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

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EB-2012-0064

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (Based on 30 day month)	$	1.33
Rate Rider for 2011 Unfunded Capex (per connection/30 days) - Effective Until April 30 2015	$	0.03
2012 ICM Rate Rider (per connection/30 days)	$	0.07
2013 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.09
2014 ICM Rate Rider (per connection/30 days) - Effective Until April 30 2015	$	0.03
Distribution Volumetric Rate	$/kVA	29.3148
Rate Rider for 2011 Unfunded Capex - Effective Until April 30 2015	$/kVA	0.663
2012 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	1.4439
2013 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	1.9389
2014 ICM Rate Rider (per 30 days) - Effective Until April 30 2015	$/kVA	0.7249
Retail Transmission Rate – Network Service Rate	$/kW	2.3175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.4621

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.00520
Rural Rate Protection Charge	$/kWh	0.00110
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

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EB-2012-0064

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per 30 days)	$	5.18

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

ALLOWANCES

Transformer Allowance for Ownership - per kVA of billing demand/30 days	$/kVA	(0.62)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Duplicate invoices for previous billing	$	15.00	
Easement letter	$	15.00	
Income tax letter	$	15.00	
Request for other billing information	$	15.00	
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	
Returned cheque charge (plus bank charges)	$	15.00	
Special meter reads	$	30.00	
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	

Non-Payment of Account

Late Payment - per month	%	1.50	
Late Payment - per annum	%	19.56	
Collection of account charge - no disconnection	$	30.00	
Disconnect/Reconnect at meter - during regular hours	$	65.00	
Disconnect/Reconnect at meter - after regular hours	$	185.00	
Disconnect/Reconnect at pole - during regular hours	$	185.00	
Disconnect/Reconnect at pole - after regular hours	$	415.00	/C

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Specific Charge for Access to the Power Poles $/pole/year	$	18.55
Specific Charge for Access to the Power Poles $/pole/year (Hydro Attachments on Third Party Poles)	$	(22.75)

Toronto Hydro-Electric System Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2014
Implementation Date May 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0064

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retaile	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Billing Determinant:
The billing determinant is the customer's metered energy consumption adjusted by the Total Loss Factor as approved by the Board and set out in this Schedule of Rates.

(A) Primary Metering Adjustment	0.9900
(B) Supply Facilities Loss Factor	1.0045
Distribution Loss Factors	
(C) Customer less than 5,000 kW	1.033
(D) Customer greater than 5,000 kW	1.0141
Total Loss Factors	
Secondary Metered Customer	
(E) Customer less than 5,000 kW (B)*(C)	1.0376
(F) Customer greater than 5,000 kW (B)*(D)	1.1087
Primary metered customers	
(G) Primary Metered Customer less than 5,000 kW (A)*(E)	1.0272
(H) Primary Metered Customer greater than 5,000 kW (A)*(F)	1.0085

V1.4

Ontario Energy Board

3RD Generation Incentive Regulation Model

Choose Your Utility:

Toronto Hydro-Electric System Limited
Wasaga Distribution Inc.

Application Type: IRM3
OEB Application #: EB-2011-0144
LDC Licence #: ED-2002-0497

Application Contact Information

Name:	Anthony Lam
Title:	Economist
Phone Number:	416 542 2876
Email Address:	alam@torontohydro.com
We are applying for rates effective:	June 1, 2012
Please indicate the version of Microsoft Excel that you are currently using:	Excel 2007

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

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Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges.
Note: The microFIT class does not exist in the drop-down menu below as it will automatically be inserted into your proposed Tariff Schedule.

Rate Class

Residential
Residential Urban
General Service Less Than 50 kW
General Service 50 to 999 kW
General Service 1,000 to 4,999 kW
Large Use > 5000 kW
Standby - General Service 50 - 1,000 kW
Standby - General Service 1,000 - 5,000 kW
Standby - Large Use
Unmetered Scattered Load
Street Lighting
Sentinel Lighting
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please note that unlike the Distribution Volumetric Rates, which will be entered in the following two tabs, all current Monthly Fixed Charges, including the base charges, must be entered on this tab. Please enter the descriptions of the current Monthly Fix Charges exactly as they appear on your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct class exactly as it appears on the tariff. Once a description is selected or entered into the green cells, the input cells for the "Unit", "Amount", and "Effective Date" will appear. Please note that the base Monthly Fixed Charge is identified in the drop-down list as a "Service Charge" to coincide with the description on the tariff. Please do not enter more than one "Service Charge" for each class for which a base monthly fixed charge applies. **Note: Do not enter Standard Supply Service Rate. The rate will appear automatically on the final Tariff of Rates and Charges.

Rate Description	Unit	Amount	Effective Until Date
Residential			
Service Charge (Based on 30 day month)	$	18.25	April 30, 2013
Smart Meter Funding Adder	$	0.68	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.24	April 30, 2013
Rate Rider for Contact Voltage (per 30 days)	$	0.16	April 30, 2012
Residential Urban			
Service Charge (Based on 30 day month)	$	17.00	April 30, 2013
Smart Meter Funding Adder	$	0.68	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.24	April 30, 2013
Rate Rider for Contact Voltage (per 30 days)	$	0.16	April 30, 2012
General Service Less Than 50 kW			
Service Charge (Based on 30 day month)	$	24.30	April 30, 2013
Smart Meter Funding Adder	$	0.68	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	0.69	April 30, 2013
Rate Rider for Contact Voltage (per 30 days)	$	0.16	April 30, 2012
General Service 50 to 999 kW			
Service Charge (Based on 30 day month)	$	35.56	April 30, 2013
Smart Meter Funding Adder	$	0.68	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	8.37	April 30, 2013
Rate Rider for Foregone Revenue Recovery	$	0.02	April 30, 2012
Rate Rider for Contact Voltage (per 30 days)	$	0.04	April 30, 2012
General Service 1,000 to 4,999 kW			
Service Charge (Based on 30 day month)	$	686.46	April 30, 2013
Smart Meter Funding Adder	$	0.68	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	69.81	April 30, 2013
Rate Rider for Foregone Revenue Recovery	$	8.98	April 30, 2012

Large Use > 5000 kW

Service Charge (Based on 30 day month)	$	3009.11	April 30, 2013
Smart Meter Funding Adder	$	0.68	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	304.62	April 30, 2013
Rate Rider for Foregone Revenue Recovery	$	45.52	April 30, 2012

Unmetered Scattered Load

Service Charge (Based on 30 day month)	$	4.84	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.09	April 30, 2013
Rate Rider for Foregone Revenue Recovery	$	(0.03)	April 30, 2012
Rate Rider for Contact Voltage (per 30 days)	$	1.51	April 30, 2012

Sentinel Lighting

Service Charge (per connection)	$	0.49	April 30, 2013

Street Lighting

Service Charge (Based on 30 day month)	$	1.30	April 30, 2013
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	0.04	April 30, 2013
Rate Rider for Foregone Revenue Recovery	$	(0.01)	April 30, 2012
Rate Rider for Contact Voltage (per 30 days)	$	0.92	April 30, 2012

Standby - General Service 50 - 1,000 kW

Service Charge (Based on 30 day month)	$	197.91	April 30, 2013

Standby - General Service 1,000 - 5,000 kW

Service Charge (Based on 30 day month)	$	197.91	April 30, 2013

Standby - Large Use

Service Charge (Based on 30 day month)	$	197.91	April 30, 2013

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

For each class, please enter the base Distribution Volumetric Rates ("DVR") from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus and input cells in columns labeled "Unit" and "Amount".

Rate Description	Unit	Amount
Residential	$/kWh	0.01507
Residential Urban	$/kWh	0.02565
General Service Less Than 50 kW	$/kWh	0.02247
General Service 50 to 999 kW	$/kVA	5.59560
General Service 1,000 to 4,999 kW	$/kVA	4.44970
Large Use > 5000 kW	$/kVA	4.74060
Unmetered Scattered Load	$/kWh	0.06070
Sentinel Lighting		
Street Lighting	$/kVA	28.72480
Standby - General Service 50 - 1,000 kW	$/kVA	5.59560
Standby - General Service 1,000 - 5,000 kW	$/kVA	4.44970
Standby - Large Use	$/kVA	4.74060

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please enter the descriptions of all other current Variable Rates, including any applicable low voltage charges, rate riders, rate adders, etc. from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus located under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description of the associated rate in the green cells exactly as it appears on the tariff. Once a description is selected or entered into the green cells, the input cells for the "Unit", "Amount", and "Effective Date" will appear. **Note: Do not enter the WMSR or RRRP Rate below. These rates will appear automatically on the final Tariff of Rates and Charges.

Rate Description	Unit	Amount	Effective Until Date
Residential			
Rate Rider for Deferral/Variance Account Disposition (2010)	$/kWh	(0.00189)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kWh	(0.00043)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00055	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kWh	(0.00017)	April 30, 2012
Residential Urban			
Rate Rider for Deferral/Variance Account Disposition (2010)	$/kWh	(0.00189)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kWh	(0.00043)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00055	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kWh	(0.00017)	April 30, 2012
General Service Less Than 50 kW			
Rate Rider for Deferral/Variance Account Disposition (2010)	$/kWh	(0.00179)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kWh	(0.00044)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00055	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kWh	0.00008	April 30, 2012

General Service 50 to 999 kW

Rate Rider for Deferral/Variance Account Disposition (2010)	$/kVA	(0.61190)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kVA	(0.18070)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00053	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kVA	0.00420	April 30, 2012

General Service 1,000 to 4,999 kW

Rate Rider for Deferral/Variance Account Disposition (2010)	$/kVA	(0.69220)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kVA	(0.21330)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00055	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kVA	0.14920	April 30, 2012

Large Use > 5000 kW

Rate Rider for Deferral/Variance Account Disposition (2010)	$/kVA	(0.74770)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kVA	(0.23340)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00053	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kVA	0.16090	April 30, 2012

Unmetered Scattered Load

Rate Rider for Deferral/Variance Account Disposition (2010)	$/kWh	(0.00197)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kWh	(0.00041)	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kWh	(0.00007)	April 30, 2012

Sentinel Lighting

Street Lighting

Rate Rider for Deferral/Variance Account Disposition (2010)	$/kVA	(0.74990)	April 30, 2012
Rate Rider for Deferral/Variance Account Disposition (2011)	$/kVA	(0.18680)	April 30, 2012
Rate Rider for Global Adjustment Sub-Account Disposition – Applicable only for Non-RPP Customers	$/kWh	0.00054	April 30, 2012
Rate Rider for Recovery of Foregone Revenue	$/kVA	(0.16580)	April 30, 2012

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please enter your RTS-Network Rates from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct classes exactly as it appears on the tariff.

Rate Description	Unit	Amount
Residential		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00703
Residential Urban		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00703
General Service Less Than 50 kW		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00680
General Service 50 to 999 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.43510
General Service 1,000 to 4,999 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.35270
Large Use > 5000 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.68200
Unmetered Scattered Load		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00428
Sentinel Lighting		
Street Lighting		
Retail Transmission Rate – Network Service Rate	$/kW	2.16580

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

Ontario Energy Board

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Please enter your RTS-Connection Rates from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus und the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells und the correct classes exactly as it appears on the tariff.

Rate Description	Unit	Amount
Residential		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00513
Residential Urban		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00513
General Service Less Than 50 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00463
General Service 50 to 999 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.76300
General Service 1,000 to 4,999 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.76130
Large Use > 5000 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.95670
Unmetered Scattered Load		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00324
Sentinel Lighting		

Street Lighting		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.10220

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 and Account 1562. Enter information into green cells only. Lines 51-61 contain footnotes and further instructions.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December 31, 2009 balances, the starting point for your entries below should be the adjustment column AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

		2005									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [5]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-Account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**										
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

2A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

3 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

4 Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 and 29.

5 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

6 If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31, 2011 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from January 1, 2011 to April 30, 11 on the December 31, 2010 balance. The projected interested is recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision.

7 Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has been completed, and the audited financial statements support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 49).

Toronto Hydro-Electric System Limited - EB-2011-0144

lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 152
ootnotes and further instructions.

you have received approval to dispose of balances from prior years, the starting point for entries in the 2012
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the Decemb
djustment column AV for principal and column BA for interest. This will allow for the correct starting point fo
equiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

2006

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [5]	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**					-$ 6,824,131	$ 1,356,940	-$ 296,612			$ 1,060,328
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	-$ 6,824,131	$ 1,356,940	-$ 296,612	$ -	$ -	$ 1,060,328
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs v

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Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved di

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support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, incl

Toronto Hydro-Electric System Limited - EB-2011-0144

lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 152
ootnotes and further instructions.

you have received approval to dispose of balances from prior years, the starting point for entries in the 2012
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djustment column AV for principal and column BA for interest. This will allow for the correct starting point fo
equiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

		2007									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [5]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	-$ 6,824,131				-$ 6,824,131	$ 1,060,328	-$ 322,611			$ 737,717
Group 1 Total + 1521 + 1562		-$ 6,824,131	$ -	$ -	$ -	-$ 6,824,131	$ 1,060,328	-$ 322,611	$ -	$ -	$ 737,717
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

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Toronto Hydro-Electric System Limited - EB-2011-0144

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you have received approval to dispose of balances from prior years, the starting point for entries in the 2012
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the Decemb
djustment column AV for principal and column BA for interest. This will allow for the correct starting point fo
equiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Account Descriptions	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [5]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	-$ 6,824,131				-$ 6,824,131	$ 737,717	-$ 271,600			$ 466,117
Group 1 Total + 1521 + 1562		-$ 6,824,131	$ -	$ -	$ -	-$ 6,824,131	$ 737,717	-$ 271,600	$ -	$ -	$ 466,117
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

**For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.**

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

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Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from Janu
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Toronto Hydro-Electric System Limited - EB-2011-0144

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you have received approval to dispose of balances from prior years, the starting point for entries in the 2012
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djustment column AV for principal and column BA for interest. This will allow for the correct starting point fo
equiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

		2009									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [5]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ -			$ 910,834	$ 910,834	$ -			$ 43,562	$ 43,562
RSVA - Wholesale Market Service Charge	1580	$ -			-$ 54,927,284	-$ 54,927,284	$ -			-$ 2,852,619	-$ 2,852,619
RSVA - Retail Transmission Network Charge	1584	$ -			-$ 15,203,484	-$ 15,203,484	$ -			-$ 738,236	-$ 738,236
RSVA - Retail Transmission Connection Charge	1586	$ -			-$ 10,736,969	-$ 10,736,969	$ -			-$ 1,364,052	-$ 1,364,052
RSVA - Power (excluding Global Adjustment)	1588	$ -			-$ 259,129	-$ 259,129	$ -			$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -			$ 44,599,726	$ 44,599,726	$ -			-$ 15,819	-$ 15,819
Recovery of Regulatory Asset Balances	1590	$ -			$ 2	$ 2	$ -			$ -	$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -			-$ 491,772	-$ 491,772	$ -			-$ 276,556	-$ 276,556
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -			-$ 2,787,938	-$ 2,787,938	$ -			-$ 42,064	-$ 42,064
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	-$ 38,896,013	-$ 38,896,013	$ -	$ -	$ -	-$ 5,245,783	-$ 5,245,783
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	-$ 83,495,739	-$ 83,495,739	$ -	$ -	$ -	-$ 5,229,964	-$ 5,229,964
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ 44,599,726	$ 44,599,726	$ -	$ -	$ -	-$ 15,819	-$ 15,819
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	-$ 6,824,131				-$ 6,824,131	$ 466,117	-$ 77,624			$ 388,493
Group 1 Total + 1521 + 1562		-$ 6,824,131	$ -	$ -	-$ 38,896,013	-$ 45,720,144	$ 466,117	-$ 77,624	$ -	-$ 5,245,783	-$ 4,857,290
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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have a negative figure) as per the related Board decision.**

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs

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eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the Decemb
djustment column AV for principal and column BA for interest. This will allow for the correct starting point fo
equiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [5]	Board-Approved Disposition during 2010	Other [3] Adjustments during Q1 2010	Other [3] Adjustments during Q2 2010	Other [3] Adjustments during Q3 2010	Other [3] Adjustments during Q4 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [3]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts														
LV Variance Account	1550	$ 910,834	$ 186,439	$ 713,449					$ 383,824	$ 43,562	$ 3,654	$ 44,084		$ 3,133
RSVA - Wholesale Market Service Charge	1580	-$ 54,927,284	-$ 26,238,240	-$ 47,563,346					-$ 33,602,178	-$ 2,852,619	-$ 249,451	-$ 2,924,115		-$ 177,956
RSVA - Retail Transmission Network Charge	1584	-$ 15,203,484	$ 7,764,568	-$ 18,324,237					$ 10,885,321	-$ 738,236	$ 38,920	-$ 792,643		$ 93,327
RSVA - Retail Transmission Connection Charge	1586	-$ 10,736,969	$ 3,097,923	-$ 7,432,471					-$ 206,576	-$ 1,364,052	-$ 17,950	-$ 1,383,545		$ 1,543
RSVA - Power (excluding Global Adjustment)	1588	-$ 259,129	$ -	-$ 264,726					$ 5,597	$ -	$ -	$ -		$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 44,599,726	-$ 8,632,018	$ 15,859,509					$ 20,108,199	-$ 15,819	$ 152,866	-$ 91,679		$ 228,725
Recovery of Regulatory Asset Balances	1590	$ 2	$ -	$ -					$ 2	$ -	$ -	$ -		$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	-$ 491,772	$ -	$ -					-$ 491,772	-$ 276,556	-$ 9,743	$ -		-$ 286,299
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	-$ 2,787,938	$ 2,424,338	$ -					-$ 363,600	-$ 42,064	-$ 35,321	$ -		-$ 77,385
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 38,896,013	-$ 21,396,991	-$ 57,011,821	$ -	$ -	$ -	$ -	-$ 3,281,183	-$ 5,245,783	-$ 117,027	-$ 5,147,897	$ -	-$ 214,913
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 83,495,739	-$ 12,764,973	-$ 72,871,331	$ -	$ -	$ -	$ -	-$ 23,389,381	-$ 5,229,964	-$ 269,892	-$ 5,056,218	$ -	-$ 443,638
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ 44,599,726	-$ 8,632,018	$ 15,859,509	$ -	$ -	$ -	$ -	$ 20,108,199	-$ 15,819	$ 152,866	-$ 91,679	$ -	$ 228,725
Special Purpose Charge Assessment Variance Account	**1521**		-$ 6,123,220	-$ 9,697,579				-$ 3,050,473	$ 523,886		-$ 19,401			-$ 19,401
Deferred Payments in Lieu of Taxes	**1562**	-$ 6,824,131							-$ 6,824,131	$ 388,493	-$ 54,422			$ 334,071
Group 1 Total + 1521 + 1562		-$ 45,720,144	-$ 27,520,211	-$ 66,709,400	$ -	$ -	$ -	-$ 3,050,473	-$ 9,581,428	-$ 4,857,290	-$ 190,849	-$ 5,147,897	$ -	$ 99,758
The following is not included in the total claim but are included on a memo basis:														
Board-Approved CDM Variance Account	1567								$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 14,427,499	-$ 2,314,616	-$ 11,109,564					-$ 5,632,551	$ -	-$ 62,633			-$ 62,633
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592		$ 733,340					$ 366,600	$ 1,099,940	$ -	$ 2,932			$ 2,932
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -	-$ 733,340	$ -				-$ 366,600	-$ 1,099,940	$ -	-$ 2,932			-$ 2,932
Disposition and Recovery of Regulatory Balances[7]	1595	$ -	-$ 33,680,187						-$ 33,680,187	$ -	-$ 5,375,322			-$ 5,375,322

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djustment column AV for principal and column BA for interest. This will allow for the correct starting point fo
quiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

		2011				Projected Interest on Dec-31-10 Balances			2.1.7 RRR	
Account Descriptions	**Account Number**	**Principal Disposition during 2011 - instructed by Board**	**Interest Disposition during 2011 - instructed by Board**	**Closing Principal Balances as of Dec 31-10 Adjusted for Dispositions during 2011**	**Closing Interest Balances as of Dec 31-10 Adjusted during 2011 Disposition**	**Projected Interest from Jan 1, 2011 to December 31, 2011 on Dec 31 -10 balance adjusted for disposition during 2011 [5]**	**Projected Interest from January 1, 2012 to April 30, 2012 on Dec 31 -10 balance adjusted for disposition during 2011 [6, 7]**	**Total Claim**	**As of Dec 31-10 [4]**	**Variance RRR vs. 2010 Balance *(Principal + Interest)***
Group 1 Accounts										
LV Variance Account	1550	$ 197,386	$ 4,053	$ 186,438	-$ 920	$ 2,754	$ 914	$ 189,185	$ 386,957	$ 0
RSVA - Wholesale Market Service Charge	1580	-$ 7,363,938	-$ 137,577	-$ 26,238,240	-$ 40,378	-$ 367,991	-$ 128,567	-$ 26,775,177	-$ 33,780,134	$ 0
RSVA - Retail Transmission Network Charge	1584	$ 3,120,753	$ 72,499	$ 7,764,568	$ 20,828	$ 114,139	$ 38,046	$ 7,937,581	$ 10,978,648	$ 0
RSVA - Retail Transmission Connection Charge	1586	-$ 3,304,499	-$ 48,830	$ 3,097,923	$ 50,373	$ 45,532	$ 15,180	$ 3,209,008	-$ 205,033	-$ 0
RSVA - Power (excluding Global Adjustment)	1588	$ -	$ -	$ 5,597	$ -	$ -	$ -	$ 5,597	$ 5,597	$ 0
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -	-$ 228,725	$ 20,108,199	$ 457,450	$ 66,966	$ 98,558	$ 20,731,172	$ 20,336,924	-$ 0
Recovery of Regulatory Asset Balances	1590	$ -	$ -	$ 2	$ -	$ -	$ -	$ 2	$ 2	$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	-$ 491,772	-$ 296,776	$ -	$ 10,477	-$ 10,477	$ -	$ 0	-$ 778,072	$ 0
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -	$ -	-$ 363,600	-$ 77,385	-$ 80,251	$ -	-$ 521,235	-$ 440,985	-$ 0
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		-$ 7,842,070	-$ 635,356	$ 4,560,887	$ 420,443	-$ 229,327	$ 24,130	$ 4,776,133	-$ 3,496,096	$ 0
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		-$ 7,842,070	-$ 406,631	-$ 15,547,312	-$ 37,007	-$ 296,293	-$ 74,428	-$ 15,955,039	-$ 23,833,019	$ 0
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	-$ 228,725	$ 20,108,199	$ 457,450	$ 66,966	$ 98,558	$ 20,731,172	$ 20,336,924	-$ 0
Special Purpose Charge Assessment Variance Account	**1521**					$ 67,502	$ 2,590	$ 574,577	$ 3,554,958	$ 3,050,473
Deferred Payments in Lieu of Taxes	**1562**			-$ 6,824,131	$ 334,071	-$ 100,315	-$ 33,438	-$ 6,623,813	$ 1,103,311	$ 7,593,371
Group 1 Total + 1521 + 1562		-$ 7,842,070	-$ 635,356	-$ 2,263,244	$ 754,514	-$ 262,140	-$ 6,718	-$ 1,273,103	$ 1,162,173	$ 10,643,844
The following is not included in the total claim but are included on a memo basis:										
Board-Approved CDM Variance Account	1567							$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$ 3,317,935	-$ 55,042	-$ 2,314,616	$ 12,643	-$ 34,025	-$ 10,665	-$ 2,366,898	-$ 5,674,950	$ 20,234
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592					-$ 15,046	$ 5,390	$ 1,093,216	$ 736,332	-$ 366,540
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ 15,046	-$ 5,390	-$ 1,093,216	-$ 736,332	$ 366,540
Disposition and Recovery of Regulatory Balances[7]	1595			-$ 33,680,187	-$ 5,375,322			-$ 39,055,509	-$ 39,055,509	$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sig
have a negative figure) as per the related Board decision.

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of t

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved di

Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the trans
If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31,
Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from Janu
recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances app

Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period h
support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, incl

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3RD Generation Incentive Regulation Model

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In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]
Residential	$/kWh	4,886,977,489		559,659,628	-	204,720,003			18%
Residential Urban	$/kWh	99,791,184		11,421,625	-	4,600,284			2%
General Service Less Than 50 kW	$/kWh	2,139,318,076		437,628,634	-	67,255,470			10%
General Service 50 to 999 kW	$/kVA	10,116,374,153	26,935,191	6,900,756,638	-	156,294,314			37%
General Service 1,000 to 4,999 kW	$/kVA	4,626,928,262	10,587,119	4,177,096,302	-	51,343,590			19%
Large Use > 5000 kW	$/kVA	2,376,778,323	4,993,733	2,272,251,249	-	25,370,430			12%
Unmetered Scattered Load	$/kWh	56,231,585			-	4,681,925			0%
Sentinel Lighting					-				
Street Lighting	$/kVA	110,165,016	322,023	110,128,567	-	11,789,364			0%
Standby - General Service 50 - 1,000 kW					-				
Standby - General Service 1,000 - 5,000 kW					-				
Standby - Large Use					-				
Total		24,412,564,088	42,838,067	14,468,942,643	-	526,055,380	0%	0%	100%

Total Claim (including Accounts 1521 and 1562)	-$	1,273,103
Total Claim for Threshold Test (All Group 1 Accounts)	$	4,776,133
Threshold Test [3] (Total Claim per kWh)		0.00020

Claim does not meet the threshold test. If data has been entered on Sheet 9 for Accounts 1521 and 1562, the model will only dispose of Accounts 1521 and 1562.

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balance.

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[3] The Threshold Test does not include the amount in 1521 nor 1562.

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Deferral / Variance Account Work Form

Toronto Hydro-Electric System Limited - EB-2011-0144

No input required. This worksheet allocates the deferral/variance account balances (Group 1, 1521, 1588 GA and 1562) to the appropriate classes.

Allocation of Group 1 Accounts (Excluding Account 1588 - Global Adjustment)

Rate Class	Units	Billed kWh	% kWh	1550	1580	1584	1586	1588*	1590	1595 (2008)	1595 (2009)	1521	Total
Residential	$/kWh	4,886,977,489	20.02%	0	0	0	0	0	0	0	0	115,021	115,021
Residential Urban	$/kWh	99,791,184	0.41%	0	0	0	0	0	0	0	0	2,349	2,349
General Service Less Than 50 kW	$/kWh	2,139,318,076	8.76%	0	0	0	0	0	0	0	0	50,351	50,351
General Service 50 to 999 kW	$/kVA	10,116,374,153	41.44%	0	0	0	0	0	0	0	0	238,100	238,100
General Service 1,000 to 4,999 kW	$/kVA	4,626,928,262	18.95%	0	0	0	0	0	0	0	0	108,900	108,900
Large Use > 5000 kW	$/kVA	2,376,778,323	9.74%	0	0	0	0	0	0	0	0	55,940	55,940
Unmetered Scattered Load	$/kWh	56,231,585	0.23%	0	0	0	0	0	0	0	0	1,323	1,323
Sentinel Lighting	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Street Lighting	$/kVA	110,165,016	0.45%	0	0	0	0	0	0	0	0	2,593	2,593
Standby - General Service 50 - 1,000 kW	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - General Service 1,000 - 5,000 kW	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - Large Use	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Total		24,412,564,088	100.00%	189,185	(26,775,177)	7,937,581	3,209,008	5,597	2	0	(521,235)	574,577	574,577

** RSVA - Power (Excluding Global Adjustment)*

1588 RSVA - Power (Global Adjustment Sub-Account)

Rate Class	non-RPP kWh	% kWh	1588
Residential	559,659,628	3.87%	-
Residential Urban	11,421,625	0.08%	-
General Service Less Than 50 kW	437,628,634	3.02%	-
General Service 50 to 999 kW	6,900,756,638	47.69%	-
General Service 1,000 to 4,999 kW	4,177,096,302	28.87%	-
Large Use > 5000 kW	2,272,251,249	15.70%	-
Unmetered Scattered Load	-	0.00%	-
Sentinel Lighting	-	0.00%	-
Street Lighting	110,128,567	0.76%	-
Standby - General Service 50 - 1,000 kW	-	0.00%	-
Standby - General Service 1,000 - 5,000 kW	-	0.00%	-
Standby - Large Use	-	0.00%	-
Total	14,468,942,643	100.00%	20,731,172

Allocation of Account 1562

	% of Distribution Revenue		Allocation of Balance in Account 1562
Residential	38.9%	-	2,577,727
Residential Urban	0.9%	-	57,924
General Service Less Than 50 kW	12.8%	-	846,846
General Service 50 to 999 kW	29.7%	-	1,967,976
General Service 1,000 to 4,999 kW	9.8%	-	646,492
Large Use > 5000 kW	4.8%	-	319,451
Unmetered Scattered Load	0.9%	-	58,952
Sentinel Lighting	0.0%		-
Street Lighting	2.2%	-	148,445
Standby - General Service 50 - 1,000 kW	0.0%		-
Standby - General Service 1,000 - 5,000 kW	0.0%		-
Standby - Large Use	0.0%		-
Total	100.0%	-	6,623,813

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Deferral / Variance Account Work Form

Toronto Hydro-Electric System Limited - EB-2011-0144

No input required. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and associated rate riders for the global adjustment sub-account.

Please indicate the Rate Rider Recovery Period (in years): 1

Rate Class	Unit	Billed kWh	Billed kW	Accounts Allocated by kWh/kW (RPP) or Distribution Revenue	Deferral/Variance Account Rate Rider		Account 1588 Global Adjustment	Billed kWh or Estimated kW for Non-RPP	Global Adjustment Rate Rider
Residential	$/kWh	4,886,977,489	-	-$ 2,462,706	($0.00050)	$/kWh	$ -	559,659,628	$0.00000
Residential Urban	$/kWh	99,791,184	-	-$ 55,576	($0.00056)	$/kWh	$ -	11,421,625	$0.00000
General Service Less Than 50 kW	$/kWh	2,139,318,076	-	-$ 796,494	($0.00037)	$/kWh	$ -	437,628,634	$0.00000
General Service 50 to 999 kW	$/kVA	10,116,374,153	26,935,191	-$ 1,729,876	($0.06422)	$/kVA	$ -	-	$0.00000
General Service 1,000 to 4,999 kW	$/kVA	4,626,928,262	10,587,119	-$ 537,592	($0.05078)	$/kVA	$ -	-	$0.00000
Large Use > 5000 kW	$/kVA	2,376,778,323	4,993,733	-$ 263,511	($0.05277)	$/kVA	$ -	-	$0.00000
Unmetered Scattered Load	$/kWh	56,231,585	-	-$ 57,629	($0.00102)	$/kWh	$ -	-	$0.00000
Sentinel Lighting	-	-	-	$ -	$0.00000		$ -	-	$0.00000
Street Lighting	$/kVA	110,165,016	322,023	-$ 145,853	($0.45293)	$/kVA	$ -	-	$0.00000
Standby - General Service 50 - 1,000 kW	-	-	-	$ -	$0.00000		$ -	-	$0.00000
Standby - General Service 1,000 - 5,000 kW	-	-	-	$ -	$0.00000		$ -	-	$0.00000
Standby - Large Use	-	-	-	$ -	$0.00000		$ -	-	$0.00000
Total		24,412,564,088	42,838,067	-$ 6,049,236			$ -		

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Below is a listing of the current Monthly Fixed Charges. All rates with expired effective dates have been removed. In columns "B", "K", and "M" (green cells), please enter all additional Monthly Fixed Charges you are proposing (eg: Smart Meter Funding Adder, etc). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable).

Rate Description	Unit	Amount	Effective Until Date	Proposed Amount	Effective Until Date
Residential					
Service Charge (Based on 30 day month)	$	18.25	April 30, 2013		
Smart Meter Funding Adder	$	0.68	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.24	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.44	April 30 2013
2012 ICM Rate Rider (per customer/30 days)	$			0.92	April 30 2015
	$				
Residential Urban					
Service Charge (Based on 30 day month)	$	17.00	April 30, 2013		
Smart Meter Funding Adder	$	0.68	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.24	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.17	April 30 2013
2012 ICM Rate Rider (per customer/30 days)	$			0.34	April 30 2015
	$				
General Service Less Than 50 kW					
Service Charge (Based on 30 day month)	$	24.30	April 30, 2013		
Smart Meter Funding Adder	$	0.68	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	0.69	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.59	April 30 2013
2012 ICM Rate Rider (per customer/30 days)	$			1.22	April 30 2015
	$				
General Service 50 to 999 kW					
Service Charge (Based on 30 day month)	$	35.56	April 30, 2013		
Smart Meter Funding Adder	$	0.68	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	8.37	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$			0.86	April 30 2013
2012 ICM Rate Rider (per 30 days)	$			1.79	April 30 2015
	$				
General Service 1,000 to 4,999 kW					
Service Charge (Based on 30 day month)	$	686.46	April 30, 2013		
Smart Meter Funding Adder	$	0.68	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	69.81	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$			16.65	April 30 2013
2012 ICM Rate Rider (per 30 days)	$			34.51	April 30 2015
	$				
Large Use > 5000 kW					
Service Charge (Based on 30 day month)	$	3009.11	April 30, 2013		
Smart Meter Funding Adder	$	0.68	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	304.62	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$			72.98	April 30 2013
2012 ICM Rate Rider (per 30 days)	$			151.26	April 30 2015
	$				
Unmetered Scattered Load					
Service Charge (Based on 30 day month)	$	4.84	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.09	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$			0.01	April 30 2013
2012 ICM Rate Rider (per 30 days)	$			0.02	April 30 2015
	$				
Sentinel Lighting					
Service Charge (per connection)	$	0.49	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$			0.12	April 30 2013
2012 ICM Rate Rider (per 30 days)	$			0.24	April 30 2015
	$				
Street Lighting					
Service Charge (Based on 30 day month)	$	1.30	April 30, 2013		
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	0.04	April 30, 2013		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$			0.03	April 30 2013
2012 ICM Rate Rider (per 30 days)	$			0.07	April 30 2015
	$				
Standby - General Service 50 - 1,000 kW					
Service Charge (Based on 30 day month)	$	197.91	April 30, 2013		
	$				
	$				
	$				
Standby - General Service 1,000 - 5,000 kW					
Service Charge (Based on 30 day month)	$	197.91	April 30, 2013		
	$				
	$				
	$				
Standby - Large Use					
Service Charge (Based on 30 day month)	$	197.91	April 30, 2013		
	$				
	$				
	$				

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Below is a listing of the current Distribution Volumetric Rates other than the base rates. All rates with expired effective dates have been removed.
In columns "B", "K", and "M" (green cells), please enter all additional volumetric rates you are proposing (eg: LRAM/SSM, Tax Adjustments, etc.).
Please ensure that the word "Rider" or "Adder" is included in the description (as applicable).

Rate Description	Unit	Amount	Effective Until Date	Proposed Amount	Effective Until Date
Residential					
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00037	April 30 2013
2012 ICM Rate Rider	$/kWh			0.00077	April 30 2015
Residential Urban					
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00063	April 30 2013
Shared Tax Saving Rate Rider	$/kWh			(0.00010)	April 30 2013
2012 ICM Rate Rider	$/kWh			0.00131	April 30 2015
General Service Less Than 50 kW					
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00055	April 30 2013
2012 ICM Rate Rider	$/kWh			0.00115	April 30 2015
General Service 50 to 999 kW					
Rate Rider for 2011 Unfunded Capex	$/kVA			0.13570	April 30 2013
Shared Tax Saving Rate Rider (per 30 days)	$/kVA			(0.00670)	April 30 2013
2012 ICM Rate Rider (per 30 days)	$/kVA			0.28130	April 30 2015
General Service 1,000 to 4,999 kW					
Rate Rider for 2011 Unfunded Capex	$/kVA			0.10790	April 30 2013
Shared Tax Saving Rate Rider (per 30 days)	$/kVA			(0.00560)	April 30 2013
2012 ICM Rate Rider (per 30 days)	$/kVA			0.22370	April 30 2015
Large Use > 5000 kW					
Rate Rider for 2011 Unfunded Capex	$/kVA			0.11500	April 30 2013
Shared Tax Saving Rate Rider (per 30 days)	$/kVA			(0.00590)	April 30 2013
2012 ICM Rate Rider (per 30 days)	$/kVA			0.23830	April 30 2015
Unmetered Scattered Load					
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00149	April 30 2013
Shared Tax Saving Rate Rider	$/kWh			(0.00010)	April 30 2013
2012 ICM Rate Rider	$/kWh			0.00309	April 30 2015

Sentinel Lighting			
Street Lighting			
Rate Rider for 2011 Unfunded Capex	$/kVA	0.69660	April 30 2013
Shared Tax Saving Rate Rider (per 30 days)	$/kVA	(0.04250)	April 30 2013
2012 ICM Rate Rider (per 30 days)	$/kVA	1.44390	April 30 2015
Standby - General Service 50 - 1,000 kW			
Standby - General Service 1,000 - 5,000 kW			
Standby - Large Use			

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Current RTSR-Network Rates are listed below. In column "K", please enter your proposed RTSR-Network Rates as per Sheet 13 of the Board's RTSR Workform.

Rate Description	Unit	Current Amount	% Adjustment	Proposed Amount
Residential				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00703	7.004%	0.00752
Residential Urban				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00703	7.004%	0.00752
General Service Less Than 50 kW				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00680	7.004%	0.00728
General Service 50 to 999 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.43510	7.004%	2.60566
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.35270	7.004%	2.51749
Large Use > 5000 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.68200	7.004%	2.86985
Unmetered Scattered Load				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00428	7.004%	0.00458
Sentinel Lighting				
Street Lighting				
Retail Transmission Rate – Network Service Rate	$/kW	2.16580	7.004%	2.31750
Standby - General Service 50 - 1,000 kW				
Standby - General Service 1,000 - 5,000 kW				
Standby - Large Use				

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Current RTSR-Connection Rates are listed below. In column "K", please enter your proposed RTSR-Connection Rates as per Sheet 13 of the Board's RTSR Workform.

Rate Description	Unit	Current Amount	% Adjustment	Proposed Amount
Residential				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00513	17.120%	0.00601
Residential Urban				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00513	17.120%	0.00601
General Service Less Than 50 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00463	17.120%	0.00542
General Service 50 to 999 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.76300	17.120%	2.06482
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.76130	17.120%	2.06283
Large Use > 5000 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.95670	17.120%	2.29168
Unmetered Scattered Load				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00324	17.120%	0.00379
Sentinel Lighting				
Street Lighting				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.10220	17.120%	2.46209
Standby - General Service 50 - 1,000 kW				
Standby - General Service 1,000 - 5,000 kW				
Standby - Large Use				

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If applicable, please enter any adjustments related to the revenue to cost ratio model into columns H and K.
The Price Escalator has been set at the 2011 values and will be updated by Board staff. The Stretch Factor Value will also be updated by Board staff.

Price Escalator 2.00% **Productivity Factor** 0.72% **Price Cap Index** 0.68%

Choose Stretch Factor Group III **Associated Stretch Factor Value** 0.6%

Rate Description	Unit	Current MFC	MFC Adjustment from R/C Model	Current Volumetric Charge	Unit	DVR Adjustment from R/C Model	Price Cap Index	Proposed MFC	Proposed Volumetric Charge
Residential	$	18.25		0.01507	$/kWh		0.680%	18.37	0.01518
Residential Urban	$	17.00		0.02565	$/kWh		0.680%	17.12	0.02582
General Service Less Than 50 kW	$	24.30		0.02247	$/kWh		0.680%	24.47	0.02262
General Service 50 to 999 kW	$	35.56		5.59560	$/kVA		0.680%	35.80	5.63365
General Service 1,000 to 4,999 kW	$	686.46		4.44970	$/kVA		0.680%	691.13	4.47996
Large Use > 5000 kW	$	3,009.11		4.74060	$/kVA		0.680%	3,029.57	4.77284
Unmetered Scattered Load	$	4.84		0.06070	$/kWh		0.680%	4.87	0.06111
Sentinel Lighting	$	0.49					0.680%	0.49	
Street Lighting	$	1.30		28.72480	$/kVA		0.680%	1.31	28.92013
Standby - General Service 50 - 1,000 kW	$	197.91		5.59560	$/kVA		0.680%	199.26	5.63365
Standby - General Service 1,000 - 5,000 kW	$	197.91		4.44970	$/kVA		0.680%	199.26	4.47996
Standby - Large Use	$	197.91		4.74060	$/kVA		0.680%	199.26	4.77284

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Please enter the descriptions of the current Loss Factors from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menu in the column labeled "Loss Factors". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct classes.

Loss Factors	Current
Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0376
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.1087
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0272
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0085

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The standard Allowance rates have been included as default entries. If you have different rates, please make the appropriate corrections in the below. As well, please enter the current Specific Service Charges below. The standard Retail Service Charges have been entered below. If you rates, please make the appropriate corrections in columns B, D or E as applicable (cells are unlocked).

ALLOWANCES

	UNIT	CURRENT
Transformer Allowance for Ownership - per kVA of billing demand/30 days	$/kVA	(0.62)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Duplicate invoices for previous billing	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Request for other billing information	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month		%	1.50
Late Payment - per annum		%	19.56
Collection of account charge - no disconnection		$	30.00
Disconnect/Reconnect at meter - during regular hours		$	65.00
Disconnect/Reconnect at meter - after regular hours		$	185.00
Disconnect/Reconnect at pole - during regular hours		$	185.00
Disconnect/Reconnect at pole - after regular hours	**/C**	$	415.00

Other

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Specific Charge for Access to the Power Poles $/pole/year	$	18.55
Specific Charge for Access to the Power Poles $/pole/year	$	-22.75

Residential	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	18.25	18.25	1	18.37	18.37	0.12	0.7%
Distribution	800	0.01520	12.16	800	0.01518	12.14	(0.02)	-0.1%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	800	(0.00189)	(1.51)	-	-	-	1.51	-100.0%
Regulatory Assets - 2011 Rate Rider	800	(0.00043)	(0.34)	-	-	-	0.34	-100.0%
Contact Voltage	1	0.16	0.16	-	-	-	(0.16)	-100.0%
Late Payment Penalty	1	0.24	0.24	1	0.24	0.24	-	0.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	800	(0.00017)	(0.14)	-	-	-	0.14	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	0.44	0.44	0.44	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	800	0.00037	0.30	0.30	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
ICM Rate Rider - MFC	-	-	-	1	0.92	0.92	0.92	n/a
ICM Rate Rider - DVR	-	-	-	800	0.00077	0.62	0.62	n/a
Deferral/Variance Account Rate Rider	-	-	-	800	(0.00050)	(0.40)	(0.40)	n/a
Sub Total A - Distribution			29.50			33.31	3.81	12.9%
RTST - Network	830	0.00703	5.84	830.08	0.00752	6.24	0.41	7.0%
RTSR - Connection	830	0.00513	4.26	830.08	0.00601	4.99	0.73	17.2%
Sub Total B (including Sub-Total A) - Distribution			39.59			44.54	4.95	12.5%
Wholesale Market Rate	830	0.00520	4.32	830	0.00520	4.32	-	0.0%
RRRP	830	0.00130	1.08	830	0.00110	0.91	(0.17)	-15.4%
DRC	800	0.00700	5.60	800	0.00700	5.60	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	830	-	-	830	-	-	-	n/a
Cost of Power Commodity - 1st Tier	600	0.071	42.60	600	0.075	45.00	2.40	5.6%
Cost of Power Commodity - 2nd Tier	230	0.083	19.10	230	0.088	20.25	1.15	6.0%
Total Bill (including Sub-Total B)			112.53			120.86	8.33	7.4%

	kWh
Consumption Details	**800**
Total Loss Factor	1.0376

Competitive Sector Multi-Unit Residential	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	18.25	18.25	1	17.12	17.12	(1.13)	-6.2%
Distribution	334	0.01520	5.08	334	0.02582	8.62	3.55	69.9%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	334	(0.00189)	(0.63)	-	-	-	0.63	-100.0%
Regulatory Assets - 2011 Rate Rider	334	(0.00043)	(0.14)	-	-	-	0.14	-100.0%
Contact Voltage	1	0.16	0.16	-	-	-	(0.16)	-100.0%
Late Payment Penalty	1	0.24	0.24	1	0.24	0.24	-	0.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	334	(0.00017)	(0.06)	-	-	-	0.06	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	0.17	0.17	0.17	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	334	0.00063	0.21	0.21	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	334	(0.00010)	(0.03)	(0.03)	n/a
ICM Rate Rider - MFC	-	-	-	1	0.34	0.34	0.34	n/a
ICM Rate Rider - DVR	-	-	-	334	0.00131	0.44	0.44	n/a
Deferral/Variance Account Rate Rider	-	-	-	334	(0.00056)	(0.19)	(0.19)	n/a
Sub Total A - Distribution			23.58			27.60	4.03	17.1%
RTST - Network	347	0.00703	2.44	346.56	0.00752	2.61	0.17	7.0%
RTSR - Connection	347	0.00513	1.78	346.56	0.00601	2.08	0.30	17.2%
Sub Total B (including Sub-Total A) - Distribution			27.79			32.29	4.50	16.2%
Wholesale Market Rate	347	0.00520	1.80	347	0.00520	1.80	-	0.0%
RRRP	347	0.00130	0.45	347	0.00110	0.38	(0.07)	-15.4%
DRC	334	0.00700	2.34	334	0.00700	2.34	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	347	-	-	347	-	-	-	n/a
Cost of Power Commodity - 1st Tier	347	0.071	24.61	347	0.075	25.99	1.39	5.6%
Cost of Power Commodity - 2nd Tier	-	0.083	-	-	0.088	-	-	n/a
Total Bill (including Sub-Total B)			57.24			63.05	5.82	10.2%

	kWh
Consumption Details	**334**
Total Loss Factor	1.0376

GS < 50 kW	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	24.30	24.30	1	24.47	24.47	0.17	0.7%
Distribution	2,000	0.02247	44.94	2,000	0.02262	45.24	0.30	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	2,000	(0.00179)	(3.58)	-	-	-	3.58	-100.0%
Regulatory Assets - 2011 Rate Rider	2,000	(0.00044)	(0.88)	-	-	-	0.88	-100.0%
Contact Voltage	1	0.16	0.16	-	-	-	(0.16)	-100.0%
Late Payment Penalty	1	0.69	0.69	1	0.69	0.69	-	0.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	2,000	(0.00008)	(0.16)	-	-	-	0.16	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	0.59	0.59	0.59	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	2,000	0.00055	1.10	1.10	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
ICM Rate Rider - MFC	-	-	-	1	1.22	1.22	1.22	n/a
ICM Rate Rider - DVR	-	-	-	2,000	0.00115	2.30	2.30	n/a
Deferral/Variance Account Rate Rider	-	-	-	2,000	(0.00037)	(0.74)	(0.74)	n/a
Sub Total A - Distribution			66.15			75.55	9.40	14.2%
RTST - Network	2,075	0.00680	14.11	2,075	0.00728	15.11	1.00	7.1%
RTSR - Connection	2,075	0.00463	9.61	2,075	0.00542	11.25	1.64	17.1%
Sub Total B (including Sub-Total A) - Distribution			89.87			101.91	12.04	13.4%
Wholesale Market Rate	2,075	0.0052	10.79	2,075	0.0052	10.79	-	0.0%
RRRP	2,075	0.0013	2.70	2,075	0.0011	2.28	(0.42)	-15.4%
DRC	2,000	0.0070	14.00	2,000	0.0070	14.00	-	0.0%
Standard Supply Service Charge	1.00	0.25	0.25	1.00	0.25	0.25	-	0.0%
Special Purpose Charge	2,075	-	-	2,075	-	-	-	n/a
Cost of Power Commodity - 1st Tier	750	0.071	53.25	750	0.075	56.25	3.00	5.6%
Cost of Power Commodity - 2nd Tier	1,325	0.083	109.99	1,325	0.088	116.62	6.63	6.0%
Total Bill (including Sub-Total B)			280.85			302.10	21.25	7.6%

	kWh
Consumption Details	**2,000.00**
Total Loss Factor	1.0376

GS > 50 < 1000	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	35.56	35.56	1	35.80	35.80	0.24	0.7%
Distribution	388	5.5956	2,171.09	388	5.6337	2,185.88	14.78	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	388	(0.6119)	(237.42)	-	-	-	237.42	-100.0%
Regulatory Assets - Global Adjustment - Non RPP	150,000	0.00053	79.50	-	-	-	(79.50)	-100.0%
Regulatory Assets - 2011 Rate Rider	388	(0.18070)	(70.11)	-	-	-	70.11	-100.0%
Contact Voltage	1	0.04	0.04	-	-	-	(0.04)	-100.0%
Late Payment Penalty	1	8.37	8.37	1	8.37	8.37	-	0.0%
Foregone Revenue Rate Rider - fixed rate	1	0.02	0.02	-	-	-	(0.02)	-100.0%
Foregone Revenue Rate Rider - variable rate	388	0.00420	1.63	-	-	-	(1.63)	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	0.86	0.86	0.86	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	388	0.1357	52.65	52.65	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	388	(0.0067)	(2.60)	(2.60)	n/a
ICM Rate Rider - MFC	-	-	-	1	1.79	1.79	1.79	n/a
ICM Rate Rider - DVR	-	-	-	388	0.2813	109.14	109.14	n/a
Deferral/Variance Account Rate Rider	-	-	-	388	(0.06420)	(24.91)	(24.91)	n/a
Sub Total A - Distribution			1,989.36			2,367.66	378.30	19.0%
RTST - Network	349	2.4351	849.85	349	2.6057	909.39	59.54	7.0%
RTSR - Connection	349	1.7630	615.29	349	2.0648	720.62	105.33	17.1%
Sub Total B (including Sub-Total A) - Distribution			3,454.50			3,997.67	543.17	15.7%
Wholesale Market Rate	155,640	0.0052	809.33	155,640	0.0052	809.33	-	0.0%
RRRP	155,640	0.0013	202.33	155,640	0.0011	171.20	(31.13)	-15.4%
DRC	150,000	0.0070	1,050.00	150,000	0.0070	1,050.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	155,640	-	-	155,640	-	-	-	n/a
Cost of Power Commodity - 1st Tier	750	0.071	53.25	750	0.075	56.25	3.00	5.6%
Cost of Power Commodity - 2nd Tier	154,890	0.083	12,855.87	154,890	0.088	13,630.32	774.45	6.0%
Total Bill (including Sub-Total B)			18,425.53			19,715.02	1,289.49	7.0%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	150,000	349	388	430	90%	100%
Total Loss Factor	1.0376					

GS > 1000 < 5000	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	686.46	686.46	1	691.13	691.13	4.67	0.7%
Distribution	1,778	4.4497	7,911.57	1,778	4.4800	7,965.44	53.87	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	1,778	(0.6922)	(1,230.73)	-	-	-	1,230.73	-100.0%
Regulatory Assets - Global Adjustment - Non RPP	800,000	0.00055	440.00	-	-	-	(440.00)	-100.0%
Regulatory Assets - 2011 Rate Rider	1,778	(0.2133)	(379.25)	-	-	-	379.25	-100.0%
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1.00	69.81	69.81	1.00	69.81	69.81	-	0.0%
Foregone Revenue Rate Rider - fixed rate	1.00	8.98	8.98	-	-	-	(8.98)	-100.0%
Foregone Revenue Rate Rider - variable rate	1,778	0.1492	265.28	-	-	-	(265.28)	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	16.65	16.65	16.65	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	1,778	0.10790	191.85	191.85	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	1,778	(0.00560)	(9.96)	(9.96)	n/a
ICM Rate Rider - MFC	-	-	-	1	34.51	34.51	34.51	n/a
ICM Rate Rider - DVR	-	-	-	1,778	0.22370	397.74	397.74	n/a
Deferral/Variance Account Rate Rider	-	-	-	1,778	(0.05080)	(90.32)	(90.32)	n/a
Sub Total A - Distribution			7,772.80			9,267.53	1,494.73	19.2%
RTST - Network	1,600	2.3527	3,764.32	1,600	2.5175	4,028.00	263.68	7.0%
RTSR - Connection	1,600	1.7613	2,818.08	1,600	2.0628	3,300.48	482.40	17.1%
Sub Total B (including Sub-Total A) - Distribution			14,355.20			16,596.01	2,240.81	15.6%
Wholesale Market Rate	830,080	0.0052	4,316.42	830,080	0.0052	4,316.42	-	0.0%
RRRP	830,080	0.0013	1,079.10	830,080	0.0011	913.09	(166.02)	-15.4%
DRC	800,000	0.0070	5,600.00	800,000	0.0070	5,600.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	830,080	-	-	830,080	-	-	-	n/a
Cost of Power Commodity - 1st Tier	750	0.071	53.25	750	0.075	56.25	3.00	5.6%
Cost of Power Commodity - 2nd Tier	829,330	0.083	68,834.39	829,330	0.088	72,981.04	4,146.65	6.0%
Total Bill (including Sub-Total B)			94,238.61			100,463.05	6,224.44	6.6%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	800,000	1,600	1,778	500	90%	100%
Total Loss Factor	1.0376					

LU	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	3,009.11	3,009.11	1	3,029.57	3,029.57	20.46	0.7%
Distribution	9,434	4.7406	44,722.82	9,434	4.7728	45,026.60	303.77	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	9,434	(0.7477)	(7,053.80)	-	-	-	7,053.80	-100.0%
Regulatory Assets - Global Adjustment - Non RPP	4,500,000	0.00053	2,385.00	-	-	-	(2,385.00)	-100.0%
Regulatory Assets - 2011 Rate Rider	9,434	(0.23340)	(2,201.90)	-	-	-	2,201.90	-100.0%
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	304.62	304.62	1	304.62	304.62	-	0.0%
Foregone Revenue Rate Rider - fixed rate	1	45.52	45.52	-	-	-	(45.52)	-100.0%
Foregone Revenue Rate Rider - variable rate	9,434	0.16090	1,517.93	-	-	-	(1,517.93)	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	72.98	72.98	72.98	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	9,434	0.1150	1,084.91	1,084.91	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	9,434	(0.0059)	(55.66)	(55.66)	n/a
ICM Rate Rider - MFC	-	-	-	1	151.26	151.26	151.26	n/a
ICM Rate Rider - DVR	-	-	-	9,434	0.2383	2,248.12	2,248.12	n/a
Deferral/Variance Account Rate Rider	-	-	-	9,434	(0.05280)	(498.12)	(498.12)	n/a
Sub Total A - Distribution			42,729.98			51,364.96	8,634.98	20.2%
RTST - Network	8,491	2.6820	22,772.86	8,491	2.8699	24,368.32	1,595.46	7.0%
RTSR - Connection	8,491	1.9567	16,614.34	8,491	2.2917	19,458.82	2,844.49	17.1%
Sub Total B (including Sub-Total A) - Distribution			82,117.19			95,192.11	13,074.92	15.9%
Wholesale Market Rate	4,584,150	0.0052	23,837.58	4,584,150	0.0052	23,837.58	-	0.0%
RRRP	4,584,150	0.0013	5,959.40	4,584,150	0.00110	5,042.57	(916.83)	-15.4%
DRC	4,500,000	0.0070	31,500.00	4,500,000	0.0070	31,500.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	4,584,150	-	-	4,584,150	-	-	-	n/a
Cost of Power Commodity - 1st Tier	750	0.071	53.25	750	0.075	56.25	3.00	5.6%
Cost of Power Commodity - 2nd Tier	4,583,400	0.083	380,422.20	4,583,400	0.088	403,339.20	22,917.00	6.0%
Total Bill (including Sub-Total B)			523,889.86			558,967.95	35,078.09	6.7%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	4,500,000	8,491	9,434	530	90%	100%
Total Loss Factor	1.0187					

Street Lights	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Connection Charge	162,353	1.30	211,059.44	162,353	1.31	212,682.97	1,623.53	0.8%
Distribution	25,755	28.7248	739,807.22	25,755	28.9201	744,837.18	5,029.95	0.7%
Regulatory Assets - 2011/12 Rate Rider	25,755	(0.7499)	(19,313.67)	-	-	-	19,313.67	-100.0%
Regulatory Assets - 2011 Rate Rider	25,755	(0.18680)	(4,811.03)	-	-	-	4,811.03	-100.0%
Contact Voltage	162,353	0.92	149,365.14	-	-	-	(149,365.14)	-100.0%
Late Payment Penalty	162,353	0.04	6,494.14	162,353	0.04	6,494.14	-	0.0%
Foregone Revenue Rate Rider - fixed rate	162,353	(0.01000)	(1,623.53)	-	-	-	1,623.53	-100.0%
Foregone Revenue Rate Rider - variable rate	25,755	(0.16580)	(4,270.18)	-	-	-	4,270.18	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	162,353.42	0.03	4,870.60	4,870.60	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	25,755.00	0.6966	17,940.93	17,940.93	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	25,755.00	(0.0425)	(1,094.59)	(1,094.59)	n/a
ICM Rate Rider - MFC	-	-	-	162,353.42	0.07	11,364.74	11,364.74	n/a
ICM Rate Rider - DVR	-	-	-	25,755.00	1.4439	37,187.64	37,187.64	n/a
Deferral/Variance Account Rate Rider	-	-	-	25,755.00	(0.45290)	(11,664.44)	(11,664.44)	n/a
Sub Total A - Distribution			1,076,707.52			1,022,619.18	(54,088.34)	-5.0%
RTST - Network	25,755	2.1658	55,780.18	25,755	2.3175	59,687.21	3,907.03	7.0%
RTSR - Connection	25,755	2.1022	54,142.16	25,755	2.4621	63,411.39	9,269.22	17.1%
Sub Total B (including Sub-Total A) - Distribution		-	1,186,629.86		-	1,145,717.78	(40,912.09)	-3.4%
Wholesale Market Rate	9,620,365	0.0052	50,025.90	9,620,365	0.0052	50,025.90	-	0.0%
RRRP	9,620,365	0.0013	12,506.47	9,620,365	0.00110	10,582.40	(1,924.07)	-15.4%
DRC	9,271,748	0.0070	64,902.23	9,271,748	0.0070	64,902.23	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	9,620,365	-	-	9,620,365	-	-	-	n/a
Cost of Power Commodity - 1st Tier	750	0.071	53.25	750	0.075	56.25	3.00	5.6%
Cost of Power Commodity - 2nd Tier	9,619,615	0.083	798,428.06	9,619,615	0.088	846,526.14	48,098.08	6.0%
Total Bill (including Sub-Total B)			2,112,546.03			2,117,810.95	5,264.92	0.2%

	kWh	Connections	kW	KVA	**Hours Use**	**PF**	**Net/Conn**
Consumption Details	9,271,747.50	162,353	25,755	25,755.00	360	100%	100%
Total Loss Factor	1.0376						

USL	Current			2012			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	4.84	4.84	1	4.87	4.87	0.03	0.6%
Connection Charge	1	0.49	0.49	1	0.49	0.49	-	0.0%
Distribution	365	0.06070	22.16	365	0.06111	22.31	0.15	0.7%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	365	(0.00197)	(0.72)	-	-	-	0.72	-100.0%
Regulatory Assets - 2011 Rate Rider	365	(0.00041)	(0.15)	-	-	-	0.15	-100.0%
Contact Voltage	1	1.51	1.51	-	-	-	(1.51)	-100.0%
Late Payment Penalty	1	0.09	0.09	1	0.09	0.09	-	0.0%
Foregone Revenue Rate Rider - fixed rate - customer	1	(0.03)	(0.03)	-	-	-	0.03	-100.0%
Foregone Revenue Rate Rider - variable rate - connection	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	365	(0.00007)	(0.03)	-	-	-	0.03	-100.0%
2011 Unfunded Capex Rate Rider - MFC	-	-	-	1	0.01	0.01	0.01	n/a
2011 Unfunded Capex Rate Rider - MFC (Connection)	-	-	-	1	0.12	0.12	0.12	n/a
2011 Unfunded Capex Rate Rider - DVR	-	-	-	365	0.00149	0.54	0.54	n/a
Shared Tax Savings Rate Rider - DVR	-	-	-	365	(0.00010)	(0.04)	(0.04)	n/a
ICM Rate Rider - MFC	-	-	-	1	0.02	0.02	0.02	n/a
ICM Rate Rider - MFC (Connection)	-	-	-	1	0.24	0.24	0.24	n/a
ICM Rate Rider - DVR	-	-	-	365	0.00309	1.13	1.13	n/a
Deferral/Variance Account Rate Rider	-	-	-	365	(0.00102)	(0.37)	(0.37)	n/a
Sub Total A - Distribution			28.16			29.41	1.25	4.4%
RTST - Network	379	0.00428	1.62	379	0.00458	1.73	0.11	7.0%
RTSR - Connection	379	0.00324	1.23	379	0.00379	1.44	0.21	17.0%
Sub Total B (including Sub-Total A) - Distribution			31.01			32.58	1.57	5.1%
Wholesale Market Rate	379	0.0052	1.97	379	0.00520	1.97	-	0.0%
RRRP	379	0.0013	0.49	379	0.00110	0.42	(0.08)	-15.4%
DRC	365	0.0070	2.56	365	0.00700	2.56	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25000	0.25	-	0.0%
Special Purpose Charge	-	-	-	-	-	-	-	n/a
Cost of Power Commodity - 1st Tier	379	0.071	26.89	379	0.075	28.40	1.51	5.6%
Cost of Power Commodity - 2nd Tier	-	0.083	-	-	0.088	-	-	n/a
Total Bill (including Sub-Total B)			63.17			66.17	3.01	4.8%

	Kwh	Customer	Connection
Consumption Details	365	1	1
Total Loss Factor	1.0376		

V1.4

Ontario Energy Board

3RD Generation Incentive Regulation Model

Choose Your Utility:

Toronto Hydro-Electric System Limited
Wasaga Distribution Inc.

Application Type: IRM3
OEB Application #: EB-2011-0144
LDC Licence #: ED-2002-0497

Application Contact Information

Name:	Anthony Lam
Title:	Economist
Phone Number:	416 542 2876
Email Address:	alam@torontohydro.com
We are applying for rates effective:	May 1, 2013
Please indicate the version of Microsoft Excel that you are currently using:	Excel 2007

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

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3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges.
Note: The microFIT class does not exist in the drop-down menu below as it will automatically be inserted into your proposed Tariff Schedule.

Rate Class

Residential
Residential Urban
General Service Less Than 50 kW
General Service 50 to 999 kW
General Service 1,000 to 4,999 kW
Large Use > 5000 kW
Standby - General Service 50 - 1,000 kW
Standby - General Service 1,000 - 5,000 kW
Standby - Large Use
Unmetered Scattered Load
Street Lighting
Sentinel Lighting
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class

Toronto Hydro-Electric System Limited - EB-2011-0144

Please note that unlike the Distribution Volumetric Rates, which will be entered in the following two tabs, all current Monthly Fixed Charges, including the base charges, must be entered on this tab. Please enter the descriptions of the current Monthly Fix Charges exactly as they appear on your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct class exactly as it appears on the tariff. Once a description is selected or entered into the green cells, the input cells for the "Unit", "Amount", and "Effective Date" will appear. Please note that the base Monthly Fixed Charge is identified in the drop-down list as a "Service Charge" to coincide with the description on the tariff. Please do not enter more than one "Service Charge" for each class for which a base monthly fixed charge applies. **Note: Do not enter Standard Supply Service Rate. The rate will appear automatically on the final Tariff of Rates and Charges.

Rate Description	Unit	Amount	Effective Until Date
Residential			
Service Charge (Based on 30 day month)	$	18.37	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2014
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.24	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	0.92	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.44	April 30, 2013
Residential Urban			
Service Charge (Based on 30 day month)	$	17.12	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2014
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.24	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	0.34	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.17	April 30, 2013
General Service Less Than 50 kW			
Service Charge (Based on 30 day month)	$	24.47	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2014
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	0.69	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	1.22	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.59	April 30, 2013
General Service 50 to 999 kW			
Service Charge (Based on 30 day month)	$	35.80	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2014
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	8.37	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	1.79	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.86	April 30, 2013
General Service 1,000 to 4,999 kW			
Service Charge (Based on 30 day month)	$	691.13	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2014
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	69.81	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	34.51	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	16.65	April 30, 2013

Large Use > 5000 kW			
Service Charge (Based on 30 day month)	$	3029.57	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2014
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	304.62	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	151.26	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	72.98	April 30, 2013
Unmetered Scattered Load			
Service Charge (Based on 30 day month)	$	4.87	April 30, 2015
Rate Rider for Recovery of Late Payment Penalty Litigation Costs (per customer)	$	0.09	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$	0.02	April 30, 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.01	April 30, 2013
Sentinel Lighting			
Service Charge (per connection)	$	0.49	April 30, 2015
2012 ICM Rate Rider (per connection/30 days)	$	0.24	April 30, 2015
2011 Unfunded Capex Rate Rider (per connection/30 days)	$	0.12	April 30, 2013
Street Lighting			
Service Charge (Based on 30 day month)	$	1.31	April 30, 2015
Rate Rider for Recovery of Late Payment Penalty Litigation Costs	$	0.04	April 30, 2013
2012 ICM Rate Rider (per connection/30 days)	$	0.07	April 30, 2015
2011 Unfunded Capex Rate Rider (per connection/30 days)	$	0.03	April 30, 2013
Standby - General Service 50 - 1,000 kW			
Service Charge (Based on 30 day month)	$	199.26	April 30, 2015
Standby - General Service 1,000 - 5,000 kW			
Service Charge (Based on 30 day month)	$	199.26	April 30, 2015
Standby - Large Use			
Service Charge (Based on 30 day month)	$	199.26	April 30, 2015

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

For each class, please enter the base Distribution Volumetric Rates ("DVR") from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus and input cells in columns labeled "Unit" and "Amount".

Rate Description	Unit	Amount
Residential	$/kWh	0.01518
Residential Urban	$/kWh	0.02582
General Service Less Than 50 kW	$/kWh	0.02262
General Service 50 to 999 kW	$/kVA	5.63365
General Service 1,000 to 4,999 kW	$/kVA	4.47996
Large Use > 5000 kW	$/kVA	4.77284
Unmetered Scattered Load	$/kWh	0.06111
Sentinel Lighting		
Street Lighting	$/kVA	28.92013
Standby - General Service 50 - 1,000 kW	$/kVA	5.63365
Standby - General Service 1,000 - 5,000 kW	$/kVA	4.47996
Standby - Large Use	$/kVA	4.77284

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Toronto Hydro-Electric System Limited - EB-2011-0144

Please enter the descriptions of all other current Variable Rates, <u>including</u> any applicable low voltage charges, rate riders, rate adders, etc. from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus located under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description of the associated rate in the green cells <u>exactly</u> as it appears on the tariff. Once a description is selected or entered into the green cells, the input cells for the "Unit", "Amount", and "Effective Date" will appear. **Note: Do not enter the WMSR or RRRP Rate below. These rates will appear automatically on the final Tariff of Rates and Charges.

Rate Description	Unit	Amount	Effective Until Date
Residential			
2011 Unfunded Capex Rate Rider (per 30 days)	$/kWh	0.00037	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00077	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per 30 days)	$/kWh	(0.00050)	April 30, 2013
Residential Urban			
2011 Unfunded Capex Rate Rider (per 30 days)	$/kWh	0.00063	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00131	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per 30 days)	$/kWh	(0.00056)	April 30, 2013
General Service Less Than 50 kW			
2011 Unfunded Capex Rate Rider (per 30 days)	$/kWh	0.00055	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00115	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per 30 days)	$/kWh	(0.00037)	April 30, 2013
General Service 50 to 999 kW			

2011 Unfunded Capex Rate Rider (per 30 days)	$/kVA	0.13570	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$/kVA	0.28130	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per 30 days)	$/kVA	(0.06420)	April 30, 2013

General Service 1,000 to 4,999 kW

2011 Unfunded Capex Rate Rider (per 30 days)	$/kVA	0.10790	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$/kVA	0.22370	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per 30 days)	$/kVA	(0.05080)	April 30, 2013

Large Use > 5000 kW

2011 Unfunded Capex Rate Rider (per 30 days)	$/kVA	0.11500	April 30, 2013
2012 ICM Rate Rider (per 30 days)	$/kVA	0.23830	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per 30 days)	$/kVA	(0.05280)	April 30, 2013

Unmetered Scattered Load

2011 Unfunded Capex Rate Rider (per customer/30 days)	$/kWh	0.00149	April 30, 2013
2012 ICM Rate Rider (per customer/30 days)	$/kWh	0.00309	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per customer/30 days)	$/kWh	(0.00102)	April 30, 2013

Sentinel Lighting

Street Lighting

2011 Unfunded Capex Rate Rider (per connection/30 days)	$/kVA	0.69660	April 30, 2013
2012 ICM Rate Rider (per connection/30 days)	$/kVA	1.44390	April 30, 2015
Rate Rider for Deferral/Variance Account Disposition (2012) (per connection/30 days)	$/kVA	(0.45290)	April 30, 2013

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

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3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please enter your RTS-Network Rates from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus un the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells the correct classes exactly as it appears on the tariff.

Rate Description	Unit	Amount
Residential		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Residential Urban		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
General Service Less Than 50 kW		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728
General Service 50 to 999 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.60566
General Service 1,000 to 4,999 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.51749
Large Use > 5000 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.86985
Unmetered Scattered Load		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458
Sentinel Lighting		

Street Lighting		
Retail Transmission Rate – Network Service Rate	$/kW	2.31750
Standby - General Service 50 - 1,000 kW		
Standby - General Service 1,000 - 5,000 kW		
Standby - Large Use		

Ontario Energy Board

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Toronto Hydro-Electric System Limited - EB-2011-0144

Please enter your RTS-Connection Rates from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus unde the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells unde the correct classes exactly as it appears on the tariff.

Rate Description	Unit	Amount
Residential		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601
Residential Urban		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601
General Service Less Than 50 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542
General Service 50 to 999 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06482
General Service 1,000 to 4,999 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06283
Large Use > 5000 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.29168
Unmetered Scattered Load		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379
Sentinel Lighting		

Street Lighting		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.46209
Standby - General Service 50 - 1,000 kW		
Standby - General Service 1,000 - 5,000 kW		
Standby - Large Use		

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 and Account 1562. Enter information into green cells only. Lines 51-61 contain footnotes and further instructions.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December 31, 2009 balances, the starting point for your entries below should be the adjustment column AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

		2005									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [5]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-Account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**										
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

1 Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

2A Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

3 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

4 Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 and 29.

5 For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

6 If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31, 2011 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from January 1, 2011 to April 30, 11 on the December 31, 2010 balance. The projected interested is recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision.

7 Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has been completed, and the audited financial statements support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 49).

Toronto Hydro-Electric System Limited - EB-2011-0144

lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 ar
ootnotes and further instructions.

you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DV
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December
olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.

		2006									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [5]	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**										$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.
negative figure) as per the related Board decision.

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 a

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transac
If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31, 2
Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from Janua
recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances appr

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Toronto Hydro-Electric System Limited - EB-2011-0144

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otnotes and further instructions.

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olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [5]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	$ -				$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.
negative figure) as per the related Board decision.

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

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Toronto Hydro-Electric System Limited - EB-2011-0144

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ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

		2008									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [5]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	$ -				$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

Account Descriptions	Account Number	2009 Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [5]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	$ -				$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

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olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.

Account Descriptions	Account Number	2010 Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments [5]	Board-Approved Disposition during 2010	Other [3] Adjustments during Q1 2010	Other [3] Adjustments during Q2 2010	Other [3] Adjustments during Q3 2010	Other [3] Adjustments during Q4 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other [3]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts														
LV Variance Account	1550	$ -							$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -							$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -							$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -							$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -							$ -	$ -				$ -
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Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**								$ -					$ -
Deferred Payments in Lieu of Taxes	**1562**	$ -							$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592								$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592								$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -							$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -							$ -	$ -				$ -

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Toronto Hydro-Electric System Limited - EB-2011-0144

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		2011				Projected Interest on Dec-31-10 Balances			2.1.7 RRR	
Account Descriptions	Account Number	Principal Disposition during 2011 - instructed by Board	Interest Disposition during 2011 - instructed by Board	Closing Principal Balances as of Dec 31-10 Adjusted for Dispositions during 2011	Closing Interest Balances as of Dec 31-10 Adjusted during 2011 Disposition	Projected Interest from Jan 1, 2011 to December 31, 2011 on Dec 31 -10 balance adjusted for disposition during 2011 [5]	Projected Interest from January 1, 2012 to April 30, 2012 on Dec 31 -10 balance adjusted for disposition during 2011 [6, 7]	Total Claim	As of Dec 31-10 [4]	Variance RRR vs. 2010 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550			$ -	$ -			$ -		$ -
RSVA - Wholesale Market Service Charge	1580			$ -	$ -			$ -		$ -
RSVA - Retail Transmission Network Charge	1584			$ -	$ -			$ -		$ -
RSVA - Retail Transmission Connection Charge	1586			$ -	$ -			$ -		$ -
RSVA - Power (excluding Global Adjustment)	1588			$ -	$ -			$ -		$ -
RSVA - Power - Sub-Account - Global Adjustment	1588			$ -	$ -			$ -		$ -
Recovery of Regulatory Asset Balances	1590			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595			$ -	$ -			$ -		$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**							$ -		$ -
Deferred Payments in Lieu of Taxes	**1562**			$ -	$ -			$ -		$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:										
Board-Approved CDM Variance Account	1567							$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592							$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592							$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592							$ -		$ -
Disposition and Recovery of Regulatory Balances[7]	1595							$ -		$ -

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Ontario Energy Board

3RD Generation Incentive Regulation Model

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In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]
Residential	$/kWh				-				
Residential Urban	$/kWh				-				
General Service Less Than 50 kW	$/kWh				-				
General Service 50 to 999 kW	$/kWh				-				
General Service 1,000 to 4,999 kW	$/kWh				-				
Large Use > 5000 kW	$/kWh				-				
Unmetered Scattered Load	$/kWh				-				
Sentinel Lighting					-				
Street Lighting	$/kWh				-				
Standby - General Service 50 - 1,000 kW					-				
Standby - General Service 1,000 - 5,000 kW					-				
Standby - Large Use					-				
Total		-	-	-	-	-	0%	0%	0%

Total Claim (including Accounts 1521 and 1562)	$	-
Total Claim for Threshold Test (All Group 1 Accounts)	$	-
Threshold Test [3] (Total Claim per kWh)		

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balance.

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[3] The Threshold Test does not include the amount in 1521 nor 1562.

No input required. This worksheet allocates the deferral/variance account balances (Group 1, 1521, 1588 GA and 1562) to the appropriate classes.

Allocation of Group 1 Accounts (Excluding Account 1588 - Global Adjustment)

Rate Class	Units	Billed kWh	% kWh	1550	1580	1584	1586	1588*	1590	1595 (2008)	1595 (2009)	1521	Total
Residential	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Residential Urban	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
General Service Less Than 50 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
General Service 50 to 999 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
General Service 1,000 to 4,999 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Large Use > 5000 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Unmetered Scattered Load	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Sentinel Lighting	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Street Lighting	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - General Service 50 - 1,000 kW	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - General Service 1,000 - 5,000 kW	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - Large Use	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Total		-	0.00%	0	0	0	0	0	0	0	0	0	0

** RSVA - Power (Excluding Global Adjustment)*

1588 RSVA - Power (Global Adjustment Sub-Account)

Rate Class	non-RPP kWh	% kWh	1588
Residential	-	0.00%	-
Residential Urban	-	0.00%	-
General Service Less Than 50 kW	-	0.00%	-
General Service 50 to 999 kW	-	0.00%	-
General Service 1,000 to 4,999 kW	-	0.00%	-
Large Use > 5000 kW	-	0.00%	-
Unmetered Scattered Load	-	0.00%	-
Sentinel Lighting	-	0.00%	-
Street Lighting	-	0.00%	-
Standby - General Service 50 - 1,000 kW	-	0.00%	-
Standby - General Service 1,000 - 5,000 kW	-	0.00%	-
Standby - Large Use	-	0.00%	-
Total	0	0.00%	0

Allocation of Account 1562

	% of Distribution Revenue	Allocation of Balance in Account 1562
Residential	0.0%	-
Residential Urban	0.0%	-
General Service Less Than 50 kW	0.0%	-
General Service 50 to 999 kW	0.0%	-
General Service 1,000 to 4,999 kW	0.0%	-
Large Use > 5000 kW	0.0%	-
Unmetered Scattered Load	0.0%	-
Sentinel Lighting	0.0%	-
Street Lighting	0.0%	-
Standby - General Service 50 - 1,000 kW	0.0%	-
Standby - General Service 1,000 - 5,000 kW	0.0%	-
Standby - Large Use	0.0%	-
Total	0.0%	-

Ontario Energy Board

Deferral / Variance Account Work Form

Toronto Hydro-Electric System Limited - EB-2011-0144

No input required. This workshseet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and associated rate riders for the global adjustment sub-account.

Please indicate the Rate Rider Recovery Period (in years): 1

Rate Class	Unit	Billed kWh	Billed kW	Accounts Allocated by kWh/kW (RPP) or Distribution Revenue	Deferral/Variance Account Rate Rider	Account 1588 Global Adjustment	Billed kWh or Estimated kW for Non-RPP	Global Adjustment Rate Rider
Residential	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Residential Urban	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
General Service Less Than 50 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
General Service 50 to 999 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
General Service 1,000 to 4,999 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Large Use > 5000 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Unmetered Scattered Load	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Sentinel Lighting	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Street Lighting	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Standby - General Service 50 - 1,000 kW	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Standby - General Service 1,000 - 5,000 kW	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Standby - Large Use	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Total		-	-	$ -		$ -		

Toronto Hydro-Electric System Limited - EB-2011-0144

Below is a listing of the current Monthly Fixed Charges. All rates with expired effective dates have been removed. In columns "B", "K", and "M" (green cells), please enter all additional Monthly Fixed Charges you are proposing (eg: Smart Meter Funding Adder, etc). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable).

Rate Description	Unit	Amount	Effective Until Date	Proposed Amount	Effective Until Date
Residential					
Service Charge (Based on 30 day month)	$	18.37	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2014		
2012 ICM Rate Rider (per 30 days)	$	0.92	April 30, 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$			0.43	April 30 2014
2013 ICM Rate Rider (per 30 days)	$			1.23	April 30 2015
	$				
Residential Urban					
Service Charge (Based on 30 day month)	$	17.12	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2014		
2012 ICM Rate Rider (per 30 days)	$	0.34	April 30, 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$			0.16	April 30 2014
2013 ICM Rate Rider (per 30 days)	$			0.46	April 30 2015
	$				
General Service Less Than 50 kW					
Service Charge (Based on 30 day month)	$	24.47	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2014		
2012 ICM Rate Rider (per 30 days)	$	1.22	April 30, 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$			0.58	April 30 2014
2013 ICM Rate Rider (per 30 days)	$			1.64	April 30 2015
	$				
General Service 50 to 999 kW					
Service Charge (Based on 30 day month)	$	35.80	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2014		
2012 ICM Rate Rider (per 30 days)	$	1.79	April 30, 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$			0.84	April 30 2014
2013 ICM Rate Rider (per 30 days)	$			2.40	April 30 2015
	$				
General Service 1,000 to 4,999 kW					
Service Charge (Based on 30 day month)	$	691.13	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2014		
2012 ICM Rate Rider (per 30 days)	$	34.51	April 30, 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$			16.25	April 30 2014
2013 ICM Rate Rider (per 30 days)	$			46.34	April 30 2015
	$				
Large Use > 5000 kW					
Service Charge (Based on 30 day month)	$	3029.57	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2014		
2012 ICM Rate Rider (per 30 days)	$	151.26	April 30, 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$			71.22	April 30 2014
2013 ICM Rate Rider (per 30 days)	$			203.11	April 30 2015
	$				
Unmetered Scattered Load					
Service Charge (Based on 30 day month)	$	4.87	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	0.02	April 30, 2015		
2011 Unfunded Capex Rate Rider (per customer/30 days)	$			0.01	April 30 2014
2013 ICM Rate Rider (per customer/30 days)	$			0.03	April 30 2015
	$				
Sentinel Lighting					
Service Charge (per connection)	$	0.49	April 30, 2015		
2012 ICM Rate Rider (per connection/30 days)	$	0.24	April 30, 2015		
2011 Unfunded Capex Rate Rider (per connection/30 days)	$			0.11	April 30 2014
	$			0.33	April 30 2015
	$				
Street Lighting					
Service Charge (Based on 30 day month)	$	1.31	April 30, 2015		
2012 ICM Rate Rider (per connection/30 days)	$	0.07	April 30, 2015		
2011 Unfunded Capex Rate Rider (per connectio/30 days)	$			0.03	April 30 2014
2013 ICM Rate Rider (per connection/30 days)	$			0.09	April 30 2015
	$				
Standby - General Service 50 - 1,000 kW					
Service Charge (Based on 30 day month)	$	199.26	April 30, 2015		
	$				
	$				
	$				

Standby - General Service 1,000 - 5,000 kW					
Service Charge (Based on 30 day month)	$	199.26	April 30, 2015		
	$				
	$				
	$				
Standby - Large Use					
Service Charge (Based on 30 day month)	$	199.26	April 30, 2015		
	$				
	$				
	$				

Toronto Hydro-Electric System Limited - EB-2011-0144

Below is a listing of the current Distribution Volumetric Rates other than the base rates. All rates with expired effective dates have been removed. In columns "B", "K", and "M" (green cells), please enter all additional volumetric rates you are proposing (eg: LRAM/SSM, Tax Adjustments, etc.). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable).

Rate Description	Unit	Amount	Effective Until Date	Proposed Amount	Effective Until Date
Residential					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00077	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh			0.00036	April 30 2014
2013 ICM Rate Rider (per 30 days)	$/kWh			0.00103	April 30 2015
Residential Urban					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00131	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh			0.00062	April 30 2014
2013 ICM Rate Rider (per 30 days)	$/kWh			0.00176	April 30 2015
General Service Less Than 50 kW					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00115	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh			0.00054	April 30 2014
2013 ICM Rate Rider (per 30 days)	$/kWh			0.00154	April 30 2015
General Service 50 to 999 kW					
2012 ICM Rate Rider (per 30 days)	$/kVA	0.28130	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA			0.13240	April 30 2014
2013 ICM Rate Rider (per 30 days)	$/kVA			0.37770	April 30 2015
General Service 1,000 to 4,999 kW					
2012 ICM Rate Rider (per 30 days)	$/kVA	0.22370	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA			0.10530	April 30 2014
2013 ICM Rate Rider (per 30 days)	$/kVA			0.30030	April 30 2015
Large Use > 5000 kW					
2012 ICM Rate Rider (per 30 days)	$/kVA	0.23830	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA			0.11220	April 30 2014
2013 ICM Rate Rider (per 30 days)	$/kVA			0.32000	April 30 2015
Unmetered Scattered Load					
2012 ICM Rate Rider (per customer/30 days)	$/kWh	0.00309	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$/kWh			0.00146	April 30 2014
2013 ICM Rate Rider (per customer/30 days)	$/kWh			0.00415	April 30 2015

Sentinel Lighting

Street Lighting

2012 ICM Rate Rider (per connection/30 days)	$/kVA	1.44390	April 30, 2015		
Rate Rider for 2011 Unfunded Capex (per connection/30 days)	$/kVA			0.67980	April 30 2014
2013 ICM Rate Rider (per connection/30 days)	$/kVA			1.93890	April 30 2015

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Current RTSR-Network Rates are listed below. In column "K", please enter your proposed RTSR-Network Rates as per Sheet 13 of the Board's RTS Workform.

Rate Description	Unit	Current Amount	% Adjustment	Proposed Amount
Residential				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752	0.000%	0.00752
Residential Urban				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752	0.000%	0.00752
General Service Less Than 50 kW				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728	0.000%	0.00728
General Service 50 to 999 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.60566	0.000%	2.60566
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.51749	0.000%	2.51749
Large Use > 5000 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.86985	0.000%	2.86985
Unmetered Scattered Load				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458	0.000%	0.00458
Sentinel Lighting				
Street Lighting				
Retail Transmission Rate – Network Service Rate	$/kW	2.31750	0.000%	2.31750
Standby - General Service 50 - 1,000 kW				

Standby - General Service 1,000 - 5,000 kW		
Standby - Large Use		

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Current RTSR-Connection Rates are listed below. In column "K", please enter your proposed RTSR-Connection Rates as per Sheet 13 of the Board's RTSR Workform.

Rate Description	Unit	Current Amount	% Adjustment	Proposed Amount
Residential				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601	0.000%	0.00601
Residential Urban				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601	0.000%	0.00601
General Service Less Than 50 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542	0.000%	0.00542
General Service 50 to 999 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06482	0.000%	2.06482
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06283	0.000%	2.06283
Large Use > 5000 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.29168	0.000%	2.29168
Unmetered Scattered Load				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379	0.000%	0.00379
Sentinel Lighting				
Street Lighting				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.46209	0.000%	2.46209
Standby - General Service 50 - 1,000 kW				
Standby - General Service 1,000 - 5,000 kW				
Standby - Large Use				

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

If applicable, please enter any adjustments related to the revenue to cost ratio model into columns H and K.
The Price Escalator has been set at the 2011 values and will be updated by Board staff. The Stretch Factor Value will also be updated by Board staff.

Price Escalator	**2.00%**	**Productivity Factor**	**0.72%**	**Price Cap Index**	**0.68%**
Choose Stretch Factor Group	III	**Associated Stretch Factor Value**	**0.6%**		

Rate Description	Unit	Current MFC	MFC Adjustment from R/C Model	Current Volumetric Charge	Unit	DVR Adjustment from R/C Model	Price Cap Index	Proposed MFC	Proposed Volumetric Charge
Residential	$	18.37		0.01518	$/kWh		0.680%	18.50	0.01528
Residential Urban	$	17.12		0.02582	$/kWh		0.680%	17.23	0.02600
General Service Less Than 50 kW	$	24.47		0.02262	$/kWh		0.680%	24.63	0.02278
General Service 50 to 999 kW	$	35.80		5.63365	$/kVA		0.680%	36.05	5.67196
General Service 1,000 to 4,999 kW	$	691.13		4.47996	$/kVA		0.680%	695.83	4.51042
Large Use > 5000 kW	$	3,029.57		4.77284	$/kVA		0.680%	3,050.17	4.80529
Unmetered Scattered Load	$	4.87		0.06111	$/kWh		0.680%	4.91	0.06153
Sentinel Lighting	$	0.49					0.680%	0.50	
Street Lighting	$	1.31		28.92013	$/kVA		0.680%	1.32	29.11679
Standby - General Service 50 - 1,000 kW	$	199.26		5.63365	$/kVA		0.680%	200.61	5.67196
Standby - General Service 1,000 - 5,000 kW	$	199.26		4.47996	$/kVA		0.680%	200.61	4.51042
Standby - Large Use	$	199.26		4.77284	$/kVA		0.680%	200.61	4.80529

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please enter the descriptions of the current Loss Factors from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menu in the column labeled "Loss Factors". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct classes.

Loss Factors	Current
Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0376
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.1087
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0272
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0085

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

The standard Allowance rates have been included as default entries. If you have different rates, please make the appropriate corrections in the below. As well, please enter the current Specific Service Charges below. The standard Retail Service Charges have been entered below. If you rates, please make the appropriate corrections in columns B, D or E as applicable (cells are unlocked).

ALLOWANCES

	UNIT	CURRENT
Transformer Allowance for Ownership - per kVA of billing demand/30 days	$/kVA	(0.62)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

	UNIT	CURRENT
Duplicate invoices for previous billing	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Request for other billing information	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month		%	1.50
Late Payment - per annum		%	19.56
Collection of account charge - no disconnection		$	30.00
Disconnect/Reconnect at meter - during regular hours		$	65.00
Disconnect/Reconnect at meter - after regular hours		$	185.00
Disconnect/Reconnect at pole - during regular hours		$	185.00
Disconnect/Reconnect at pole - after regular hours	**/C**	$	415.00

Other

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Specific Charge for Access to the Power Poles $/pole/year	$	18.55
Specific Charge for Access to the Power Poles $/pole/year	$	-22.75

Residential	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	18.37	18.37	1	18.50	18.50	0.13	0.7%
Distribution	800	0.01518	12.14	800	0.01528	12.22	0.08	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	0.24	0.24	-	-	-	(0.24)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.44	0.44	1	0.43	0.43	(0.01)	-2.3%
2011 Unfunded Capex Rate Rider - DVR	800	0.00037	0.30	800	0.00036	0.29	(0.01)	-2.7%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	0.92	0.92	1	0.92	0.92	-	0.0%
2012 ICM Rate Rider - DVR	800	0.00077	0.62	800	0.00077	0.62	-	0.0%
2013 ICM Rate Rider - MFC	-	-	-	1	1.23	1.23	1.23	n/a
2013 ICM Rate Rider - DVR	-	-	-	800	0.00103	0.82	0.82	n/a
Deferral/Variance Account Rate Rider	800	(0.00050)	(0.40)	-	-	-	0.40	-100.0%
Sub Total A - Distribution			33.31			35.71	2.41	7.2%
RTST - Network	830.08	0.00752	6.24	830.08	0.00752	6.24	-	0.0%
RTSR - Connection	830.08	0.00601	4.99	830.08	0.00601	4.99	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			44.54			46.94	2.41	5.4%
Wholesale Market Rate	830	0.00520	4.32	830	0.00520	4.32	-	0.0%
RRRP (May 1, 2012)	830	0.00110	0.91	830	0.00110	0.91	-	0.0%
DRC	800	0.00700	5.60	800	0.00700	5.60	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	830	-	-	830	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	600	0.075	45.00	600	0.075	45.00	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	230	0.088	20.25	230	0.088	20.25	-	0.0%
Total Bill (including Sub-Total B)			120.86			123.27	2.41	2.0%

	kWh
Consumption Details	**800**
Total Loss Factor	1.0376

Competitive Sector Multi-Unit Residential	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	17.12	17.12	1	17.23	17.23	0.11	0.6%
Distribution	334	0.02582	8.62	334	0.02600	8.68	0.06	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	0.24	0.24	-	-	-	(0.24)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.17	0.17	1	0.16	0.16	(0.01)	-5.9%
2011 Unfunded Capex Rate Rider - DVR	334	0.00063	0.21	334	0.00062	0.21	(0.00)	-1.6%
Shared Tax Savings Rate Rider - DVR	334	(0.00010)	(0.03)	-	-	-	0.03	-100.0%
2012 ICM Rate Rider - MFC	1	0.34	0.34	1	0.34	0.34	-	0.0%
2012 ICM Rate Rider - DVR	334	0.00131	0.44	334	0.00131	0.44	-	0.0%
2013 ICM Rate Rider - MFC	-	-	-	1	0.46000	0.46	0.46	n/a
2013 ICM Rate Rider - DVR	-	-	-	334	0.00176	0.59	0.59	n/a
Deferral/Variance Account Rate Rider	334	(0.00056)	(0.19)	-	-	-	0.19	-100.0%
Sub Total A - Distribution			27.60			28.79	1.19	4.3%
RTST - Network	346.56	0.00752	2.61	346.56	0.00752	2.61	-	0.0%
RTSR - Connection	346.56	0.00601	2.08	346.56	0.00601	2.08	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			32.29			33.48	1.19	3.7%
Wholesale Market Rate	347	0.00520	1.80	347	0.00520	1.80	-	0.0%
RRRP (May 1, 2012)	347	0.00110	0.38	347	0.00110	0.38	-	0.0%
DRC	334	0.00700	2.34	334	0.00700	2.34	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	347	-	-	347	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	347	0.075	25.99	347	0.075	25.99	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	-	0.088	-	-	0.088	-	-	n/a
Total Bill (including Sub-Total B)			63.05			64.24	1.19	1.9%

	kWh
Consumption Details	**334**
Total Loss Factor	1.0376

GS < 50 kW	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	24.47	24.47	1	24.63	24.63	0.16	0.7%
Distribution	2,000	0.02262	45.24	2,000	0.02278	45.56	0.32	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	0.69	0.69	-	-	-	(0.69)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.59	0.59	1	0.58	0.58	(0.01)	-1.7%
2011 Unfunded Capex Rate Rider - DVR	2,000	0.00055	1.10	2,000	0.00054	1.08	(0.02)	-1.8%
Shared Tax Savings Rate Rider - DVR	2,000	-	-	2,000	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	1.22	1.22	1	1.22	1.22	-	0.0%
2012 ICM Rate Rider - DVR	2,000	0.00115	2.30	2,000	0.00115	2.30	-	0.0%
2013 ICM Rate Rider - MFC	-	-	-	1	1.64	1.64	1.64	n/a
2013 ICM Rate Rider - DVR	-	-	-	2,000	0.00154	3.08	3.08	n/a
Deferral/Variance Account Rate Rider	2,000	(0.00037)	(0.74)	-	-	-	0.74	-100.0%
Sub Total A - Distribution			75.55			80.77	5.22	6.9%
RTST - Network	2,075	0.00728	15.11	2,075	0.00728	15.11	-	0.0%
RTSR - Connection	2,075	0.00542	11.25	2,075	0.00542	11.25	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			101.91			107.13	5.22	5.1%
Wholesale Market Rate	2,075	0.0052	10.79	2,075	0.0052	10.79	-	0.0%
RRRP (May 1, 2012)	2,075	0.00110	2.28	2,075	0.00110	2.28	-	0.0%
DRC	2,000	0.0070	14.00	2,000	0.0070	14.00	-	0.0%
Standard Supply Service Charge	1.00	0.25	0.25	1.00	0.25	0.25	-	0.0%
Special Purpose Charge	2,075	-	-	2,075	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	1,325	0.088	116.62	1,325	0.088	116.62	-	0.0%
Total Bill (including Sub-Total B)			302.10			307.32	5.22	1.7%

	kWh
Consumption Details	**2,000.00**
Total Loss Factor	1.0376

GS > 50 < 1000	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	35.80	35.80	1	36.05	36.05	0.25	0.7%
Distribution	388	5.6337	2,185.88	388	5.6720	2,200.74	14.86	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - Global Adjustment - Non RPP	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	8.37	8.37	-	-	-	(8.37)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.86	0.86	1	0.84	0.84	(0.02)	-2.3%
2011 Unfunded Capex Rate Rider - DVR	388	0.1357	52.65	388	0.1324	51.37	(1.28)	-2.4%
Shared Tax Savings Rate Rider - DVR	388	(0.0067)	(2.60)	-	-	-	2.60	-100.0%
2012 ICM Rate Rider - MFC	1	1.79	1.79	1	1.79	1.79	-	0.0%
2012 ICM Rate Rider - DVR	388	0.2813	109.14	388	0.2813	109.14	-	0.0%
2013 ICM Rate Rider - MFC	-	-	-	1	2.40	2.40	2.40	n/a
2013 ICM Rate Rider - DVR	-	-	-	388	0.3777	146.55	146.55	n/a
Deferral/Variance Account Rate Rider	388	(0.00020)	(0.08)	-	-	-	0.08	-100.0%
Sub Total A - Distribution			2,392.49			2,549.56	157.06	6.6%
RTST - Network	349	2.6057	909.39	349	2.6057	909.39	-	0.0%
RTSR - Connection	349	2.0648	720.62	349	2.0648	720.62	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			4,022.50			4,179.56	157.06	3.9%
Wholesale Market Rate	155,640	0.0052	809.33	155,640	0.0052	809.33	-	0.0%
RRRP (May 1, 2012)	155,640	0.00110	171.20	155,640	0.00110	171.20	-	0.0%
DRC	150,000	0.0070	1,050.00	150,000	0.0070	1,050.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	155,640	-	-	155,640	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	154,890	0.088	13,630.32	154,890	0.088	13,630.32	-	0.0%
Total Bill (including Sub-Total B)			19,739.85			19,896.92	157.06	0.8%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	150,000	349	388	430	90%	100%
Total Loss Factor	1.0376					

GS > 1000 < 5000	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	691.13	691.13	1	695.83	695.83	4.70	0.7%
Distribution	1,778	4.4800	7,965.44	1,778	4.5104	8,019.49	54.05	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - Global Adjustment - Non RPP	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1.00	69.81	69.81	-	-	-	(69.81)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	16.65	16.65	1	16.25	16.25	(0.40)	-2.4%
2011 Unfunded Capex Rate Rider - DVR	1,778	0.10790	191.85	1,778	0.10530	187.22	(4.62)	-2.4%
Shared Tax Savings Rate Rider - DVR	1,778	(0.00560)	(9.96)	-	-	-	9.96	-100.0%
2012 ICM Rate Rider - MFC	1	34.51	34.51	1	34.51	34.51	-	0.0%
2012 ICM Rate Rider - DVR	1,778	0.22370	397.74	1,778	0.22370	397.74	-	0.0%
2013 ICM Rate Rider - MFC	-	-	-	1	46.34	46.34	46.34	n/a
2013 ICM Rate Rider - DVR	-	-	-	1,778	0.30030	533.93	533.93	n/a
Deferral/Variance Account Rate Rider	1,778	(0.05080)	(90.32)	-	-	-	90.32	-100.0%
Sub Total A - Distribution			9,267.53			9,932.00	664.47	7.2%
RTST - Network	1,600	2.5175	4,028.00	1,600	2.5175	4,028.00	-	0.0%
RTSR - Connection	1,600	2.0628	3,300.48	1,600	2.0628	3,300.48	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			16,596.01			17,260.48	664.47	4.0%
Wholesale Market Rate	830,080	0.0052	4,316.42	830,080	0.0052	4,316.42	-	0.0%
RRRP (May 1, 2012)	830,080	0.00110	913.09	830,080	0.00110	913.09	-	0.0%
DRC	800,000	0.0070	5,600.00	800,000	0.0070	5,600.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	830,080	-	-	830,080	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	829,330	0.088	72,981.04	829,330	0.088	72,981.04	-	0.0%
Total Bill (including Sub-Total B)			100,463.05			101,127.52	664.47	0.7%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	800,000	1,600	1,778	500	90%	100%
Total Loss Factor	1.0376					

LU	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	3,029.57	3,029.57	1	3,050.17	3,050.17	20.60	0.7%
Distribution	9,434	4.7728	45,026.60	9,434	4.8053	45,333.20	306.60	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - Global Adjustment - Non RPP	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	304.62	304.62	-	-	-	(304.62)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	72.98	72.98	1	71.22	71.22	(1.76)	-2.4%
2011 Unfunded Capex Rate Rider - DVR	9,434	0.1150	1,084.91	9,434	0.1122	1,058.49	(26.42)	-2.4%
Shared Tax Savings Rate Rider - DVR	9,434	(0.0059)	(55.66)	-	-	-	55.66	-100.0%
2012 ICM Rate Rider - MFC	1	151.26	151.26	1	151.26	151.26	-	0.0%
2012 ICM Rate Rider - DVR	9,434	0.2383	2,248.12	9,434	0.2383	2,248.12	-	0.0%
2013 ICM Rate Rider - MFC	-	-	-	1	203.11	203.11	203.11	n/a
2013 ICM Rate Rider - DVR	-	-	-	9,434	0.3200	3,018.88	3,018.88	n/a
Deferral/Variance Account Rate Rider	9,434	(0.05280)	(498.12)	-	-	-	498.12	-100.0%
Sub Total A - Distribution			51,364.96			55,135.14	3,770.18	7.3%
RTST - Network	8,491	2.8699	24,368.32	8,491	2.8699	24,368.32	-	0.0%
RTSR - Connection	8,491	2.2917	19,458.82	8,491	2.2917	19,458.82	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			95,192.11			98,962.28	3,770.18	4.0%
Wholesale Market Rate	4,584,150	0.0052	23,837.58	4,584,150	0.0052	23,837.58	-	0.0%
RRRP (May 1, 2012)	4,584,150	0.00110	5,042.57	4,584,150	0.00110	5,042.57	-	0.0%
DRC	4,500,000	0.0070	31,500.00	4,500,000	0.0070	31,500.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	4,584,150	-	-	4,584,150	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	4,583,400	0.088	403,339.20	4,583,400	0.088	403,339.20	-	0.0%
Total Bill (including Sub-Total B)			558,967.95			562,738.13	3,770.18	0.7%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	4,500,000	8,491	9,434	530	90%	100%
Total Loss Factor	1.0187					

Street Lights	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Connection Charge	162,353	1.31	212,682.97	162,353	1.32	214,306.51	1,623.53	0.8%
Distribution	25,755	28.9201	744,837.18	25,755	29.1168	749,903.18	5,066.01	0.7%
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	162,353	0.04	6,494.14	-	-	-	(6,494.14)	-100.0%
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	162,353.42	0.03	4,870.60	162,353.42	0.03	4,870.60	-	0.0%
2011 Unfunded Capex Rate Rider - DVR	25,755.00	0.6966	17,940.93	25,755.00	0.6798	17,508.25	(432.68)	-2.4%
Shared Tax Savings Rate Rider - DVR	25,755.00	(0.0425)	(1,094.59)	-	-	-	1,094.59	-100.0%
2012 ICM Rate Rider - MFC	162,353.42	0.07	11,364.74	162,353.42	0.07	11,364.74	-	0.0%
2012 ICM Rate Rider - DVR	25,755.00	1.4439	37,187.64	25,755.00	1.4439	37,187.64	-	0.0%
2013 ICM Rate Rider - MFC			-	162,353.42	0.09	14,611.81	14,611.81	n/a
2013 ICM Rate Rider - DVR			-	25,755.00	1.9389	49,936.37	49,936.37	n/a
Deferral/Variance Account Rate Rider	25,755.00	(0.45290)	(11,664.44)	-	-	-	11,664.44	-100.0%
Sub Total A - Distribution			1,022,619.18			1,099,689.11	77,069.93	7.5%
RTST - Network	25,755	2.3175	59,687.21	25,755	2.3175	59,687.21	-	0.0%
RTSR - Connection	25,755	2.4621	63,411.39	25,755	2.4621	63,411.39	-	0.0%
Sub Total B (including Sub-Total A) - Distribution		-	1,145,717.78		-	1,222,787.70	77,069.93	6.7%
Wholesale Market Rate	9,620,365	0.0052	50,025.90	9,620,365	0.0052	50,025.90	-	0.0%
RRRP (May 1, 2012)	9,620,365	0.00110	10,582.40	9,620,365	0.00110	10,582.40	-	0.0%
DRC	9,271,748	0.0070	64,902.23	9,271,748	0.0070	64,902.23	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	9,620,365	-	-	9,620,365	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	9,619,615	0.088	846,526.14	9,619,615	0.088	846,526.14	-	0.0%
Total Bill (including Sub-Total B)			2,117,810.95			2,194,880.87	77,069.93	3.6%

	kWh	Connections	**PF**	KVA	**Hours Use**	**PF**	**Net/Conn**
Consumption Details	9,271,747.50	162,353	100%	1.00	360	100%	100%
Total Loss Factor	1.0376						

USL	2012			2013			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	4.87	4.87	1	4.91	4.91	0.04	0.8%
Connection Charge	1	0.49	0.49	1	0.50	0.50	0.01	2.0%
Distribution	365	0.06111	22.31	365	0.06153	22.46	0.15	0.7%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	1	0.09	0.09	-	-	-	(0.09)	-100.0%
Foregone Revenue Rate Rider - fixed rate - customer	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate - connection	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.01	0.01	1	0.01	0.01	-	0.0%
2011 Unfunded Capex Rate Rider - MFC (Connection)	1	0.12	0.12	1	0.11	0.11	(0.01)	-8.3%
2011 Unfunded Capex Rate Rider - DVR	365	0.00149	0.54	365	0.00146	0.53	(0.01)	-2.0%
Shared Tax Savings Rate Rider - DVR	365	(0.00010)	(0.04)	-	-	-	0.04	-100.0%
2012 ICM Rate Rider - MFC	1	0.02	0.02	1	0.02	0.02	-	0.0%
2012 ICM Rate Rider - MFC (Connection)	1	0.24	0.24	1	0.24	0.24	-	0.0%
2012 ICM Rate Rider - DVR	365	0.00309	1.13	365	0.00309	1.13	(0.00)	-0.1%
2013 ICM Rate Rider - MFC	-	-	-	1	0.030	0.03	0.03	n/a
2013 ICM Rate Rider - MFC (Connection)	-	-	-	1	0.330	0.33	0.33	n/a
2013 ICM Rate Rider - DVR	-	-	-	365	0.00415	1.51	1.51	n/a
Deferral/Variance Account Rate Rider	365	(0.00102)	(0.37)	-	-	-	0.37	-100.0%
Sub Total A - Distribution			29.41			31.78	2.37	8.1%
RTST - Network	379	0.00458	1.73	379	0.00458	1.73	-	0.0%
RTSR - Connection	379	0.00379	1.44	379	0.00379	1.44	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			32.58			34.95	2.37	7.3%
Wholesale Market Rate	379	0.00520	1.97	379	0.00520	1.97	-	0.0%
RRRP (May 1, 2012)	379	0.00110	0.42	379	0.00110	0.42	-	0.0%
DRC	365	0.00700	2.56	365	0.00700	2.56	-	0.0%
Standard Supply Service Charge	1	0.25000	0.25	1	0.25000	0.25	-	0.0%
Special Purpose Charge	-	-	-	-	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	379	0.075	28.40	379	0.075	28.40	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	-	0.088	-	-	0.088	-	-	n/a
Total Bill (including Sub-Total B)			66.17			68.55	2.37	3.6%

	Kwh	Customer	Connection
Consumption Details	365	1	1
Total Loss Factor	1.0376		

V1.4

Ontario Energy Board

3RD Generation Incentive Regulation Model

Choose Your Utility:

Toronto Hydro-Electric System Limited
Wasaga Distribution Inc.

Application Type: IRM3
OEB Application #: EB-2011-0144
LDC Licence #: ED-2002-0497

Application Contact Information

Name:	Anthony Lam
Title:	Economist
Phone Number:	416 542 2876
Email Address:	alam@torontohydro.com
We are applying for rates effective:	May 1, 2014
Please indicate the version of Microsoft Excel that you are currently using:	Excel 2007

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION FIELD

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

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Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges.
Note: The microFIT class does not exist in the drop-down menu below as it will automatically be inserted into your proposed Tariff Schedule.

Rate Class

Residential
Residential Urban
General Service Less Than 50 kW
General Service 50 to 999 kW
General Service 1,000 to 4,999 kW
Large Use > 5000 kW
Standby - General Service 50 - 1,000 kW
Standby - General Service 1,000 - 5,000 kW
Standby - Large Use
Unmetered Scattered Load
Street Lighting
Sentinel Lighting
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class
Choose Rate Class

Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Please note that unlike the Distribution Volumetric Rates, which will be entered in the following two tabs, all current Monthly Fixed Charges, including the base charges, must be entered on this tab. Please enter the descriptions of the current Monthly Fix Charges exactly as they appear on your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct class exactly as it appears on the tariff. Once a description is selected or entered into the green cells, the input cells for the "Unit", "Amount", and "Effective Date" will appear. Please note that the base Monthly Fixed Charge is identified in the drop-down list as a "Service Charge" to coincide with the description on the tariff. Please do not enter more than one "Service Charge" for each class for which a base monthly fixed charge applies. **Note: Do not enter Standard Supply Service Rate. The rate will appear automatically on the final Tariff of Rates and Charges.

Rate Description	Unit	Amount	Effective Until Date
Residential			
Service Charge (Based on 30 day month)	$	18.50	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	0.92	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	1.23	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.43	April 30 2014
Residential Urban			
Service Charge (Based on 30 day month)	$	17.23	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	0.34	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	0.46	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.16	April 30 2014
General Service Less Than 50 kW			
Service Charge (Based on 30 day month)	$	24.63	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	1.22	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	1.64	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.58	April 30 2014
General Service 50 to 999 kW			
Service Charge (Based on 30 day month)	$	36.05	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	1.79	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	2.40	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.84	April 30 2014
General Service 1,000 to 4,999 kW			
Service Charge (Based on 30 day month)	$	695.83	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	34.51	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	46.34	April 30 2015

2011 Unfunded Capex Rate Rider (per 30 days)	$	16.25	April 30 2014
Large Use > 5000 kW			
Service Charge (Based on 30 day month)	$	3050.17	April 30, 2015
Smart Meter Funding Adder	$	0.68	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	151.26	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	203.11	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	71.22	April 30 2014
Unmetered Scattered Load			
Service Charge (Based on 30 day month)	$	4.91	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	0.02	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	0.03	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.01	April 30 2014
Sentinel Lighting			
Service Charge (per connection)	$	0.50	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	0.24	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	0.33	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.11	April 30 2014
Street Lighting			
Service Charge (Based on 30 day month)	$	1.32	April 30, 2015
2012 ICM Rate Rider (per 30 days)	$	0.07	April 30 2015
2013 ICM Rate Rider (per 30 days)	$	0.09	April 30 2015
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.03	April 30 2014
Standby - General Service 50 - 1,000 kW			
Service Charge (Based on 30 day month)	$	200.61	April 30, 2015
Standby - General Service 1,000 - 5,000 kW			
Service Charge (Based on 30 day month)	$	200.61	April 30, 2015
Standby - Large Use			
Service Charge (Based on 30 day month)	$	200.61	April 30, 2015

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For each class, please enter the base Distribution Volumetric Rates ("DVR") from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus and input cells in columns labeled "Unit" and "Amount".

Rate Description	Unit	Amount
Residential	$/kWh	0.01528
Residential Urban	$/kWh	0.02600
General Service Less Than 50 kW	$/kWh	0.02278
General Service 50 to 999 kW	$/kVA	5.67196
General Service 1,000 to 4,999 kW	$/kVA	4.51042
Large Use > 5000 kW	$/kVA	4.80529
Unmetered Scattered Load	$/kWh	0.06153
Sentinel Lighting		
Street Lighting	$/kVA	29.11679
Standby - General Service 50 - 1,000 kW	$/kVA	5.67196
Standby - General Service 1,000 - 5,000 kW	$/kVA	4.51042
Standby - Large Use	$/kVA	4.80529

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Please enter the descriptions of all other current Variable Rates, <u>including</u> any applicable low voltage charges, rate riders, rate adders, etc. from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus located under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description of the associated rate in the green cells <u>exactly</u> as it appears on the tariff. Once a description is selected or entered into the green cells, the input cells for the "Unit", "Amount", and "Effective Date" will appear. **Note: Do not enter the WMSR or RRRP Rate below. These rates will appear automatically on the final Tariff of Rates and Charges.

Rate Description	Unit	Amount	Effective Until Date
Residential			
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00077	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00103	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00036	April 30 2014
Residential Urban			
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00131	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00176	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00062	April 30 2014
General Service Less Than 50 kW			
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00115	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00154	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00054	April 30 2014
General Service 50 to 999 kW			

2012 ICM Rate Rider (per 30 days)	$/kVA	0.28130	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kVA	0.37770	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.13240	April 30 2014

General Service 1,000 to 4,999 kW

2012 ICM Rate Rider (per 30 days)	$/kVA	0.22370	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kVA	0.30030	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.10530	April 30 2014

Large Use > 5000 kW

2012 ICM Rate Rider (per 30 days)	$/kVA	0.23830	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kVA	0.32000	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.11220	April 30 2014

Unmetered Scattered Load

2012 ICM Rate Rider (per 30 days)	$/kWh	0.00309	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00415	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00146	April 30 2014

Sentinel Lighting

Street Lighting

2012 ICM Rate Rider (per 30 days)	$/kVA	1.44390	April 30 2015
2013 ICM Rate Rider (per 30 days)	$/kVA	1.93890	April 30 2015
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.67980	April 30 2014

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

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Please enter your RTS-Network Rates from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct classes exactly as it appears on the tariff.

Rate Description	Unit	Amount
Residential		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
Residential Urban		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752
General Service Less Than 50 kW		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728
General Service 50 to 999 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.60566
General Service 1,000 to 4,999 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.51749
Large Use > 5000 kW		
Retail Transmission Rate – Network Service Rate	$/kW	2.86985
Unmetered Scattered Load		
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458
Sentinel Lighting		
Street Lighting		
Retail Transmission Rate – Network Service Rate	$/kW	2.31750

Standby - General Service 50 - 1,000 kW

Standby - General Service 1,000 - 5,000 kW

Standby - Large Use

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Please enter your RTS-Connection Rates from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menus under the column labeled "Rate Description". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct classes <u>exactly</u> as it appears on the tariff.

Rate Description	Unit	Amount
Residential		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601
Residential Urban		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601
General Service Less Than 50 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542
General Service 50 to 999 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06482
General Service 1,000 to 4,999 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06283
Large Use > 5000 kW		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.29168
Unmetered Scattered Load		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379
Sentinel Lighting		
Street Lighting		
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.46209
Standby - General Service 50 - 1,000 kW		
Standby - General Service 1,000 - 5,000 kW		
Standby - Large Use		

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Please complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 and Account 1562. Enter information into green cells only. Lines 51-61 contain footnotes and further instructions.

If you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DVA schedule below will be the balance sheet date as per your G/L for which you received approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December 31, 2009 balances, the starting point for your entries below should be the adjustment column AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 opening balance columns (for both principal and interest) without requiring entries dating back to the beginning of the continuity schedule ie: Jan 1, 2005.

		2005									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-05	Transactions Debit / (Credit) during 2005 excluding interest and adjustments [5]	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec-31-05	Board-Approved Disposition during 2005	Adjustments during 2005 - other [3]	Closing Interest Amounts as of Dec-31-05
Group 1 Accounts											
LV Variance Account	1550					$ -					$ -
RSVA - Wholesale Market Service Charge	1580					$ -					$ -
RSVA - Retail Transmission Network Charge	1584					$ -					$ -
RSVA - Retail Transmission Connection Charge	1586					$ -					$ -
RSVA - Power (excluding Global Adjustment)	1588					$ -					$ -
RSVA - Power - Sub-Account - Global Adjustment	1588					$ -					$ -
Recovery of Regulatory Asset Balances	1590					$ -					$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595					$ -					$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595					$ -					$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**										
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592					$ -					$ -
Disposition and Recovery of Regulatory Balances[7]	1595					$ -					$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative figure) as per the related Board decision.

[1] Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, etc.

[2A] Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the 2006 EDR and account 1595 during the 2008 EDR and subsequent years as ordered by the Board.

[3] Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

[4] Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 and 29.

[5] For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transactions during the year.

[6] If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31, 2011 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from January 1, 2011 to April 30, 11 on the December 31, 2010 balance. The projected interested is recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances approved by the Board in the 2011 rate decision.

[7] Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has been completed, and the audited financial statements support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, include the balances in Account 1595 on a memo basis only (line 49).

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**lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 ar
otnotes and further instructions.**

**you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DV/
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December
olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

Account Descriptions	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions Debit / (Credit) during 2006 excluding interest and adjustments [5]	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec-31-06	Board-Approved Disposition during 2006 [2, 2A]	Adjustments during 2006 - other [3]	Closing Interest Amounts as of Dec-31-06
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**										$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

**For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g
negative figure) as per the related Board decision.**

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 ar

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transac
If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31, 2
Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from Janua
recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances appr

Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has
support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, incluc

**lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 ar
otnotes and further instructions.**

**you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DV/
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December
olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

Account Descriptions	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions Debit / (Credit) during 2007 excluding interest and adjustments [5]	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec-31-07	Board-Approved Disposition during 2007	Adjustments during 2007 - other [3]	Closing Interest Amounts as of Dec-31-07
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	$ -				$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

**For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.
negative figure) as per the related Board decision.**

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 ar

For RSVA accounts only, report the net variance to the account during the year. For all other accounts, record the transac
If the LDC's 2011 rate year started January 1, the projected interest is recorded from January 1, 2011 to December 31, 2
Board in the 2011 rate decision. If the LDC's 2011 rate year started May 1, the projected interest is recorded from Janua
recorded from May 1, 2011 to April 30, 2012 on the December 31, 2010 balance adjusted for the disposed balances appr

Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has
support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, incluc

Toronto Hydro-Electric System Limited - EB-2011-0144

**lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 ar
ootnotes and further instructions.**

**you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DVA
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December
olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

		2008									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions Debit / (Credit) during 2008 excluding interest and adjustments [5]	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec-31-08	Board-Approved Disposition during 2008	Adjustments during 2008 - other [3]	Closing Interest Amounts as of Dec-31-08
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008) [7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009) [7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	$ -				$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances [7]	1595	$ -				$ -	$ -				$ -

**For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.
negative figure) as per the related Board decision.**

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously Board Approved dis

Although the Global Adjustment Account is not reported separately under 2.1.7, please provide a breakdown in rows 28 a

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Include Account 1595 as part of Group 1 accounts (line 31) for review and disposition if the recovery (or refund) period has
support the underlying residual balance in account 1595. If the recovery (or refund) period has not been completed, incluc

Toronto Hydro-Electric System Limited - EB-2011-0144

lease complete the following continuity schedule for your Group 1 Deferral / Variance Accounts, Account 1521 ar
otnotes and further instructions.

you have received approval to dispose of balances from prior years, the starting point for entries in the 2012 DV/
eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December
olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.

		2009										
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-09	Transactions Debit / (Credit) during 2009 excluding interest and adjustments [5]	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Principal Balance as of Dec-31-09	Opening Interest Amounts as of Jan-1-09	Interest Jan-1 to Dec-31-09	Board-Approved Disposition during 2009	Adjustments during 2009 - other [3]	Closing Interest Amounts as of Dec-31-09
Group 1 Accounts											
LV Variance Account	1550	$ -				$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -				$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -				$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -				$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -				$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -				$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**										
Deferred Payments in Lieu of Taxes	**1562**	$ -				$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:											
Board-Approved CDM Variance Account	1567										
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592										
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -				$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -				$ -	$ -				$ -

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.
negative figure) as per the related Board decision.

Applicants may wish to propose kWh as the allocator for account 1521 pending a final decision of the Board

Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs wr

Adjustments Instructed by the Board include deferral/variance account balances moved to Account 1590 as a result of the

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Toronto Hydro-Electric System Limited - EB-2011-0144

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eceived approval. For example, if in the 2011 EDR process (CoS or IRM) you received approval for the December
olumn AV for principal and column BA for interest. This will allow for the correct starting point for the 2010 open
ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

		2010												
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-10	Transactions Debit / (Credit) during 2010 excluding interest and adjustments[5]	Board-Approved Disposition during 2010	Other[3] Adjustments during Q1 2010	Other[3] Adjustments during Q2 2010	Other[3] Adjustments during Q3 2010	Other[3] Adjustments during Q4 2010	Closing Principal Balance as of Dec-31-10	Opening Interest Amounts as of Jan-1-10	Interest Jan-1 to Dec-31-10	Board-Approved Disposition during 2010	Adjustments during 2010 - other[3]	Closing Interest Amounts as of Dec-31-10
Group 1 Accounts														
LV Variance Account	1550	$ -							$ -	$ -				$ -
RSVA - Wholesale Market Service Charge	1580	$ -							$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ -							$ -	$ -				$ -
RSVA - Retail Transmission Connection Charge	1586	$ -							$ -	$ -				$ -
RSVA - Power (excluding Global Adjustment)	1588	$ -							$ -	$ -				$ -
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -							$ -	$ -				$ -
Recovery of Regulatory Asset Balances	1590	$ -							$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595	$ -							$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595	$ -							$ -	$ -				$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**								$ -					$ -
Deferred Payments in Lieu of Taxes	**1562**	$ -							$ -	$ -				$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
The following is not included in the total claim but are included on a memo basis:														
Board-Approved CDM Variance Account	1567								$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592								$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592								$ -	$ -				$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592	$ -							$ -	$ -				$ -
Disposition and Recovery of Regulatory Balances[7]	1595	$ -							$ -	$ -				$ -

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Toronto Hydro-Electric System Limited - EB-2011-0144

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ack to the beginning of the continuity schedule ie: Jan 1, 2005.**

Account Descriptions	Account Number	2011 Principal Disposition during 2011 - instructed by Board	2011 Interest Disposition during 2011 - instructed by Board	2011 Closing Principal Balances as of Dec 31-10 Adjusted for Dispositions during 2011	2011 Closing Interest Balances as of Dec 31-10 Adjusted during 2011 Disposition	Projected Interest on Dec-31-10 Balances: Projected Interest from Jan 1, 2011 to December 31, 2011 on Dec 31 -10 balance adjusted for disposition during 2011 [5]	Projected Interest on Dec-31-10 Balances: Projected Interest from January 1, 2012 to April 30, 2012 on Dec 31 -10 balance adjusted for disposition during 2011 [6, 7]	Total Claim	2.1.7 RRR As of Dec 31-10 [4]	Variance RRR vs. 2010 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550			$ -	$ -			$ -		$ -
RSVA - Wholesale Market Service Charge	1580			$ -	$ -			$ -		$ -
RSVA - Retail Transmission Network Charge	1584			$ -	$ -			$ -		$ -
RSVA - Retail Transmission Connection Charge	1586			$ -	$ -			$ -		$ -
RSVA - Power (excluding Global Adjustment)	1588			$ -	$ -			$ -		$ -
RSVA - Power - Sub-Account - Global Adjustment	1588			$ -	$ -			$ -		$ -
Recovery of Regulatory Asset Balances	1590			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances (2008)[7]	1595			$ -	$ -			$ -		$ -
Disposition and Recovery of Regulatory Balances (2009)[7]	1595			$ -	$ -			$ -		$ -
Group 1 Sub-Total (including Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group 1 Sub-Total (excluding Account 1588 - Global Adjustment)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Special Purpose Charge Assessment Variance Account	**1521**							$ -		$ -
Deferred Payments in Lieu of Taxes	**1562**			$ -	$ -			$ -		$ -
Group 1 Total + 1521 + 1562		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592							$ -		$ -
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account	1592							$ -		$ -
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Ontario Energy Board

3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

In the green shaded cells, enter the most recent Board Approved volumetric forecast. If there is a material difference between the latest Board-approved volumetric forecast and the

Rate Class	Unit	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion*	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]
Residential	$/kWh				-				
Residential Urban	$/kWh				-				
General Service Less Than 50 kW	$/kWh				-				
General Service 50 to 999 kW	$/kWh				-				
General Service 1,000 to 4,999 kW	$/kWh				-				
Large Use > 5000 kW	$/kWh				-				
Unmetered Scattered Load	$/kWh				-				
Sentinel Lighting					-				
Street Lighting	$/kWh				-				
Standby - General Service 50 - 1,000 kW					-				
Standby - General Service 1,000 - 5,000 kW					-				
Standby - Large Use					-				
Total		-	-	-	-	-	0%	0%	0%

Total Claim (including Accounts 1521 and 1562)	$	-
Total Claim for Threshold Test (All Group 1 Accounts)	$	-
Threshold Test [3] (Total Claim per kWh)		

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balance.
[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.
[3] The Threshold Test does not include the amount in 1521 nor 1562.

No input required. This worksheet allocates the deferral/variance account balances (Group 1, 1521, 1588 GA and 1562) to the appropriate classes.

Allocation of Group 1 Accounts (Excluding Account 1588 - Global Adjustment)

Rate Class	Units	Billed kWh	% kWh	1550	1580	1584	1586	1588*	1590	1595 (2008)	1595 (2009)	1521	Total
Residential	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Residential Urban	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
General Service Less Than 50 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
General Service 50 to 999 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
General Service 1,000 to 4,999 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Large Use > 5000 kW	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Unmetered Scattered Load	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Sentinel Lighting	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Street Lighting	$/kWh	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - General Service 50 - 1,000 kW	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - General Service 1,000 - 5,000 kW	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Standby - Large Use	-	-	0.00%	0	0	0	0	0	0	0	0	0	0
Total		-	0.00%	0	0	0	0	0	0	0	0	0	0

** RSVA - Power (Excluding Global Adjustment)*

1588 RSVA - Power (Global Adjustment Sub-Account)

Rate Class	non-RPP kWh	% kWh	1588
Residential	-	0.00%	-
Residential Urban	-	0.00%	-
General Service Less Than 50 kW	-	0.00%	-
General Service 50 to 999 kW	-	0.00%	-
General Service 1,000 to 4,999 kW	-	0.00%	-
Large Use > 5000 kW	-	0.00%	-
Unmetered Scattered Load	-	0.00%	-
Sentinel Lighting	-	0.00%	-
Street Lighting	-	0.00%	-
Standby - General Service 50 - 1,000 kW	-	0.00%	-
Standby - General Service 1,000 - 5,000 kW	-	0.00%	-
Standby - Large Use	-	0.00%	-
Total	0	0.00%	0

Allocation of Account 1562

	% of Distribution Revenue	Allocation of Balance in Account 1562
Residential	0.0%	-
Residential Urban	0.0%	-
General Service Less Than 50 kW	0.0%	-
General Service 50 to 999 kW	0.0%	-
General Service 1,000 to 4,999 kW	0.0%	-
Large Use > 5000 kW	0.0%	-
Unmetered Scattered Load	0.0%	-
Sentinel Lighting	0.0%	-
Street Lighting	0.0%	-
Standby - General Service 50 - 1,000 kW	0.0%	-
Standby - General Service 1,000 - 5,000 kW	0.0%	-
Standby - Large Use	0.0%	-
Total	0.0%	-

Ontario Energy Board

Deferral / Variance Account Work Form

Toronto Hydro-Electric System Limited - EB-2011-0144

No input required. This worksheet calculates rate riders related to the Deferral/Variance Account Disposition (if applicable) and associated rate riders for the global adjustment sub-account.

Please indicate the Rate Rider Recovery Period (in years): 1

Rate Class	Unit	Billed kWh	Billed kW	Accounts Allocated by kWh/kW (RPP) or Distribution Revenue	Deferral/Variance Account Rate Rider	Account 1588 Global Adjustment	Billed kWh or Estimated kW for Non-RPP	Global Adjustment Rate Rider
Residential	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Residential Urban	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
General Service Less Than 50 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
General Service 50 to 999 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
General Service 1,000 to 4,999 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Large Use > 5000 kW	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Unmetered Scattered Load	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Sentinel Lighting	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Street Lighting	$/kWh	-	-	$ -	$0.00000	$ -	-	$0.00000
Standby - General Service 50 - 1,000 kW	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Standby - General Service 1,000 - 5,000 kW	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Standby - Large Use	-	-	-	$ -	$0.00000	$ -	-	$0.00000
Total		-	-	$ -		$ -		

Toronto Hydro-Electric System Limited - EB-2011-0144

Below is a listing of the current Monthly Fixed Charges. All rates with expired effective dates have been removed. In columns "B", "K", and "M" (green cells), please enter all additional Monthly Fixed Charges you are proposing (eg: Smart Meter Funding Adder, etc). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable).

Rate Description	Unit	Amount	Effective Until Date	Proposed Amount	Effective Until Date
Residential					
Service Charge (Based on 30 day month)	$	18.50	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	0.92	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	1.23	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.43	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			0.46	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.42	April 30 2015
	$				
Residential Urban					
Service Charge (Based on 30 day month)	$	17.23	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	0.34	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	0.46	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.16	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			0.17	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.16	April 30 2015
	$				
General Service Less Than 50 kW					
Service Charge (Based on 30 day month)	$	24.63	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	1.22	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	1.64	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.58	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			0.61	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.56	April 30 2015
	$				
General Service 50 to 999 kW					
Service Charge (Based on 30 day month)	$	36.05	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	1.79	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	2.40	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.84	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			0.90	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.82	April 30 2015
	$				
General Service 1,000 to 4,999 kW					
Service Charge (Based on 30 day month)	$	695.83	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	34.51	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	46.34	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	16.25	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			17.32	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			15.85	April 30 2015
	$				
Large Use > 5000 kW					
Service Charge (Based on 30 day month)	$	3050.17	April 30, 2015		
Smart Meter Funding Adder	$	0.68	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	151.26	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	203.11	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	71.22	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			75.94	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			69.46	April 30 2015
	$				
Unmetered Scattered Load					
Service Charge (Based on 30 day month)	$	4.91	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	0.02	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	0.03	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.01	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$			0.01	April 30 2015
Rate Rider for 2011 Unfunded Capex (per customer/30 days)	$			0.01	April 30 2015
	$				
Sentinel Lighting					
Service Charge (per connection)	$	0.50	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	0.24	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	0.33	April 30 2015		

2011 Unfunded Capex Rate Rider (per 30 days)	$	0.11	April 30 2014		
2014 ICM Rate Rider (per connection 30 days)	$			0.12	April 30 2015
Rate Rider for 2011 Unfunded Capex - (per connection/30 days)	$			0.11	April 30 2015
	$				
Street Lighting					
Service Charge (Based on 30 day month)	$	1.32	April 30, 2015		
2012 ICM Rate Rider (per 30 days)	$	0.07	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$	0.09	April 30 2015		
2011 Unfunded Capex Rate Rider (per 30 days)	$	0.03	April 30 2014		
2014 ICM Rate Rider (per connection 30 days)	$			0.03	April 30 2015
Rate Rider for 2011 Unfunded Capex - (per connection/30 days)	$			0.03	April 30 2015
	$				
Standby - General Service 50 - 1,000 kW					
Service Charge (Based on 30 day month)	$	200.61	April 30, 2015		
	$				
	$				
	$				
Standby - General Service 1,000 - 5,000 kW					
Service Charge (Based on 30 day month)	$	200.61	April 30, 2015		
	$				
	$				
	$				
Standby - Large Use					
Service Charge (Based on 30 day month)	$	200.61	April 30, 2015		
	$				
	$				
	$				

Toronto Hydro-Electric System Limited - EB-2011-0144

Below is a listing of the current Distribution Volumetric Rates other than the base rates. All rates with expired effective dates have been removed. In columns "B", "K", and "M" (green cells), please enter all additional volumetric rates you are proposing (eg: LRAM/SSM, Tax Adjustments, etc.). Please ensure that the word "Rider" or "Adder" is included in the description (as applicable).

Rate Description	Unit	Amount	Effective Until Date	Proposed Amount	Effective Until Date
Residential					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00077	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00103	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00036	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kWh			0.00039	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00035	April 30 2015
Residential Urban					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00131	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00176	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00062	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kWh			0.00066	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00060	April 30 2015
General Service Less Than 50 kW					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00115	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00154	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00054	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kWh			0.00058	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00053	April 30 2015
General Service 50 to 999 kW					
2012 ICM Rate Rider (per 30 days)	$/kVA	0.28130	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kVA	0.37770	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.13240	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kVA			0.14120	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kVA			0.12920	April 30 2015
General Service 1,000 to 4,999 kW					
2012 ICM Rate Rider (per 30 days)	$/kVA	0.22370	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kVA	0.30030	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.10530	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kVA			0.11230	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kVA			0.10270	April 30 2015
Large Use > 5000 kW					
2012 ICM Rate Rider (per 30 days)	$/kVA	0.23830	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kVA	0.32000	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.11220	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kVA			0.11960	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kVA			0.10940	April 30 2015

Unmetered Scattered Load					
2012 ICM Rate Rider (per 30 days)	$/kWh	0.00309	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kWh	0.00415	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kWh	0.00146	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kWh			0.00155	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kWh			0.00142	April 30 2015
Sentinel Lighting					
Street Lighting					
2012 ICM Rate Rider (per 30 days)	$/kVA	1.44390	April 30 2015		
2013 ICM Rate Rider (per 30 days)	$/kVA	1.93890	April 30 2015		
Rate Rider for 2011 Unfunded Capex (per 30 days)	$/kVA	0.67980	April 30 2014		
2014 ICM Rate Rider (per 30 days)	$/kVA			0.72490	April 30 2015
Rate Rider for 2011 Unfunded Capex	$/kVA			0.66300	April 30 2015
Standby - General Service 50 - 1,000 kW					
Standby - General Service 1,000 - 5,000 kW					
Standby - Large Use					

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3RD Generation Incentive Regulation Model

Toronto Hydro-Electric System Limited - EB-2011-0144

Current RTSR-Network Rates are listed below. In column "K", please enter your proposed RTSR-Network Rates as per Sheet 13 of the Board's RTSR Workform.

Rate Description	Unit	Current Amount	% Adjustment	Proposed Amount
Residential				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752	0.000%	0.00752
Residential Urban				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00752	0.000%	0.00752
General Service Less Than 50 kW				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00728	0.000%	0.00728
General Service 50 to 999 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.60566	0.000%	2.60566
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.51749	0.000%	2.51749
Large Use > 5000 kW				
Retail Transmission Rate – Network Service Rate	$/kW	2.86985	0.000%	2.86985
Unmetered Scattered Load				
Retail Transmission Rate – Network Service Rate	$/kWh	0.00458	0.000%	0.00458
Sentinel Lighting				
Street Lighting				
Retail Transmission Rate – Network Service Rate	$/kW	2.31750	0.000%	2.31750
Standby - General Service 50 - 1,000 kW				
Standby - General Service 1,000 - 5,000 kW				
Standby - Large Use				

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Current RTSR-Connection Rates are listed below. In column "K", please enter your proposed RTSR-Connection Rates as per Sheet 13 of the Board's RTSR Workform.

Rate Description	Unit	Current Amount	% Adjustment	Proposed Amount
Residential				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601	0.000%	0.00601
Residential Urban				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00601	0.000%	0.00601
General Service Less Than 50 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00542	0.000%	0.00542
General Service 50 to 999 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06482	0.000%	2.06482
General Service 1,000 to 4,999 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.06283	0.000%	2.06283
Large Use > 5000 kW				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.29168	0.000%	2.29168
Unmetered Scattered Load				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.00379	0.000%	0.00379
Sentinel Lighting				
Street Lighting				
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.46209	0.000%	2.46209
Standby - General Service 50 - 1,000 kW				
Standby - General Service 1,000 - 5,000 kW				
Standby - Large Use				

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If applicable, please enter any adjustments related to the revenue to cost ratio model into columns H and K.
The Price Escalator has been set at the 2011 values and will be updated by Board staff. The Stretch Factor Value will also be updated by Board staff.

Price Escalator 2.00% **Productivity Factor** 0.72% **Price Cap Index** 0.68%

Choose Stretch Factor Group III **Associated Stretch Factor Value** 0.6%

Rate Description	Unit	Current MFC	MFC Adjustment from R/C Model	Current Volumetric Charge	Unit	DVR Adjustment from R/C Model	Price Cap Index	Proposed MFC	Proposed Volumetric Charge
Residential	$	18.50		0.01528	$/kWh		0.680%	18.62	0.01538
Residential Urban	$	17.23		0.02600	$/kWh		0.680%	17.35	0.02618
General Service Less Than 50 kW	$	24.63		0.02278	$/kWh		0.680%	24.80	0.02293
General Service 50 to 999 kW	$	36.05		5.67196	$/kVA		0.680%	36.29	5.71053
General Service 1,000 to 4,999 kW	$	695.83		4.51042	$/kVA		0.680%	700.56	4.54109
Large Use > 5000 kW	$	3,050.17		4.80529	$/kVA		0.680%	3,070.91	4.83797
Unmetered Scattered Load	$	4.91		0.06153	$/kWh		0.680%	4.94	0.06195
Sentinel Lighting	$	0.50					0.680%	0.50	
Street Lighting	$	1.32		29.11679	$/kVA		0.680%	1.33	29.31478
Standby - General Service 50 - 1,000 kW	$	200.61		5.67196	$/kVA		0.680%	201.97	5.71053
Standby - General Service 1,000 - 5,000 kW	$	200.61		4.51042	$/kVA		0.680%	201.97	4.54109
Standby - Large Use	$	200.61		4.80529	$/kVA		0.680%	201.97	4.83797

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Please enter the descriptions of the current Loss Factors from your most recent Board-Approved Tariff of Rates and Charges by using the drop-down menu in the column labeled "Loss Factors". If the description is not found in the drop-down menu, please enter the description in the green cells under the correct classes.

Loss Factors	Current
Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0376
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.1087
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0272
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0085

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Toronto Hydro-Electric System Limited - EB-2011-0144

The standard Allowance rates have been included as default entries. If you have different rates, please make the appropriate corrections in the below. As well, please enter the current Specific Service Charges below. The standard Retail Service Charges have been entered below. If you rates, please make the appropriate corrections in columns B, D or E as applicable (cells are unlocked).

ALLOWANCES

	UNIT	CURRENT
Transformer Allowance for Ownership - per kVA of billing demand/30 days	$/kVA	(0.62)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

	UNIT	CURRENT
Duplicate invoices for previous billing	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Request for other billing information	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month		%	1.50
Late Payment - per annum		%	19.56
Collection of account charge - no disconnection		$	30.00
Disconnect/Reconnect at meter - during regular hours		$	65.00
Disconnect/Reconnect at meter - after regular hours		$	185.00
Disconnect/Reconnect at pole - during regular hours		$	185.00
Disconnect/Reconnect at pole - after regular hours	**/C**	$	415.00

Other

Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Specific Charge for Access to the Power Poles $/pole/year	$	18.55
Specific Charge for Access to the Power Poles $/pole/year	$	-22.75

Residential	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	18.50	18.50	1	18.62	18.62	0.12	0.6%
Distribution	800	0.01528	12.22	800	0.01538	12.30	0.08	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.43	0.43	1	0.42	0.42	(0.01)	-2.3%
2011 Unfunded Capex Rate Rider - DVR	800	0.00036	0.29	800	0.00035	0.28	(0.01)	-2.8%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	0.92	0.92	1	0.92	0.92	-	0.0%
2012 ICM Rate Rider - DVR	800	0.00077	0.62	800	0.00077	0.62	-	0.0%
2013 ICM Rate Rider - MFC	1	1.23	1.23	1	1.23	1.23	-	0.0%
2013 ICM Rate Rider - DVR	800	0.00103	0.82	800	0.00103	0.82	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	1	0.46	0.46	0.46	n/a
2014 ICM Rate Rider - DVR	-	-	-	800	0.00039	0.31	0.31	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			35.71			36.67	0.95	2.7%
RTST - Network	830.08	0.00752	6.24	830.08	0.00752	6.24	-	0.0%
RTSR - Connection	830.08	0.00601	4.99	830.08	0.00601	4.99	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			46.94			47.90	0.95	2.0%
Wholesale Market Rate	830	0.00520	4.32	830	0.00520	4.32	-	0.0%
RRRP (May 1, 2012)	830	0.00110	0.91	830	0.00110	0.91	-	0.0%
DRC	800	0.00700	5.60	800	0.00700	5.60	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	830	-	-	830	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	600	0.075	45.00	600	0.075	45.00	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	230	0.088	20.25	230	0.088	20.25	-	0.0%
Total Bill (including Sub-Total B)			123.27			124.22	0.95	0.8%

	kWh
Consumption Details	**800**
Total Loss Factor	1.0376

Competitive Sector Multi-Unit Residential	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	17.23	17.23	1	17.35	17.35	0.12	0.7%
Distribution	334	0.02600	8.68	334	0.02618	8.74	0.06	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.16	0.16	1	0.16	0.16	-	0.0%
2011 Unfunded Capex Rate Rider - DVR	334	0.00062	0.21	334	0.00060	0.20	(0.01)	-3.2%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	0.34	0.34	1	0.34	0.34	-	0.0%
2012 ICM Rate Rider - DVR	334	0.00131	0.44	334	0.00131	0.44	-	0.0%
2013 ICM Rate Rider - MFC	1	0.46	0.46	1	0.46	0.46	-	0.0%
2013 ICM Rate Rider - DVR	334	0.00176	0.59	334	0.00176	0.59	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	1	0.17	0.17	0.17	n/a
2014 ICM Rate Rider - DVR	-	-	-	334	0.00066	0.22	0.22	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			28.79			29.35	0.56	2.0%
RTST - Network	346.56	0.00752	2.61	346.56	0.00752	2.61	-	0.0%
RTSR - Connection	346.56	0.00601	2.08	346.56	0.00601	2.08	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			33.48			34.04	0.56	1.7%
Wholesale Market Rate	347	0.00520	1.80	347	0.00520	1.80	-	0.0%
RRRP (May 1, 2012)	347	0.00110	0.38	347	0.00110	0.38	-	0.0%
DRC	334	0.00700	2.34	334	0.00700	2.34	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
SPC	347	-	-	347	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	347	0.075	25.99	347	0.075	25.99	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	-	0.088	-	-	0.088	-	-	n/a
Total Bill (including Sub-Total B)			64.24			64.80	0.56	0.9%

	kWh
Consumption Details	**334**
Total Loss Factor	1.0376

GS < 50 kW	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	24.63	24.63	1	24.80	24.80	0.17	0.7%
Distribution	2,000	0.02278	45.56	2,000	0.02293	45.86	0.30	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.58	0.58	1	0.56	0.56	(0.02)	-3.4%
2011 Unfunded Capex Rate Rider - DVR	2,000	0.00054	1.08	2,000	0.00053	1.06	(0.02)	-1.9%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	1.22	1.22	1	1.22	1.22	-	0.0%
2012 ICM Rate Rider - DVR	2,000	0.00115	2.30	2,000	0.00115	2.30	-	0.0%
2013 ICM Rate Rider - MFC	1	1.64	1.64	1	1.64	1.64	-	0.0%
2013 ICM Rate Rider - DVR	2,000	0.00154	3.08	2,000	0.00154	3.08	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	1	0.61	0.61	0.61	n/a
2014 ICM Rate Rider - DVR	-	-	-	2,000	0.00058	1.16	1.16	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			80.77			82.97	2.20	2.7%
RTST - Network	2,075	0.00728	15.11	2,075	0.00728	15.11	-	0.0%
RTSR - Connection	2,075	0.00542	11.25	2,075	0.00542	11.25	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			107.13			109.33	2.20	2.1%
Wholesale Market Rate	2,075	0.0052	10.79	2,075	0.0052	10.79	-	0.0%
RRRP (May 1, 2012)	2,075	0.00110	2.28	2,075	0.00110	2.28	-	0.0%
DRC	2,000	0.0070	14.00	2,000	0.0070	14.00	-	0.0%
Standard Supply Service Charge	1.00	0.25	0.25	1.00	0.25	0.25	-	0.0%
Special Purpose Charge	2,075	-	-	2,075	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	1,325	0.088	116.62	1,325	0.088	116.62	-	0.0%
Total Bill (including Sub-Total B)			307.32			309.52	2.20	0.7%

	kWh
Consumption Details	**2,000.00**
Total Loss Factor	1.0376

GS > 50 < 1000 kW	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	36.05	36.05	1	36.29	36.29	0.24	0.7%
Distribution	388	5.6720	2,200.74	388	5.7105	2,215.67	14.94	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - Global Adjustment - Non RPP	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.84	0.84	1	0.82	0.82	(0.02)	-2.4%
2011 Unfunded Capex Rate Rider - DVR	388	0.1324	51.37	388	0.1292	50.13	(1.24)	-2.4%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	1.79	1.79	1	1.79	1.79	-	0.0%
2012 ICM Rate Rider - DVR	388	0.2813	109.14	388	0.2813	109.14	-	0.0%
2013 ICM Rate Rider - MFC	1	2.40	2.40	1	2.40	2.40	-	0.0%
2013 ICM Rate Rider - DVR	388	0.3777	146.55	388	0.3777	146.55	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	1	0.90	0.90	0.90	n/a
2014 ICM Rate Rider - DVR	-	-	-	388	0.1412	54.79	54.79	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			2,549.56			2,619.16	69.60	2.7%
RTST - Network	349	2.6057	909.39	349	2.6057	909.39	-	0.0%
RTSR - Connection	349	2.0648	720.62	349	2.0648	720.62	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			4,179.56			4,249.17	69.60	1.7%
Wholesale Market Rate	155,640	0.0052	809.33	155,640	0.0052	809.33	-	0.0%
RRRP (May 1, 2012)	155,640	0.00110	171.20	155,640	0.00110	171.20	-	0.0%
DRC	150,000	0.0070	1,050.00	150,000	0.0070	1,050.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	155,640	-	-	155,640	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	154,890	0.088	13,630.32	154,890	0.088	13,630.32	-	0.0%
Total Bill (including Sub-Total B)			19,896.92			19,966.52	69.60	0.3%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	150,000	349	388	430	90%	100%
Total Loss Factor	1.0376					

GS > 1000 < 5000 kW	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	695.83	695.83	1	700.56	700.56	4.73	0.7%
Distribution	1,778	4.5104	8,019.49	1,778	4.5411	8,074.08	54.58	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - Global Adjustment - Non RPP	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	16.25	16.25	1	15.85	15.85	(0.40)	-2.5%
2011 Unfunded Capex Rate Rider - DVR	1,778	0.10530	187.22	1,778	0.10270	182.60	(4.62)	-2.5%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	34.51	34.51	1	34.51	34.51	-	0.0%
2012 ICM Rate Rider - DVR	1,778	0.22370	397.74	1,778	0.22370	397.74	-	0.0%
2013 ICM Rate Rider - MFC	1	46.34	46.34	1	46.34	46.34	-	0.0%
2013 ICM Rate Rider - DVR	1,778	0.30030	533.93	1,778	0.30030	533.93	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	1	17.32	17.32	17.32	n/a
2014 ICM Rate Rider - DVR	-	-	-	1,778	0.11230	199.67	199.67	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			9,932.00			10,203.28	271.28	2.7%
RTST - Network	1,600	2.5175	4,028.00	1,600	2.5175	4,028.00	-	0.0%
RTSR - Connection	1,600	2.0628	3,300.48	1,600	2.0628	3,300.48	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			17,260.48			17,531.76	271.28	1.6%
Wholesale Market Rate	830,080	0.0052	4,316.42	830,080	0.0052	4,316.42	-	0.0%
RRRP (May 1, 2012)	830,080	0.00110	913.09	830,080	0.00110	913.09	-	0.0%
DRC	800,000	0.0070	5,600.00	800,000	0.0070	5,600.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	830,080	-	-	830,080	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	829,330	0.088	72,981.04	829,330	0.088	72,981.04	-	0.0%
Total Bill (including Sub-Total B)			101,127.52			101,398.80	271.28	0.3%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	800,000	1,600	1,778	500	90%	100%

Total Loss Factor	1.0376

LU	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	3,050.17	3,050.17	1	3,070.91	3,070.91	20.74	0.7%
Distribution	9,434	4.8053	45,333.20	9,434	4.8380	45,641.69	308.49	0.7%
Smart Meter Rider (per 30 days)	1	0.68	0.68	1	0.68	0.68	-	0.0%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - Global Adjustment - Non RPP	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	71.22	71.22	1	69.46	69.46	(1.76)	-2.5%
2011 Unfunded Capex Rate Rider - DVR	9,434	0.1122	1,058.49	9,434	0.1094	1,032.08	(26.42)	-2.5%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	151.26	151.26	1	151.26	151.26	-	0.0%
2012 ICM Rate Rider - DVR	9,434	0.2383	2,248.12	9,434	0.2383	2,248.12	-	0.0%
2013 ICM Rate Rider - MFC	1	203.11	203.11	1	203.11	203.11	-	0.0%
2013 ICM Rate Rider - DVR	9,434	0.3200	3,018.88	9,434	0.3200	3,018.88	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	1	75.94	75.94	75.94	n/a
2014 ICM Rate Rider - DVR	-	-	-	9,434	0.1196	1,128.31	1,128.31	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			55,135.14			56,640.44	1,505.30	2.7%
RTST - Network	8,491	2.8699	24,368.32	8,491	2.8699	24,368.32	-	0.0%
RTSR - Connection	8,491	2.2917	19,458.82	8,491	2.2917	19,458.82	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			98,962.28			100,467.59	1,505.30	1.5%
Wholesale Market Rate	4,584,150	0.0052	23,837.58	4,584,150	0.0052	23,837.58	-	0.0%
RRRP (May 1, 2012)	4,584,150	0.00110	5,042.57	4,584,150	0.00110	5,042.57	-	0.0%
DRC	4,500,000	0.0070	31,500.00	4,500,000	0.0070	31,500.00	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	4,584,150	-	-	4,584,150	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	4,583,400	0.088	403,339.20	4,583,400	0.088	403,339.20	-	0.0%
Total Bill (including Sub-Total B)			562,738.13			564,243.43	1,505.30	0.3%

	kWh	kW	kVA	Hours Use	PF	Net/Conn
Consumption Details	4,500,000	8,491	9,434	530	90%	100%

Total Loss Factor	1.0187

Street Lights	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Connection Charge	162,353	1.32	214,306.51	162,353	1.33	215,930.04	1,623.53	0.8%
Distribution	25,755	29.1168	749,903.18	25,755	29.3148	755,002.67	5,099.49	0.7%
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	162,353.42	0.03	4,870.60	162,353.42	0.03	4,870.60	-	0.0%
2011 Unfunded Capex Rate Rider - DVR	25,755.00	0.6798	17,508.25	25,755.00	0.6630	17,075.57	(432.68)	-2.5%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	162,353.42	0.07	11,364.74	162,353.42	0.07	11,364.74	-	0.0%
2012 ICM Rate Rider - DVR	25,755.00	1.4439	37,187.64	25,755.00	1.4439	37,187.64	-	0.0%
2013 ICM Rate Rider - MFC	162,353.42	0.09	14,611.81	162,353.42	0.09	14,611.81	-	0.0%
2013 ICM Rate Rider - DVR	25,755.00	1.9389	49,936.37	25,755.00	1.9389	49,936.37	-	0.0%
2014 ICM Rate Rider - MFC	-	-	-	162,353.42	0.03	4,870.60	4,870.60	n/a
2014 ICM Rate Rider - DVR	-	-	-	25,755.00	0.7249	18,669.80	18,669.80	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			1,099,689.11			1,129,519.85	29,830.74	2.7%
RTST - Network	25,755	2.3175	59,687.21	25,755	2.3175	59,687.21	-	0.0%
RTSR - Connection	25,755	2.4621	63,411.39	25,755	2.4621	63,411.39	-	0.0%
Sub Total B (including Sub-Total A) - Distribution		-	1,222,787.70		-	1,252,618.45	29,830.74	2.4%
Wholesale Market Rate	9,620,365	0.0052	50,025.90	9,620,365	0.0052	50,025.90	-	0.0%
RRRP (May 1, 2012)	9,620,365	0.00110	10,582.40	9,620,365	0.00110	10,582.40	-	0.0%
DRC	9,271,748	0.0070	64,902.23	9,271,748	0.0070	64,902.23	-	0.0%
Standard Supply Service Charge	1	0.25	0.25	1	0.25	0.25	-	0.0%
Special Purpose Charge	9,620,365	-	-	9,620,365	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	750	0.075	56.25	750	0.075	56.25	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	9,619,615	0.088	846,526.14	9,619,615	0.088	846,526.14	-	0.0%
Total Bill (including Sub-Total B)			2,194,880.87			2,224,711.62	29,830.74	1.4%

	kWh	Connections	kW	KVA	**Hours Use**	**PF**	**Net/Conn**
Consumption Details	9,271,747.50	162,353	25,755	25,755.00	360	100%	100%
Total Loss Factor	1.0376						

USL	2013			2014			Impact	
	Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %
Service Charge (per 30 days)	1	4.91	4.91	1	4.94	4.94	0.03	0.6%
Connection Charge	1	0.50	0.50	1	0.50	0.50	-	0.0%
Distribution	365	0.06153	22.46	365	0.06195	22.61	0.15	0.7%
LRAM Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011/12 Rate Rider	-	-	-	-	-	-	-	n/a
Regulatory Assets - 2011 Rate Rider	-	-	-	-	-	-	-	n/a
Contact Voltage	-	-	-	-	-	-	-	n/a
Late Payment Penalty	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - fixed rate - customer	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate - connection	-	-	-	-	-	-	-	n/a
Foregone Revenue Rate Rider - variable rate	-	-	-	-	-	-	-	n/a
2011 Unfunded Capex Rate Rider - MFC	1	0.01	0.01	1	0.01	0.01	-	0.0%
2011 Unfunded Capex Rate Rider - MFC (Connection)	1	0.11	0.11	1	0.11	0.11	-	0.0%
2011 Unfunded Capex Rate Rider - DVR	365	0.00146	0.53	365	0.00142	0.52	(0.01)	-2.7%
Shared Tax Savings Rate Rider - DVR	-	-	-	-	-	-	-	n/a
2012 ICM Rate Rider - MFC	1	0.02	0.02	1	0.02	0.02	-	0.0%
2012 ICM Rate Rider - MFC (Connection)	1	0.24	0.24	1	0.24	0.24	-	0.0%
2012 ICM Rate Rider - DVR	365	0.00309	1.13	365	0.00309	1.13	-	0.0%
2013 ICM Rate Rider - MFC	1	0.03	0.03	1	0.03	0.03	-	0.0%
2013 ICM Rate Rider - MFC (Connection)	1	0.33	0.33	1	0.33	0.33	-	0.0%
2013 ICM Rate Rider - DVR	365	0.00415	1.51	365	0.00415	1.51	-	0.0%
2014 ICM Rate Rider - MFC			-	1	0.010	0.01	0.01	n/a
2014 ICM Rate Rider - MFC (Connection)			-	1	0.12	0.12	0.12	n/a
2014 ICM Rate Rider - DVR			-	365	0.00155	0.57	0.57	n/a
Deferral/Variance Account Rate Rider	-	-	-	-	-	-	-	n/a
Sub Total A - Distribution			31.78			32.65	0.86	2.7%
RTST - Network	379	0.00458	1.73	379	0.00458	1.73	-	0.0%
RTSR - Connection	379	0.00379	1.44	379	0.00379	1.44	-	0.0%
Sub Total B (including Sub-Total A) - Distribution			34.95			35.82	0.86	2.5%
Wholesale Market Rate	379	0.00520	1.97	379	0.00520	1.97	-	0.0%
RRRP (May 1, 2012)	379	0.00110	0.42	379	0.00110	0.42	-	0.0%
DRC	365	0.00700	2.56	365	0.00700	2.56	-	0.0%
Standard Supply Service Charge	1	0.25000	0.25	1	0.25000	0.25	-	0.0%
Special Purpose Charge	-	-	-	-	-	-	-	n/a
Cost of Power Commodity - 1st Tier (May 1, 2012)	379	0.075	28.40	379	0.075	28.40	-	0.0%
Cost of Power Commodity - 2nd Tier (May 1, 2012)	-	0.088	-	-	0.088	-	-	n/a
Total Bill (including Sub-Total B)			68.55			69.41	0.86	1.3%

	Kwh	Customer	Connection
Consumption Details	365	1	1
Total Loss Factor	1.0376		

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Choose Your Utility:

Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited

Application Type:	IRM3
OEB Application #:	EB-2011-0144
LDC Licence #:	ED-2002-0497
Last COS OEB Application #:	EB-201
Last COS Re-Basing Year:	2011

Application Contact Information

Name:	Anthony Lam
Title:	Economist
Phone Number:	416 542-2876
Email Address:	alam@torontohydro.com

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RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

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RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR - Network		RTSR - Connection	
Residential	kWh	$	0.0070	$	0.0051
Residential Urban	kWh	$	0.0070	$	0.0051
General Service Less Than 50 kW	kWh	$	0.0068	$	0.0046
General Service 50 to 999 kW	kW	$	2.4351	$	1.7630
General Service 1,000 to 4,999 kW	kW	$	2.3527	$	1.7613
Large Use	kW	$	2.6820	$	1.9567
Street Lighting	kW	$	2.1658	$	2.1022
Unmetered Scattered Load	kWh	$	0.0043	$	0.0032
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
Choose Rate Class					
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Choose Rate Class					
Choose Rate Class					

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

In the green shaded cells, enter the most recent reported RRR billing determinants. Please ensure that billing determinants are non-loss adjusted.

Rate Class	Unit	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor	Load Factor	Loss Adjusted Billed kWh	Billed kW
Residential	**kWh**	5,105,974,275	-	1.0376		5,297,958,908	-
Residential Urban	**kWh**	99,791,184	-	1.0376		103,543,333	-
General Service Less Than 50 kW	**kWh**	2,095,343,918	-	1.0376		2,174,128,849	-
General Service 50 to 999 kW	**kW**	10,189,051,346	26,712,248		**52.28%**	10,189,051,346	26,712,248
General Service 1,000 to 4,999 kW	**kW**	4,828,382,733	10,972,419		**60.31%**	4,828,382,733	10,972,419
Large Use	**kW**	2,263,227,585	5,267,224		**58.89%**	2,263,227,585	5,267,224
Street Lighting	**kW**	112,727,603	321,995		**47.98%**	112,727,603	321,995
Unmetered Scattered Load	**kWh**	52,097,299	-	1.0376		54,056,157	-

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

Uniform Transmission Rates

Rate Description	Unit	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate
Network Service Rate	kW	$ 2.97	$ 3.22	$ 3.57
Line Connection Service Rate	kW	$ 0.73	$ 0.79	$ 0.80
Transformation Connection Service Rate	kW	$ 1.71	$ 1.77	$ 1.86

Hydro One Sub-Transmission Rates

Rate Description	Unit	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate
Network Service Rate	kW	$ 2.65	$ 2.65	$ 2.65
Line Connection Service Rate	kW	$ 0.64	$ 0.64	$ 0.64
Transformation Connection Service Rate	kW	$ 1.50	$ 1.50	$ 1.50
Both Line and Transformation Connection Service Rate	kW	$ 2.14	$ 2.14	$ 2.14

Hydro One Sub-Transmission Rate Rider 6A

Rate Description	Unit	Effective January 1, 2010 Rate	Effective January 1, 2011 Rate	Effective January 1, 2012 Rate
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.0470	$ 0.0470	$ 0.0470
RSVA Transmission connection – 4716 – which affects 1586	kW	-$ 0.0250	-$ 0.0250	-$ 0.0250
RSVA LV – 4750 – which affects 1550	kW	$ 0.0580	$ 0.0580	$ 0.0580
RARA 1 – 2252 – which affects 1590	kW	-$ 0.0750	-$ 0.0750	-$ 0.0750
Hydro One Sub-Transmission Rate Rider 6A	kW	$ 0.0050	$ 0.0050	$ 0.0050

		Historical 2010	Current 2011	Forecast 2012
Low Voltage Switchgear Credit	$	- 8,169,997	- 8,411,016	8,732,452

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$2.97	$ 11,803,240	3,920,041	$0.73	$ 2,861,630	4,005,793	$1.71	$ 6,849,906	$ 9,711,536
February	3,872,348	$2.97	$ 11,500,874	3,818,005	$0.73	$ 2,787,144	3,906,487	$1.71	$ 6,680,093	$ 9,467,236
March	3,533,613	$2.97	$ 10,494,831	3,487,061	$0.73	$ 2,545,555	3,556,102	$1.71	$ 6,080,934	$ 8,626,489
April	3,225,020	$2.97	$ 9,578,309	3,270,132	$0.73	$ 2,387,196	3,330,873	$1.71	$ 5,695,793	$ 8,082,989
May	4,203,820	$2.97	$ 12,485,345	4,149,759	$0.73	$ 3,029,324	4,255,406	$1.71	$ 7,276,744	$ 10,306,068
June	4,025,876	$2.97	$ 11,956,852	3,946,823	$0.73	$ 2,881,181	4,046,593	$1.71	$ 6,919,674	$ 9,800,855
July	4,795,334	$2.97	$ 14,242,142	4,667,508	$0.73	$ 3,407,281	4,763,100	$1.71	$ 8,144,901	$ 11,552,182
August	4,541,370	$2.97	$ 13,487,869	4,457,988	$0.73	$ 3,254,331	4,552,896	$1.71	$ 7,785,452	$ 11,039,783
September	4,582,171	$2.97	$ 13,609,048	4,426,635	$0.73	$ 3,231,444	4,518,575	$1.71	$ 7,726,763	$ 10,958,207
October	3,254,324	$2.97	$ 9,665,342	3,300,173	$0.73	$ 2,409,126	3,382,379	$1.71	$ 5,783,868	$ 8,192,994
November	3,537,782	$2.97	$ 10,507,213	3,466,344	$0.73	$ 2,530,431	3,538,025	$1.71	$ 6,050,023	$ 8,580,454
December	4,013,769	$2.97	$ 11,920,894	3,877,690	$0.73	$ 2,830,714	3,960,416	$1.71	$ 6,772,311	$ 9,603,025
Total	47,559,582	$ 2.97	$ 141,251,959	46,788,159	$ 0.73	$ 34,155,356	47,816,645	$ 1.71	$ 81,766,463	$ 115,921,819

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$2.97	$ 11,803,240	3,920,041	$0.73	$ 2,861,630	4,005,793	$1.71	$ 6,849,906	$ 9,711,536
February	3,872,348	$2.97	$ 11,500,874	3,818,005	$0.73	$ 2,787,144	3,906,487	$1.71	$ 6,680,093	$ 9,467,236
March	3,533,613	$2.97	$ 10,494,831	3,487,061	$0.73	$ 2,545,555	3,556,102	$1.71	$ 6,080,934	$ 8,626,489
April	3,225,020	$2.97	$ 9,578,309	3,270,132	$0.73	$ 2,387,196	3,330,873	$1.71	$ 5,695,793	$ 8,082,989
May	4,203,820	$2.97	$ 12,485,345	4,149,759	$0.73	$ 3,029,324	4,255,406	$1.71	$ 7,276,744	$ 10,306,068
June	4,025,876	$2.97	$ 11,956,852	3,946,823	$0.73	$ 2,881,181	4,046,593	$1.71	$ 6,919,674	$ 9,800,855
July	4,795,334	$2.97	$ 14,242,142	4,667,508	$0.73	$ 3,407,281	4,763,100	$1.71	$ 8,144,901	$ 11,552,182
August	4,541,370	$2.97	$ 13,487,869	4,457,988	$0.73	$ 3,254,331	4,552,896	$1.71	$ 7,785,452	$ 11,039,783
September	4,582,171	$2.97	$ 13,609,048	4,426,635	$0.73	$ 3,231,444	4,518,575	$1.71	$ 7,726,763	$ 10,958,207
October	3,254,324	$2.97	$ 9,665,342	3,300,173	$0.73	$ 2,409,126	3,382,379	$1.71	$ 5,783,868	$ 8,192,994
November	3,537,782	$2.97	$ 10,507,213	3,466,344	$0.73	$ 2,530,431	3,538,025	$1.71	$ 6,050,023	$ 8,580,454
December	4,013,769	$2.97	$ 11,920,894	3,877,690	$0.73	$ 2,830,714	3,960,416	$1.71	$ 6,772,311	$ 9,603,025
Total	47,559,582	$ 2.97	$ 141,251,959	46,788,159	$ 0.73	$ 34,155,356	47,816,645	$ 1.71	$ 81,766,463	$ 115,921,819

Low Voltage Switchgear Credit	- 8,169,997
	$ 107,751,822

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to calculate the expected billing when current 2011 Uniform Transmission Rates are applied against historical 2010 transmission units.

IESO

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$ 3.2200	$ 12,796,779	3,920,041	$ 0.7900	$ 3,096,832	4,005,793	$ 1.7700	$ 7,090,254	$ 10,187,086
February	3,872,348	$ 3.2200	$ 12,468,961	3,818,005	$ 0.7900	$ 3,016,224	3,906,487	$ 1.7700	$ 6,914,482	$ 9,930,706
March	3,533,613	$ 3.2200	$ 11,378,234	3,487,061	$ 0.7900	$ 2,754,778	3,556,102	$ 1.7700	$ 6,294,301	$ 9,049,079
April	3,225,020	$ 3.2200	$ 10,384,564	3,270,132	$ 0.7900	$ 2,583,404	3,330,873	$ 1.7700	$ 5,895,645	$ 8,479,049
May	4,203,820	$ 3.2200	$ 13,536,300	4,149,759	$ 0.7900	$ 3,278,310	4,255,406	$ 1.7700	$ 7,532,069	$ 10,810,378
June	4,025,876	$ 3.2200	$ 12,963,321	3,946,823	$ 0.7900	$ 3,117,990	4,046,593	$ 1.7700	$ 7,162,470	$ 10,280,460
July	4,795,334	$ 3.2200	$ 15,440,975	4,667,508	$ 0.7900	$ 3,687,331	4,763,100	$ 1.7700	$ 8,430,687	$ 12,118,018
August	4,541,370	$ 3.2200	$ 14,623,211	4,457,988	$ 0.7900	$ 3,521,811	4,552,896	$ 1.7700	$ 8,058,626	$ 11,580,436
September	4,582,171	$ 3.2200	$ 14,754,591	4,426,635	$ 0.7900	$ 3,497,042	4,518,575	$ 1.7700	$ 7,997,878	$ 11,494,919
October	3,254,324	$ 3.2200	$ 10,478,923	3,300,173	$ 0.7900	$ 2,607,137	3,382,379	$ 1.7700	$ 5,986,811	$ 8,593,948
November	3,537,782	$ 3.2200	$ 11,391,658	3,466,344	$ 0.7900	$ 2,738,412	3,538,025	$ 1.7700	$ 6,262,304	$ 9,000,716
December	4,013,769	$ 3.2200	$ 12,924,336	3,877,690	$ 0.7900	$ 3,063,375	3,960,416	$ 1.7700	$ 7,009,936	$ 10,073,311
Total	47,559,582	$ 3.22	$ 153,141,854	46,788,159	$ 0.79	$ 36,962,646	47,816,645	$ 1.77	$ 84,635,462	$ 121,598,107

HYDRO ONE

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

TOTAL

Month	Network Units Billed	Network Rate	Network Amount	Line Connection Units Billed	Line Connection Rate	Line Connection Amount	Transformation Connection Units Billed	Transformation Connection Rate	Transformation Connection Amount	Total Line Amount
January	3,974,155	$ 3.22	$ 12,796,779	3,920,041	$ 0.79	$ 3,096,832	4,005,793	$ 1.77	$ 7,090,254	$ 10,187,086
February	3,872,348	$ 3.22	$ 12,468,961	3,818,005	$ 0.79	$ 3,016,224	3,906,487	$ 1.77	$ 6,914,482	$ 9,930,706
March	3,533,613	$ 3.22	$ 11,378,234	3,487,061	$ 0.79	$ 2,754,778	3,556,102	$ 1.77	$ 6,294,301	$ 9,049,079
April	3,225,020	$ 3.22	$ 10,384,564	3,270,132	$ 0.79	$ 2,583,404	3,330,873	$ 1.77	$ 5,895,645	$ 8,479,049
May	4,203,820	$ 3.22	$ 13,536,300	4,149,759	$ 0.79	$ 3,278,310	4,255,406	$ 1.77	$ 7,532,069	$ 10,810,378
June	4,025,876	$ 3.22	$ 12,963,321	3,946,823	$ 0.79	$ 3,117,990	4,046,593	$ 1.77	$ 7,162,470	$ 10,280,460
July	4,795,334	$ 3.22	$ 15,440,975	4,667,508	$ 0.79	$ 3,687,331	4,763,100	$ 1.77	$ 8,430,687	$ 12,118,018
August	4,541,370	$ 3.22	$ 14,623,211	4,457,988	$ 0.79	$ 3,521,811	4,552,896	$ 1.77	$ 8,058,626	$ 11,580,436
September	4,582,171	$ 3.22	$ 14,754,591	4,426,635	$ 0.79	$ 3,497,042	4,518,575	$ 1.77	$ 7,997,878	$ 11,494,919
October	3,254,324	$ 3.22	$ 10,478,923	3,300,173	$ 0.79	$ 2,607,137	3,382,379	$ 1.77	$ 5,986,811	$ 8,593,948
November	3,537,782	$ 3.22	$ 11,391,658	3,466,344	$ 0.79	$ 2,738,412	3,538,025	$ 1.77	$ 6,262,304	$ 9,000,716
December	4,013,769	$ 3.22	$ 12,924,336	3,877,690	$ 0.79	$ 3,063,375	3,960,416	$ 1.77	$ 7,009,936	$ 10,073,311
Total	47,559,582	$ 3.22	$ 153,141,854	46,788,159	$ 0.79	$ 36,962,646	47,816,645	$ 1.77	$ 84,635,462	$ 121,598,107

Low Voltage Switchgear Credit	- 8,411,016
	$ 113,187,091

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to calculate the expected billing when forecasted 2012 Uniform Transmission Rates are applied against historical 2010 transmission units.

IESO

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	3,974,155	$ 3.5700	$ 14,187,733	3,920,041	$ 0.8000	$ 3,136,033	4,005,793	$ 1.8600	$ 7,450,775	$ 10,586,808
February	3,872,348	$ 3.5700	$ 13,824,282	3,818,005	$ 0.8000	$ 3,054,404	3,906,487	$ 1.8600	$ 7,266,066	$ 10,320,470
March	3,533,613	$ 3.5700	$ 12,614,998	3,487,061	$ 0.8000	$ 2,789,649	3,556,102	$ 1.8600	$ 6,614,350	$ 9,403,999
April	3,225,020	$ 3.5700	$ 11,513,321	3,270,132	$ 0.8000	$ 2,616,106	3,330,873	$ 1.8600	$ 6,195,424	$ 8,811,529
May	4,203,820	$ 3.5700	$ 15,007,637	4,149,759	$ 0.8000	$ 3,319,807	4,255,406	$ 1.8600	$ 7,915,055	$ 11,234,862
June	4,025,876	$ 3.5700	$ 14,372,377	3,946,823	$ 0.8000	$ 3,157,458	4,046,593	$ 1.8600	$ 7,526,663	$ 10,684,121
July	4,795,334	$ 3.5700	$ 17,119,342	4,667,508	$ 0.8000	$ 3,734,006	4,763,100	$ 1.8600	$ 8,859,366	$ 12,593,372
August	4,541,370	$ 3.5700	$ 16,212,691	4,457,988	$ 0.8000	$ 3,566,390	4,552,896	$ 1.8600	$ 8,468,387	$ 12,034,777
September	4,582,171	$ 3.5700	$ 16,358,350	4,426,635	$ 0.8000	$ 3,541,308	4,518,575	$ 1.8600	$ 8,404,550	$ 11,945,858
October	3,254,324	$ 3.5700	$ 11,617,937	3,300,173	$ 0.8000	$ 2,640,138	3,382,379	$ 1.8600	$ 6,291,225	$ 8,931,363
November	3,537,782	$ 3.5700	$ 12,629,882	3,466,344	$ 0.8000	$ 2,773,075	3,538,025	$ 1.8600	$ 6,580,727	$ 9,353,802
December	4,013,769	$ 3.5700	$ 14,329,155	3,877,690	$ 0.8000	$ 3,102,152	3,960,416	$ 1.8600	$ 7,366,374	$ 10,468,526
Total	47,559,582	$ 3.57	$ 169,787,708	46,788,159	$ 0.80	$ 37,430,527	47,816,645	$ 1.86	$ 88,938,960	$ 126,369,487

HYDRO ONE

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
February	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
March	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
April	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
May	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
June	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
July	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
August	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
September	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
October	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
November	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
December	-	$ 2.6970	$ -	-	$ 0.6150	$ -	-	$ 1.5000	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

TOTAL

	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	3,974,155	$ 3.57	$ 14,187,733	3,920,041	$ 0.80	$ 3,136,033	4,005,793	$ 1.86	$ 7,450,775	$ 10,586,808
February	3,872,348	$ 3.57	$ 13,824,282	3,818,005	$ 0.80	$ 3,054,404	3,906,487	$ 1.86	$ 7,266,066	$ 10,320,470
March	3,533,613	$ 3.57	$ 12,614,998	3,487,061	$ 0.80	$ 2,789,649	3,556,102	$ 1.86	$ 6,614,350	$ 9,403,999
April	3,225,020	$ 3.57	$ 11,513,321	3,270,132	$ 0.80	$ 2,616,106	3,330,873	$ 1.86	$ 6,195,424	$ 8,811,529
May	4,203,820	$ 3.57	$ 15,007,637	4,149,759	$ 0.80	$ 3,319,807	4,255,406	$ 1.86	$ 7,915,055	$ 11,234,862
June	4,025,876	$ 3.57	$ 14,372,377	3,946,823	$ 0.80	$ 3,157,458	4,046,593	$ 1.86	$ 7,526,663	$ 10,684,121
July	4,795,334	$ 3.57	$ 17,119,342	4,667,508	$ 0.80	$ 3,734,006	4,763,100	$ 1.86	$ 8,859,366	$ 12,593,372
August	4,541,370	$ 3.57	$ 16,212,691	4,457,988	$ 0.80	$ 3,566,390	4,552,896	$ 1.86	$ 8,468,387	$ 12,034,777
September	4,582,171	$ 3.57	$ 16,358,350	4,426,635	$ 0.80	$ 3,541,308	4,518,575	$ 1.86	$ 8,404,550	$ 11,945,858
October	3,254,324	$ 3.57	$ 11,617,937	3,300,173	$ 0.80	$ 2,640,138	3,382,379	$ 1.86	$ 6,291,225	$ 8,931,363
November	3,537,782	$ 3.57	$ 12,629,882	3,466,344	$ 0.80	$ 2,773,075	3,538,025	$ 1.86	$ 6,580,727	$ 9,353,802
December	4,013,769	$ 3.57	$ 14,329,155	3,877,690	$ 0.80	$ 3,102,152	3,960,416	$ 1.86	$ 7,366,374	$ 10,468,526
Total	47,559,582	$ 3.57	$ 169,787,708	46,788,159	$ 0.80	$ 37,430,527	47,816,645	$ 1.86	$ 88,938,960	$ 126,369,487

Low Voltage Switchgear Credit	8,732,452
	$ 135,101,939

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Unit	Current RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	kWh	$ 0.0070	5,297,958,908	-	$ 37,244,651	23.5%	$ 35,946,150	$ 0.0068
Residential Urban	kWh	$ 0.0070	103,543,333	-	$ 727,910	0.5%	$ 702,532	$ 0.0068
General Service Less Than 50 kW	kWh	$ 0.0068	2,174,128,849	-	$ 14,784,076	9.3%	$ 14,268,643	$ 0.0066
General Service 50 to 999 kW	kW	$ 2.4351	10,189,051,346	26,712,248	$ 65,046,995	41.0%	$ 62,779,191	$ 2.3502
General Service 1,000 to 4,999 kW	kW	$ 2.3527	4,828,382,733	10,972,419	$ 25,814,811	16.3%	$ 24,914,801	$ 2.2707
Large Use	kW	$ 2.6820	2,263,227,585	5,267,224	$ 14,126,694	8.9%	$ 13,634,180	$ 2.5885
Street Lighting	kW	$ 2.1658	112,727,603	321,995	$ 697,376	0.4%	$ 673,063	$ 2.0903
Unmetered Scattered Load	kWh	$ 0.0043	54,056,157	-	$ 231,360	0.1%	$ 223,294	$ 0.0041
					$ 158,673,873			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Unit	Current RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Connectio
Residential	kWh	$ 0.0051	5,297,958,908	-	$ 27,178,529	23.6%	$ 26,668,041	$ 0.0050
Residential Urban	kWh	$ 0.0051	103,543,333	-	$ 531,177	0.5%	$ 521,200	$ 0.0050
General Service Less Than 50 kW	kWh	$ 0.0046	2,174,128,849	-	$ 10,066,217	8.7%	$ 9,877,145	$ 0.0045
General Service 50 to 999 kW	kW	$ 1.7630	10,189,051,346	26,712,248	$ 47,093,693	40.8%	$ 46,209,143	$ 1.7299
General Service 1,000 to 4,999 kW	kW	$ 1.7613	4,828,382,733	10,972,419	$ 19,325,722	16.8%	$ 18,962,731	$ 1.7282
Large Use	kW	$ 1.9567	2,263,227,585	5,267,224	$ 10,306,377	8.9%	$ 10,112,795	$ 1.9199
Street Lighting	kW	$ 2.1022	112,727,603	321,995	$ 676,897	0.6%	$ 664,183	$ 2.0627
Unmetered Scattered Load	kWh	$ 0.0032	54,056,157	-	$ 175,142	0.2%	$ 171,852	$ 0.0032
					$ 115,353,754			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to update the re-align RTS Network Rates to recover forecast wholesale network costs.

Rate Class	Unit	Adjusted RTSR - Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	$ 0.0068	5,297,958,908	-	$ 35,946,150	23.5%	$ 39,853,341	$ 0.0075
Residential Urban	kWh	$ 0.0068	103,543,333	-	$ 702,532	0.5%	$ 778,894	$ 0.0075
General Service Less Than 50 kW	kWh	$ 0.0066	2,174,128,849	-	$ 14,268,643	9.3%	$ 15,819,582	$ 0.0073
General Service 50 to 999 kW	kW	$ 2.3502	10,189,051,346	26,712,248	$ 62,779,191	41.0%	$ 69,603,016	$ 2.6057
General Service 1,000 to 4,999 kW	kW	$ 2.2707	4,828,382,733	10,972,419	$ 24,914,801	16.3%	$ 27,622,931	$ 2.5175
Large Use	kW	$ 2.5885	2,263,227,585	5,267,224	$ 13,634,180	8.9%	$ 15,116,156	$ 2.8699
Street Lighting	kW	$ 2.0903	112,727,603	321,995	$ 673,063	0.4%	$ 746,222	$ 2.3175
Unmetered Scattered Load	kWh	$ 0.0041	54,056,157	-	$ 223,294	0.1%	$ 247,565	$ 0.0046
					$ 153,141,854			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

The purpose of this sheet is to update the re-aligned RTS Connection Rates to recover forecast wholesale connection costs.

Rate Class	Unit	Adjusted RTSR - Connection	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Connectio
Residential	kWh	$ 0.0050	5,297,958,908	-	$ 26,668,041	23.6%	$ 31,831,404	$ 0.0060
Residential Urban	kWh	$ 0.0050	103,543,333	-	$ 521,200	0.5%	$ 622,113	$ 0.0060
General Service Less Than 50 kW	kWh	$ 0.0045	2,174,128,849	-	$ 9,877,145	8.7%	$ 11,789,520	$ 0.0054
General Service 50 to 999 kW	kW	$ 1.7299	10,189,051,346	26,712,248	$ 46,209,143	40.8%	$ 55,155,979	$ 2.0648
General Service 1,000 to 4,999 kW	kW	$ 1.7282	4,828,382,733	10,972,419	$ 18,962,731	16.8%	$ 22,634,222	$ 2.0628
Large Use	kW	$ 1.9199	2,263,227,585	5,267,224	$ 10,112,795	8.9%	$ 12,070,795	$ 2.2917
Street Lighting	kW	$ 2.0627	112,727,603	321,995	$ 664,183	0.6%	$ 792,780	$ 2.4621
Unmetered Scattered Load	kWh	$ 0.0032	54,056,157	-	$ 171,852	0.2%	$ 205,126	$ 0.0038
					$ 113,187,091			

Ontario Energy Board

RTSR WORK FORM FOR ELECTRICITY DISTRIBUTORS

Toronto Hydro-Electric System Limited - EB-2011-0144 - IRM3

For Cost of Service Applicants, please enter the following Proposed RTS rates into your rates model.

For IRM applicants, please enter these rates into the 2012 Rate Generator.

Rate Class	Unit	Proposed RTSR Network		Proposed RTSR Connection	
Residential	kWh	$	0.0075	$	0.0060
Residential Urban	kWh	$	0.0075	$	0.0060
General Service Less Than 50 kW	kWh	$	0.0073	$	0.0054
General Service 50 to 999 kW	kW	$	2.6057	$	2.0648
General Service 1,000 to 4,999 kW	kW	$	2.5175	$	2.0628
Large Use	kW	$	2.8699	$	2.2917
Street Lighting	kW	$	2.3175	$	2.4621
Unmetered Scattered Load	kWh	$	0.0046	$	0.0038

V1.2

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Choose Your Utility:

Toronto Hydro-Electric System Limited
Wasaga Distribution Inc.

Application	EB-2011-0144
OEB Application	IRM3
LDC Licence #:	ED-2002-0497

Application Contact Information

Name:	Anthony Lam
Title:	Economist
Phone Number:	416-542-2876
Email Address:	alam@torontohydro.com
We are applying for rates effective:	June 1, 2012
Last COS Re-based Year	2011

Legend

DROP-DOWN MENU

INPUT FIELD

CALCULATION

Copyright

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Toronto Hydro-Electric System Limited

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Toronto Hydro-Electric System Limited

Enter your 2011 Base Monthly Fixed Charge and Distribution Volumetric Charge into columns labeled "Rate ReBal Base Service Charge" and "Rate ReBal Base Distribution Volumetric Rate kWh/kW" respectively.

Last COS Re-based Year was in 2011

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	598,508	4,886,977,489		18.25	0.0151	
RES	Residential Urban	Customer	kWh	24,898	99,791,184		17.00	0.0257	
GSLT50	General Service Less Than 50 kW	Customer	kWh	65,792	2,139,318,076		24.30	0.0225	
GSGT50	General Service 50 to 999 kW	Customer	kW	13,067	10,116,374,153	26,935,191	35.56		5.5956
GSGT50	General Service 1,000 to 4,999 kW	Customer	kW	514	4,626,928,262	10,587,119	686.46		4.4497
LU	Large Use - Regular	Customer	kW	47	2,376,778,323	4,993,733	3,009.11		4.7406
SL	Street Lighting	Connection	kW	162,777	110,165,016	322,023	1.30		28.7248
USL	Unmetered Scattered Load	Connection	kWh	1,130	56,231,585		4.84	0.0607	
USL	Unmetered Scattered Load	Connection	kWh	21,729	0		0.49		
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Toronto Hydro-Electric System Limited

Calculating Re-Based Revenue from Rates. No input required.

Last COS Re-based Year was in 2011

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Rate ReBal Base Service Charge D	Rate ReBal Base Distribution Volumetric Rate kWh E	Rate ReBal Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I	Service Charge % Revenue K = G / J	Distribution Volumetric Rate % Revenue kWh L = H / J	Distribution Volumetric Rate % Revenue kW M = I / J	Total % Revenue N = J / R
Residential	598,508	4,886,977,489	0	18.25	0.0151	0.0000	131,073,252	73,646,751	0	204,720,003	64.0%	36.0%	0.0%	38.8%
Residential Urban	24,898	99,791,184	0	17.00	0.0257	0.0000	5,079,192	2,559,644	0	7,638,836	66.5%	33.5%	0.0%	1.4%
General Service Less Than 50 kW	65,792	2,139,318,076	0	24.30	0.0225	0.0000	19,184,993	48,070,477	0	67,255,470	28.5%	71.5%	0.0%	12.7%
General Service 50 to 999 kW	13,067	10,116,374,153	26,935,191	35.56	0.0000	5.5956	5,575,758	0	150,718,556	156,294,314	3.6%	0.0%	96.4%	29.6%
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	686.46	0.0000	4.4497	4,234,085	0	47,109,505	51,343,590	8.2%	0.0%	91.8%	9.7%
Large Use - Regular	47	2,376,778,323	4,993,733	3,009.11	0.0000	4.7406	1,697,138	0	23,673,292	25,370,430	6.7%	0.0%	93.3%	4.8%
Street Lighting	162,777	110,165,016	322,023	1.30	0.0000	28.7248	2,539,322	0	9,250,042	11,789,364	21.5%	0.0%	78.5%	2.2%
Unmetered Scattered Load	1,130	56,231,585	0	4.84	0.0607	0.0000	65,611	3,413,257	0	3,478,868	1.9%	98.1%	0.0%	0.7%
Unmetered Scattered Load	21,729	0	0	0.49	0.0000	0.0000	127,767	0	0	127,767	100.0%	0.0%	0.0%	0.0%
							169,577,117	127,690,129	230,751,395	528,018,642				100.0%
							O	P	Q	R				

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Toronto Hydro-Electric System Limited

This worksheet calculates the tax sharing amount.

Step 1: Press the Update Button (this will clear all input cells and reveal your latest cost of service re-basing year).

Summary - Sharing of Tax Change Forecast Amounts

For the 2011 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)	$ 1,010,000	

1. Tax Related Amounts Forecast from Capital Tax Rate Changes

	2011	2012
Taxable Capital	$ -	$ -
Deduction from taxable capital up to $15,000,000	$ -	$ -
Net Taxable Capital	$ -	$ -
Rate	0.000%	0.000%
Ontario Capital Tax (Deductible, not grossed-up)	**$ -**	**$ -**

2. Tax Related Amounts Forecast from Income Tax Rate Changes

	2011	2012
Regulatory Taxable Income	$ 33,651,124	$ 33,651,124
Corporate Tax Rate	28.14%	26.15%
Tax Impact	$ 8,460,203	$ 7,789,334
Grossed-up Tax Amount	**$ 11,791,223**	**$ 10,547,322**

	2011	2012
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ -	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 11,791,223	$ 10,547,322
Total Tax Related Amounts	**$ 11,791,223**	**$ 10,547,322**
Incremental Tax Savings		**-$ 1,243,901**
Sharing of Tax Savings (50%)		**-$ 621,950**

Ontario Energy Board

2012 IRM 3 Tax Savings Workform

Toronto Hydro-Electric System Limited

This worksheet calculates a tax change volumetric rate rider. No input required. The outputs in column Q and S are to be entered into Sheet 17 of the 2012 IRM Rate Generator Model.

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Z-Factor Tax Change$ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$204,720,002.7592	38.77%	-$241,139	4,886,977,489	0	$0.0000	
Residential Urban	$7,638,836	1.45%	-$8,998	99,791,184	0	-$0.0001	
General Service Less Than 50 kW	$67,255,470	12.74%	-$79,220	2,139,318,076	0	$0.0000	
General Service 50 to 999 kW	$156,294,314	29.60%	-$184,098	###########	26,935,191		-$0.0068
General Service 1,000 to 4,999 kW	$51,343,590	9.72%	-$60,477	4,626,928,262	10,587,119		-$0.0057
Large Use - Regular	$25,370,430	4.80%	-$29,884	2,376,778,323	4,993,733		-$0.0060
Street Lighting	$11,789,364	2.23%	-$13,887	110,165,016	322,023		-$0.0431
Unmetered Scattered Load	$3,478,868	0.66%	-$4,098	56,231,585	0	-$0.0001	
Unmetered Scattered Load	$127,767	0.02%	-$150	0	0		
	$528,018,642	100.00%	-$621,950				
	H		- I				

Day of Service - Shared Tax Savings

Rate Class	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kW Rate Rider M = F / J	Service Charge Rate Rider (DOS)	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider (DOS)
Residential		$0.0000		$0.000000	$0.000000	
Residential Urban		-$0.0001		$0.000000	-$0.000100	
General Service Less Than 50 kW		$0.0000		$0.000000	$0.000000	
General Service 50 to 999 kW			-$0.0068	$0.000000		-$0.006700
General Service 1,000 to 4,999 kW			-$0.0057	$0.000000		-$0.005600
Large Use			-$0.0060	$0.000000		-$0.005900
Street Lighting			-$0.0431	$0.000000		-$0.042500
Unmetered Scattered Load		-$0.0001		$0.000000	-$0.000100	
Unmetered Scattered Load				$0.000000		

INCREMENTAL CAPITAL MODULE

THESL seeks the Board's approval for incremental revenue requirements of $26.8 million, $36.0 million and $13.5 million for the years 2012, 2013 and 2014, respectively, to be recovered from customers through fixed and variable rate class specific rate adders over the applicable calendar years commencing June 1, 2012, and May 1 of 2013 and 2014, respectively, related to non-discretionary, incremental capital investments. To the greatest extent possible, THESL request is in accordance with the Board's requirements for the Incremental Capital Module ("ICM") under its IRM plan. The proposed rate adders would result in an increase of approximately $1.54, $2.05, and $0.77, per month in an average residential customer's bill, for 2012, 2013 and 2014, respectively.

THESL's Proposed Capital Expenditures

A summary of THESL's proposed capital expenditures is provided in Appendix 1 to this schedule. This table shows the total level of proposed capital expenditures, including amounts below the materiality threshold, by Project and Project Segment for each year 2012-14.

Detailed Business Case descriptions of the proposed capital expenditures for each Segment are provided in Schedules B and C. Reviews by third party consultants of the Business Cases and THESL's approach to Asset Management are provided in Schedule D.

To determine the rate riders resulting from the proposed ICM capital expenditures, THESL has populated the ICM Workforms (E Schedules) using the details from the individual ICM Worksheets for each Segment (F Schedules), for each year.

Summary of Capital Program

Schedule Number	Projects	Segments	Cost Estimates ($M) 2012	2013	2014	Total
B1	Underground Infrastructure and Cable	Underground Infrastructure	46.94	53.02	74.92	174.88
B2		Paper Insulated Lead Covered Cable - Piece Outs and Leakers	17.32	5.18	1.47	23.97
B3		Handwell Replacement	12.01	14.45	7.17	33.63
B4	Overhead Infrastructure and Equipment	Overhead Infrastructure	29.43	53.02	20.11	102.56
B5		Box Construction	10.20	20.54	27.76	58.50
B6		Rear Lot Construction	34.37	20.73	11.03	66.13
B7		Polymer SMD-20 Switches	3.06	2.95	2.94	8.94
B8		SCADA-Mate R1 Switches	2.86	2.80	2.69	8.36
B9	Network Infrastructure and Equipment	Network Vault & Roofs	13.57	12.31	15.57	41.45
B10		Fibertop Network Units	8.59	8.78	9.36	26.73
B11		Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	3.27	3.30	3.23	9.80
B12	Station Infrastructure and Equipment	Stations Power Transformers	1.30	2.56	0.87	4.73
B13.1 & 13.2		Stations Switchgear - Muncipal and Transformer Stations	19.35	18.76	20.31	58.41
B14		Stations Circuit Breakers	1.37	1.08	1.38	3.83
B15		Stations Control & Communicaton Systems	1.15	2.15	1.34	4.64
B16		Downtown Station Load Transfers	1.75	1.59	3.59	6.93
B17	Bremner TS	Bremner Transformer Station	31.73	69.38	23.02	124.13
B18	Hydro One Capital Contributions	Hydro One Capital Contributions	25.28	52.12	36.00	113.40
B19	Feeder Automation	Feeder Automation	7.82	16.30	7.38	31.50
B20	Metering	Metering	5.62	7.21	10.03	22.85
B21	Plant Relocations	Externally-Initiated Plant Relocations and Expansions	24.27	17.67	13.34	55.28
B22	Grid Solutions	Grid Solutions	2.40	3.60	0.96	6.95
C1	Operations Portfolio Capital		121.70	121.60	121.60	364.90
C2	Information Technology Capital		15.00	15.00	15.00	45.00
C3	Fleet Capital		2.00	2.00	2.00	6.00
C4	Buildings and Facilities Capital		5.00	5.00	5.00	15.00
	Allowance for Funds Used During Construction		1.40	1.40	1.40	4.20
Total			**448.74**	**534.48**	**439.47**	**1,422.70**

ICM Project – Underground Infrastructure and Cable

Underground Infrastructure Segment

Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

1. Project Description

This segment includes 38 discrete jobs to replace approximately $174.88 million of direct buried cable with cable in concrete-encased ducts, and air-insulated pad-mounted switchgear units with SF_6-insulated pad-mounted switchgear units in 2012, 2013, and 2014. The cost breakdown by year is $46.94 million in 2012, $53.02 million in 2013, and $74.92 million in 2014. The jobs address both direct buried cable and air-insulated pad-mounted switchgear units collectively, as this is the most efficient and cost-effective approach. Table 1 below lists the proposed jobs, in order of the number of unplanned sustained outages[1] experienced by the feeder in 2011 (with the exception of the last job in the table because it addresses a number of feeders). Each job is described in section II.

Table 1: List of jobs to be executed in 2012, 2013 and 2014

Job Title	Year	Estimated Cost ($M)
Underground Rehabilitation of Feeder NY80M29	2012, 2013	$2.90
Underground Rehabilitation of Feeder SCNAR26M34	2012, 2013, 2014	$5.52
Underground Rehabilitation of Feeder NY55M8	2012	$2.49
Underground Rehabilitation of Feeder YK35M10	2012	$2.14
Underground Rehabilitation of Feeder SCNT63M4	2014	$3.16
Underground Rehabilitation of Feeder SCNA47M14	2012, 2013	$4.43
Underground Rehabilitation of Feeder NY51M6	2012, 2013	$2.54
Underground Rehabilitation of Feeder NY80M8	2014	$9.51
Underground Rehabilitation of Feeder NY85M6	2014	$2.01
Underground Rehabilitation of Feeder NY51M8	2013, 2014	$1.58
Underground Rehabilitation of Feeder SCNA502M22	2012, 2013, 2014	$2.96
Underground Rehabilitation of Feeder SCNAH9M30	2013, 2014	$3.56

[1] A sustained outage is an outage lasting more than one minute.

Job Title	Year	Estimated Cost ($M)
Underground Rehabilitation of Feeder NY85M4	2013, 2014	$8.27
Underground Rehabilitation of Feeder SCNA47M13	2013, 2014	$4.91
Underground Rehabilitation of Feeder NY80M2	2013	$1.63
Underground Rehabilitation of Feeder NY51M7	2013	$1.40
Underground Rehabilitation of Feeder NY51M24	2013, 2014	$5.64
Underground Rehabilitation of Feeder NY80M30	2012	$8.95
Underground Rehabilitation of Feeder NY55M23	2014	$2.24
Underground Rehabilitation of Feeder NY85M24	2014	$2.03
Underground Rehabilitation of Feeder SCNAE5-2M3	2013	$1.51
Underground Rehabilitation of Feeder NY85M7	2014	$13.83
Underground Rehabilitation of Feeder SCNT63M12	2012, 2013, 2014	$11.14
Underground Rehabilitation of Feeder SCNT63M8	2013, 2014	$7.59
Underground Rehabilitation of Feeder SCNAE5-1M29	2012, 2013	$3.91
Underground Rehabilitation of Feeder NY53M25	2012, 2013	$3.44
Underground Rehabilitation of Feeder NY80M9	2014	$2.21
Underground Rehabilitation of Feeder SCNT47M3	2012, 2013, 2014	$20.44
Underground Rehabilitation of Feeder SCNAH9M23	2014	$2.71
Underground Rehabilitation of Feeder NY51M3	2013, 2014	$3.54
Underground Rehabilitation of Feeder SCNA47M17	2013, 2014	$5.70
Underground Rehabilitation of Feeder SCNA502M21	2013, 2014	$3.44
Underground Rehabilitation of Feeder SCNT47M1	2012, 2013, 2014	$14.91
Underground Rehabilitation of Feeders NY85M1, NY85M9 and NYSS58F1	2012, 2013	$2.66
	Total	**$174.88**

2. Why the Work is Needed Now

Direct buried (DB) cross-linked polyethylene (XLPE) cables and air-insulated pad-mounted switches both represent critical assets within the underground distribution system. Both of these assets have been identified as carrying significant reliability as well as safety risks that are inherent in past installation practices as well as overall design. Based on specific failure modes, incidents, reliability, and performance information pertaining to these assets, THESL has determined that replacement jobs for these assets must be executed in the next three years.

The number of interruptions due to direct buried cable failures has exhibited an increasing trend since 2000, as illustrated in Figure 1. The slight improvement between 2007 and 2010 was due to direct buried cable replacement activities that started in 2007. Approximately 887 circuit kilometres of direct buried cable remain in THESL's system, representing approximately 7% of all underground primary cable in THESL's distribution grid. Of the circuit 887 kilometres, approximately 580 circuit kilometres require immediate attention.

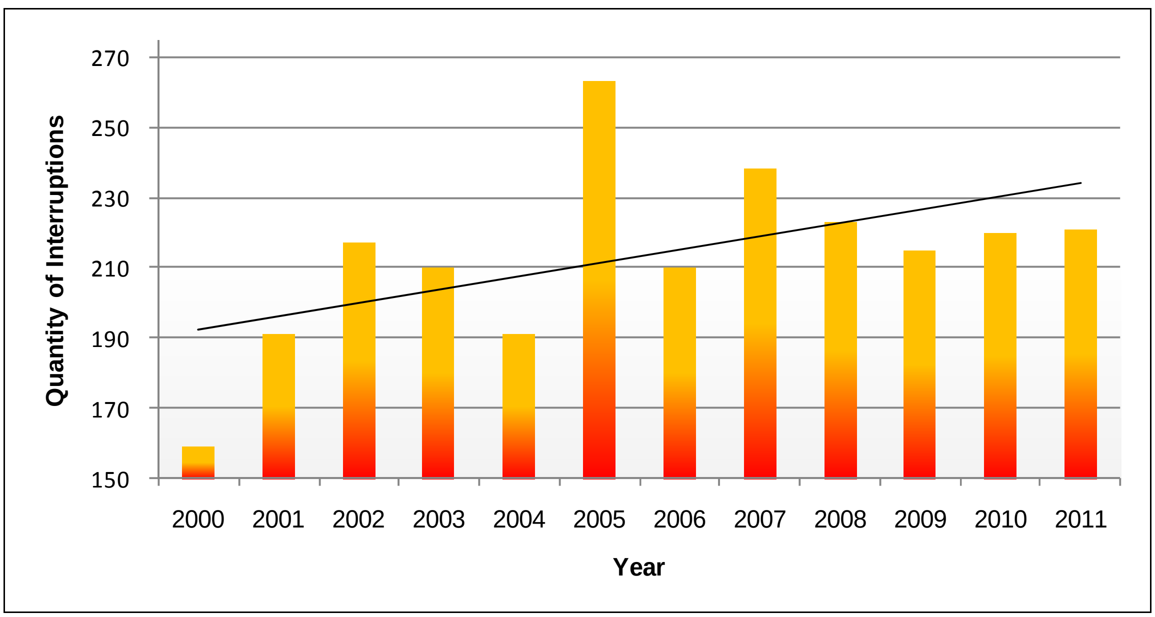


Figure 1: Number of interruptions attributed to direct buried cable failures.

In 2011, Customers Interrupted (CI) and Customer Hours Interrupted (CHI) values for direct buried cables accounted for 57% and 43% respectively of the CI and CHI for the entire underground distribution system.

Air-insulated pad-mounted switches show an increasing failure trend over the past ten year period, as is evident from Figure 2. As these assets are typically connected to one or multiple feeder trunk circuits, a typical failure will impact 1,400 customers for an average duration of 50 minutes. Attempts to limit these failures via proactive cleaning activities may actually be further degrading these assets over time. Ultimately, it is the open-air design of these assets that allows for contamination to occur, leading to a flashover and posing a potentially serious safety hazard to field crews.

Should further proactive replacement activities for air-insulated pad-mounted switches be discontinued, failures are expected to increase sharply.

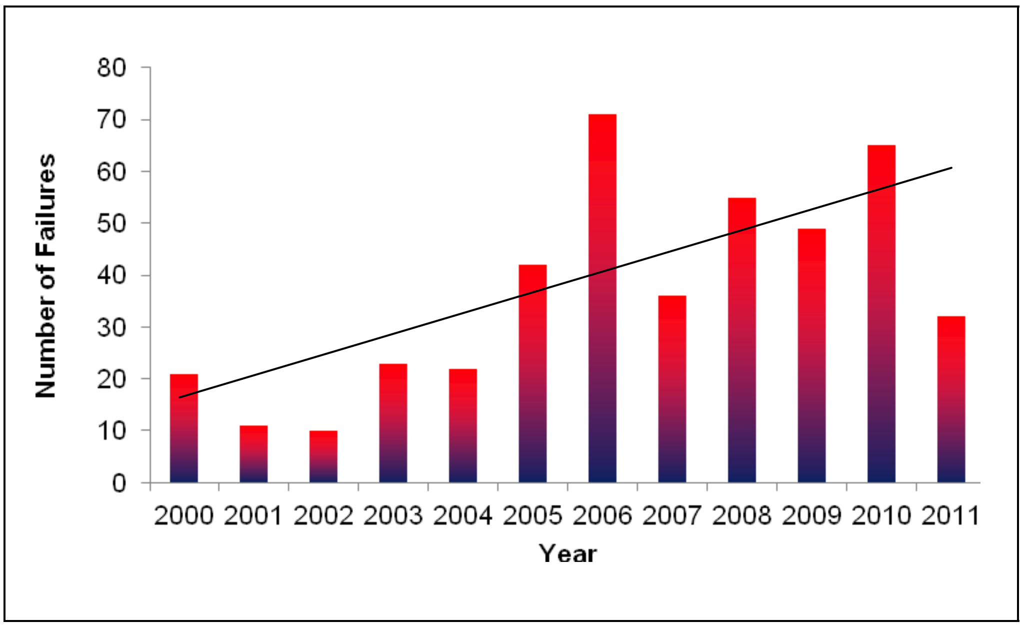


Figure 2: Air-insulated Pad-Mounted Switch Failure Rate

3. Why the Proposed Work is the Preferred Alternative

Intervention options for direct buried XLPE cables include: the rejuvenation of these cables with cable rejuvenation fluids; replacement of these cables with new strand-blocked tree-retardant XLPE (TR-XLPE) direct buried cables; and finally, replacement of these cables with new strand-blocked TR-XLPE cables installed within concrete-encased conduit.

Due to numerous operational issues associated with rejuvenation including the planned outage time required and the fact that splicing/repair activities would need to continue as part of outage remediation, THESL has concluded that cable rejuvenation is not a viable option (See Section IV, 1, Option 2). The same conclusion was reached for replacing direct buried XLPE cables with new direct buried TR-XLPE cables (See Section IV, 1, Option 3). With both of these options, there would be a continuing probability of failure due to the fact that the cables remain direct buried and the remediation costs would still be significant due to digging and splicing activities required.

Replacement of direct buried XLPE cables with new strand-blocked TR-XLPE cables in concrete-encased conduit is the preferred alternative (See Section IV, 1, Option 4). The conduit provides mechanical protection against external factors and moisture from the surrounding soil. Moreover, an entire cable segment can be pulled out from the conduit and replaced with a new cable segment during remediation procedures. This is in stark contrast to outage remediation for direct buried cables, in which case cables are spliced and will therefore continue deteriorating along their existing life cycle from the time of failure onwards. The life cycle will be further shortened due to the fact that the splice in itself may become a point of failure.

There are also a number of intervention options available for existing air-insulated pad-mounted switches (See Section IV, 2, Options 1 through 5). Maintenance activities, including CO_2 cleaning, can be accelerated for this asset class, but it has been noted that these cleaning activities are also resulting in further degradation of the asset over time (See Section IV, 2, Option 1).

A pilot study was carried out to install a moisture barrier within an air-insulated pad-mounted switch to isolate the below-grade contaminants from the above-grade electrical parts (See Section IV, 2, Option 3). However, the vast majority of contamination occurs through the ventilation louvers of the asset, which are above this barrier. Furthermore, the barrier provides an additional medium for water and contamination to settle upon, thus increasing the probability of a flashover occurrence.

These assets may also be replaced with an air-insulated Pad-Mounted Enclosed (PME) switch, which features a dead-front design keeping live connections away from the crew workers (See Section IV, 2, Option 4). While this design reduces potential safety risks, it also possesses the very same open-air design that permits for contamination, and ultimately flashovers to take place.

Ultimately, replacement of air-insulated pad-mounted switches with SF_6-insulated pad-mounted switches is the preferred alternative. These non-air-insulated pad-mounted switches offer a sealed-type design in which all electrical components are encapsulated within a dielectric medium. As a result, there is no way for contaminants to gain entry into this enclosure. Additionally, these assets do not require CO_2 cleaning due to their design.

In conclusion, the most prudent approach is to replace direct buried XLPE cables with new TR-XLPE cables in concrete-encased conduit and air-insulated pad-mounted switches with SF_6-insulated pad-mounted switches as part of a single project. This comprehensive approach allows THESL to rebuild entire distribution loops or sections of a feeder. The job planning and execution efficiencies associated with this comprehensive approach more than outweigh the higher avoided risk costs associated with an individual asset replacement approach as discussed in Appendix F.

II DESCRIPTION OF WORK

Direct buried (DB) cross-linked polyethylene (XLPE) cables and air-insulated pad-mounted switches both represent critical assets within the underground distribution system. Both of these assets have been identified as carrying significant reliability and safety risks, inherent to past installation practices as well as overall design. Based on factors such as specific failure modes, safety incidents, reliability, and asset performance, it has been determined that approximately $162 million of underground infrastructure rehabilitation is required from 2012 to 2014 to address direct buried cable and air-insulated pad-mounted switchgear.

As will be further discussed in later sections, direct buried XLPE cables are not only past their useful service life, but due to the specific method of installation (i.e., directly buried in the ground) these cables are experiencing hydrothermal aging and failing at a higher than anticipated rate. As detailed in section III below, direct buried cable failures have a significant impact on the reliability of THESL's grid.

Air-insulated pad-mounted switchgear units have also been failing at an accelerated rate. The design of these switchgear units allows for contamination and moisture to easily accumulate in the switching compartment, resulting in premature failure. These switchgear units present potential safety risks due to their live-front design and failure mode. The failure of an air-insulated pad-mounted switch can have a significant impact on reliability as these switches are often used to tie together multiple circuits. The most prudent solution, detailed below, is to replace air-insulated pad-mounted switchgear with SF_6-insulated pad-mounted switchgear.

The underground infrastructure rehabilitation jobs to replace direct buried cable and air-insulated distribution switchgear with cable in concrete-encased ducts and SF_6-insulated distribution switchgear, respectively, have been selected based on feeders experiencing the worst reliability. Each job, with the exception of one, targets the assets of one feeder (as indicated in the title of each job), thereby focusing on improving the condition and reliability of that feeder.

To achieve maximum job cost-effectiveness, THESL proposes that replacement of air-insulated distribution switchgear is to be completed alongside replacement of direct buried cable in the same job area. Also, where cost-effective, THESL proposes that non-standard submersible transformers will be replaced with new standard submersible transformers and air-insulated vault-installed switchgear will be replaced with SF_6-insulated vault-installed switchgear as a part of these jobs.

The majority of jobs are also made up of sub-jobs. The year of execution of a sub-job is selected based on one or more of the following factors:

- Urgency – repeated asset failures that need to be addressed
- Dependency of sub-job phases – the most common example is that the electrical phase of a sub-job must follow the civil phase
- Coordination with City of Toronto road construction
- Coordination with neighbourhood rehabilitation – the most common example is coordinating with townhouse complexes that are undergoing rehabilitation or renovation

It should be noted that the customers interrupted (CI) and customer hours interrupted (CHI) data presented in the tables in the job descriptions exclude loss of supply, major event days (MED) and planned outages, thereby more accurately reflecting the reliability of the distribution assets.

1. Underground Rehabilitation of Feeder NY80M29 (E12206, E12226, E12227, E12656, E12666)

1.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY80M29 in order to improve reliability of service and mitigate potential safety risks.

1.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 15

Of the 15 unplanned sustained outages in 2011, five were related to primary cable failures. This job rebuilds areas that have experienced direct buried cable failures. Table 2 provides historical reliability data for this feeder.

Table 2: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY80M29			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	10,473	2,430	8,255
Feeder CHI ***(Cumulative)***	3,704	1,631	2,294

1.3. Scope of Work

This job replaces both civil and electrical assets. Direct-buried cable, air-insulated switchgear, and non-standard submersible transformers are being replaced in this job with 28kV Aluminum TR-XLPE cable in concrete-encased ducts, SF_6-insulated switchgear, and submersible transformers.

Table 3: Asset Replacement

Assets to be Replaced		**New Assets to be Installed**	
Primary Cable	16,100 m	Primary Cable	16,100 m
Air-insulated Pad-mounted Switchgear	3	SF_6-insulated Pad-mounted Switchgear	3
Air-insulated Vault-installed Switchgear	9	SF_6-insulated Vault-installed Switchgear	9
Submersible Transformers	12	Submersible Transformers	12

1.4. Map and Locations

The assets being replaced by this job are located in the area bordered by Bayview Avenue to the east, Yonge Street to the west, Sheppard Avenue East to the north, and York Mills Road to the south. A map of the area appears in Figure 1 below.

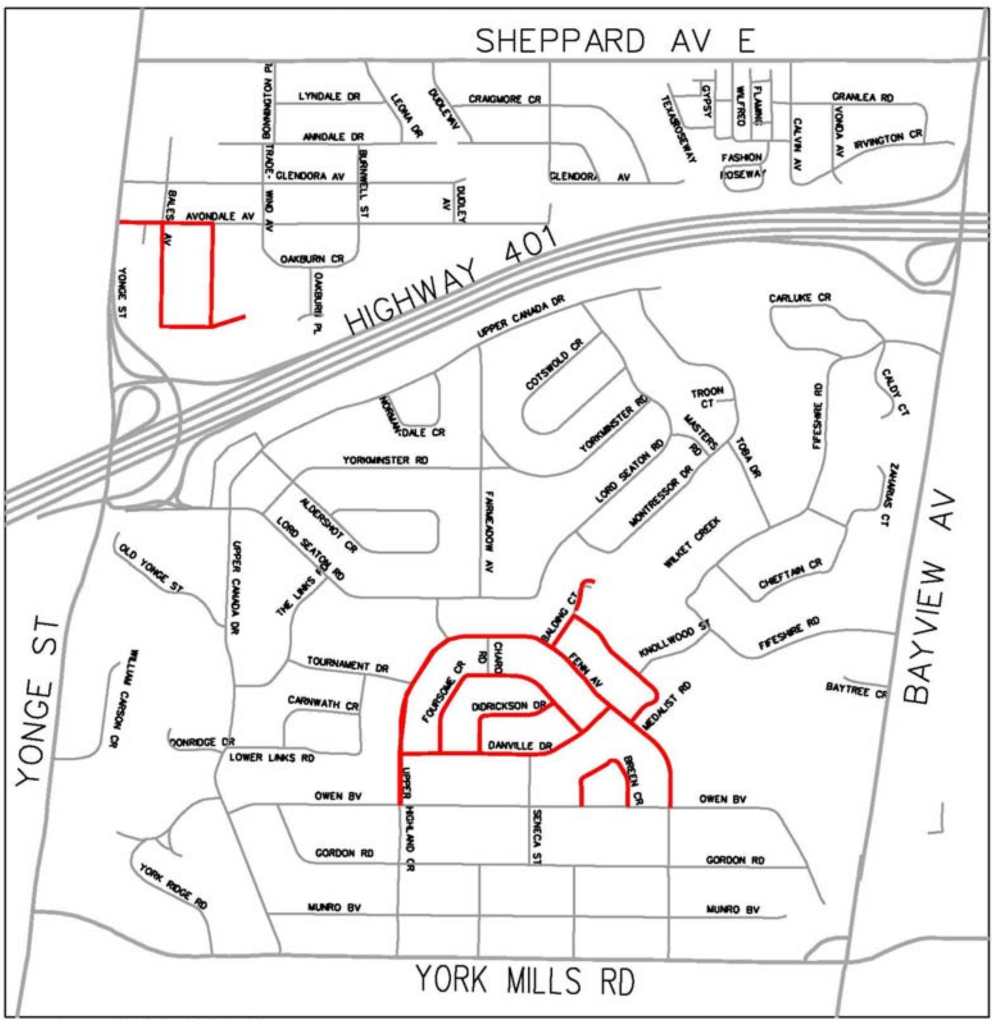


Figure 3: Map of Underground Rehabilitation of Feeder NY80M29

1.5. Required Capital Costs

There are five phases to this job with a total estimated cost of $2.90M.

Table 4: Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20043	E12206 NY80M29 Fenn/Foursome UG DB Rebuild Civil	2012	$1.28
19464	E12226 NY80M27/29 Yorkminster UG Tie Elec	2012	$0.54
20044	E12227 NY80M29 Fenn/Foursome UG DB Rebuild Elect	2013	$0.43
23241	E12656 UG Cable Replacement NY80M29 Harrison Garden West	2012	$0.49
23556	E12666 Phase 1 Reconfigure FESI 80M29 -Harrison Garden	2012	$0.16
		Total:	**$2.90**

2. Underground Rehabilitation of Feeder SCNAR26M34 (E11544, E12121, E12153, E13289, E14321 and E14322)

2.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNAR26M34 in order to improve reliability of service and mitigate potential safety risks.

2.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 12

As evident from Table 5, this feeder has been experiencing increasingly poor reliability over the past three years. This poor reliability is partially due to failures of underground assets, including direct buried cable. This job rebuilds areas that have experienced underground asset failures.

Table 5: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNAR26M34			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	1,183	9,101	7,560
Feeder CHI ***(Cumulative)***	7,221	5,567	14,616

2.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 6: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	8,250 m	Primary Cable	8,250 m
Submersible Transformers	18	Submersible Transformers	18
Air-insulated Pad-mounted Switchgear	4	SF_6-insulated Pad-mounted Switchgear	4
Air-insulated Vault-installed Switchgear	61	SF_6-insulated Vault-installed Switchgear	61

2.4. Map and Locations

The assets being replaced by this job are located in the area bordered by Neilson Road to the east, Markham Road to the west, Finch Avenue East to the north, and Sheppard Avenue to the south. A map of the job area appears in Figure 4 below.

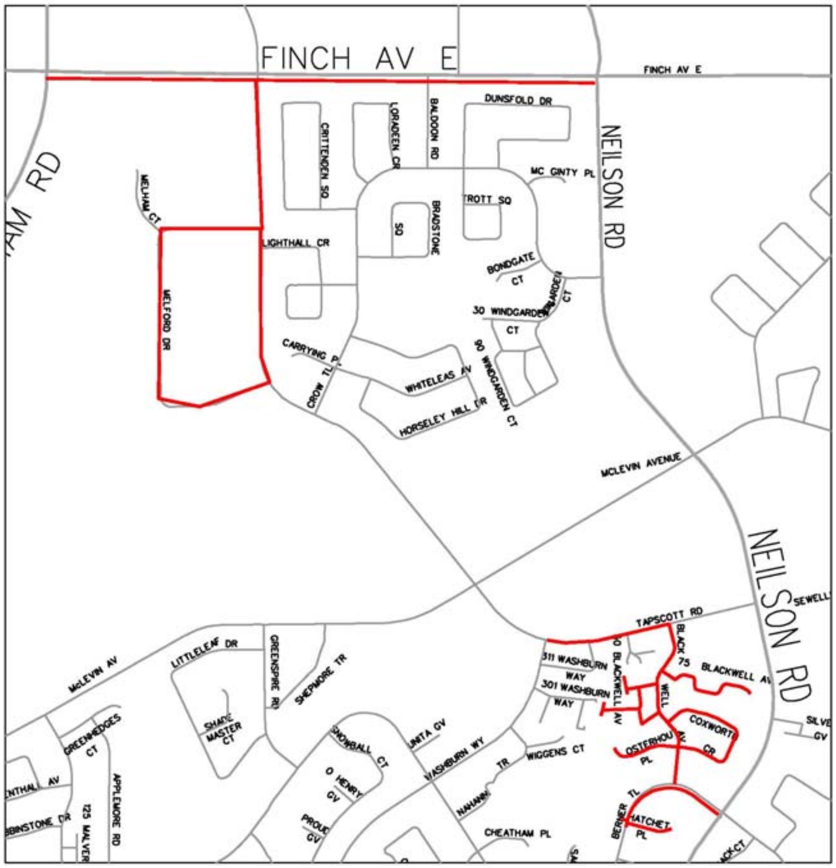


Figure 4: Map of Underground Rehabilitation of Feeder SCNAR26M34

2.5. Required Capital Costs

There are six phases to this job with a total estimated cost of $5.52M.

Table 7: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
24850	E11544 Rebuild Blackwell Coxworth UG (Civil)	2012	$1.38
24852	E12121 Rebuild Blackwell Coxworth UG (Electrical)	2013	$0.48
24500	E12153 Melford Distribution Feeder Transfer from R26M34	2012	$0.47
22718	E13289 UG Rebuild R26M34 Melford Customer Vaults	2013	$1.60
24149	E14321 Establish Neilson Tapscott R26M34 Main - Civil	2014	$1.06
24150	E14322 Establish Neilson Tapscott R26M34 Main - Electrical	2014	$0.54
		Total:	**$5.52**

3. Underground Rehabilitation of Feeder NY55M8 (W11385)

3.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY55M8 in order to improve reliability of service and mitigate potential safety risks.

3.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 12

As is evident from Table 8, the reliability of this feeder is poor. The majority of outages on this feeder are related to asset failures, and the majority of asset failures are underground asset failures.

Table 8: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY55M8			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	15,626	6,227	10,734
Feeder CHI ***(Cumulative)***	6,944	3,920	8,973

3.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced are direct buried cable and submersible transformers.

Table 9: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	7,500 m	Primary Cable	7,500 m
Submersible Transformers	31	Submersible Transformers	31

3.4. Maps and Locations

The assets being replaced by this job are in the area northeast of the intersection of Jane Street and Sheppard Avenue West. A map of the job area appears in Figure 5.

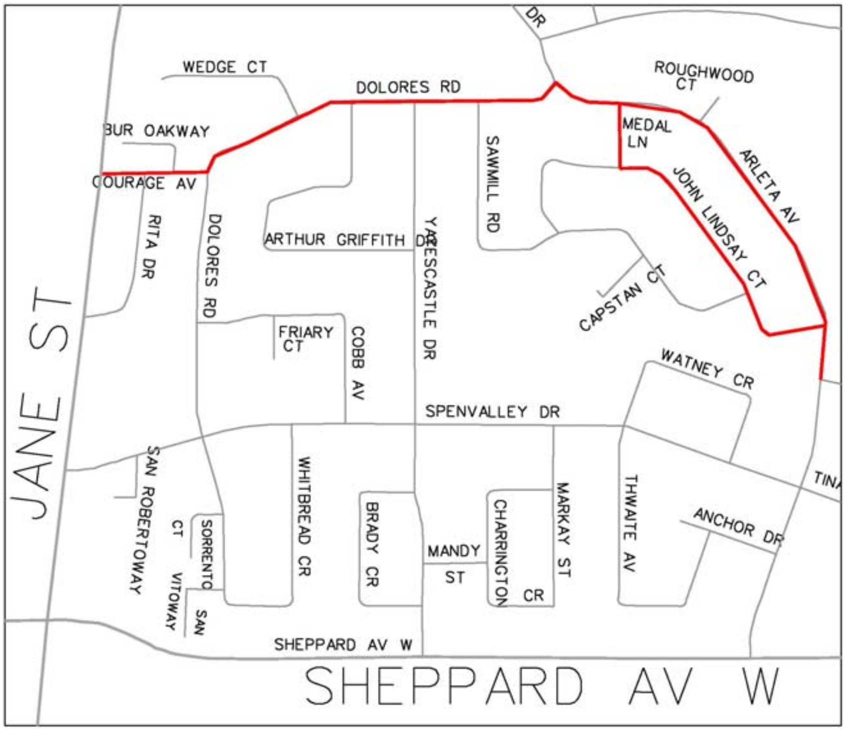


Figure 5: Map of Underground Rehabilitation of Feeder NY55M8

3.5. Required Capital Costs

Table 10: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
18585	W11385 FESI 55M8 Northwoods Sub UG Cable and Rebuild	2012	$2.49
		Total:	**$2.49**

4. Underground Rehabilitation of Feeder YK35M10 (X11444)

4.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder YK35M10 in order to improve reliability of service and mitigate potential safety risks.

4.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 11

This feeder has been experiencing poor reliability for the past ten years. Table 11 provides reliability data for this feeder for 2009, 2010 and 2011.

Table 11: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – YK35M10			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	12,687	3,289	17,593
Feeder CHI ***(Cumulative)***	4,099	548	2,333

This job rebuilds a section of the feeder that has experienced a direct buried cable failure.

4.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts to replace old direct-buried cable.

Table 12: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	3,500 m	Primary Cable	3,500 m

4.4. Map and Locations

The assets being replaced by this job are located in the area bordered by Spadina Road to the east, Bathurst Street to the west, Tichester Road to the north, and St. Clair Avenue West to the south. A map of the job area appears in Figure 6 below.

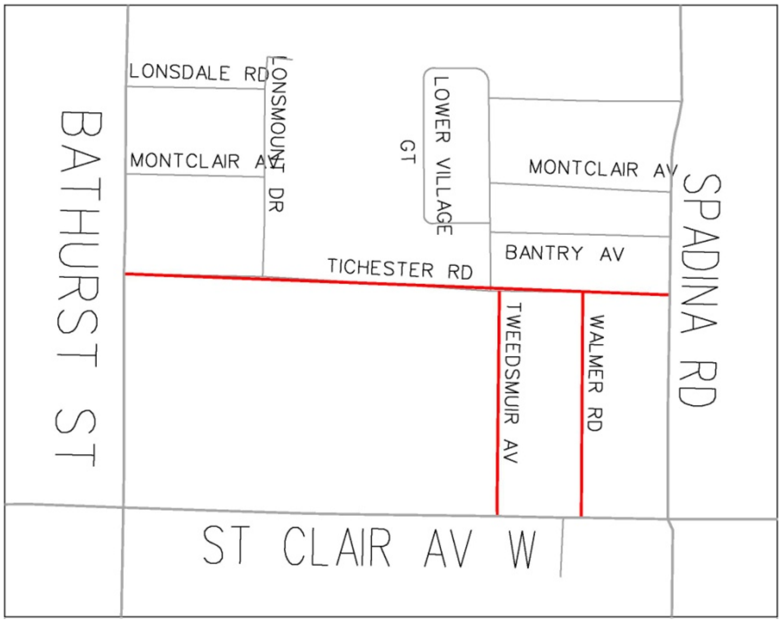


Figure 6: Map of Underground Rehabilitation of Feeder YK35M10

4.5. Required Capital Cost

Table 13: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
18675	Tichester and surrounding civil electrical enhancement 35M10/35M9	2012	$2.14
		Total:	**$2.14**

5. Underground Rehabilitation of Feeder SCNT63M4 (E14327, E14330)

5.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNT63M4 to improve reliability of service and mitigate potential safety risks.

5.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 10

Historically, the majority of asset related sustained outages on this feeder have been due to the failure of underground assets. Underground asset failures accounted for approximately 50% of the CI and CHI in 2011. Table 14 provides reliability data for this feeder for 2009, 2010 and 2011.

Table 14: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNT63M4			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	397	230	28,124
Feeder CHI ***(Cumulative)***	131	649	22,102

5.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 15: Asset Replacement

Assets to be Replaced		**New Assets to be Installed**	
Primary Cable	13,750m	Primary Cable	13,750m
Submersible Transformers	1	Submersible Transformers	1
Air-insulated Pad-mounted Switchgear	7	SF_6-insulated Pad-mounted Switchgear	7
Air-insulated Vault-installed Switchgear	4	SF_6-insulated Vault-installed Switchgear	4

5.4. Map and Locations

The assets being replaced by this job are located in the area bordered by Brimley Road to the east, Midland Avenue to the west, Steeles Avenue East to the north, and McNicoll Avenue to the south. A map of the job area appears in Figure 7 below.

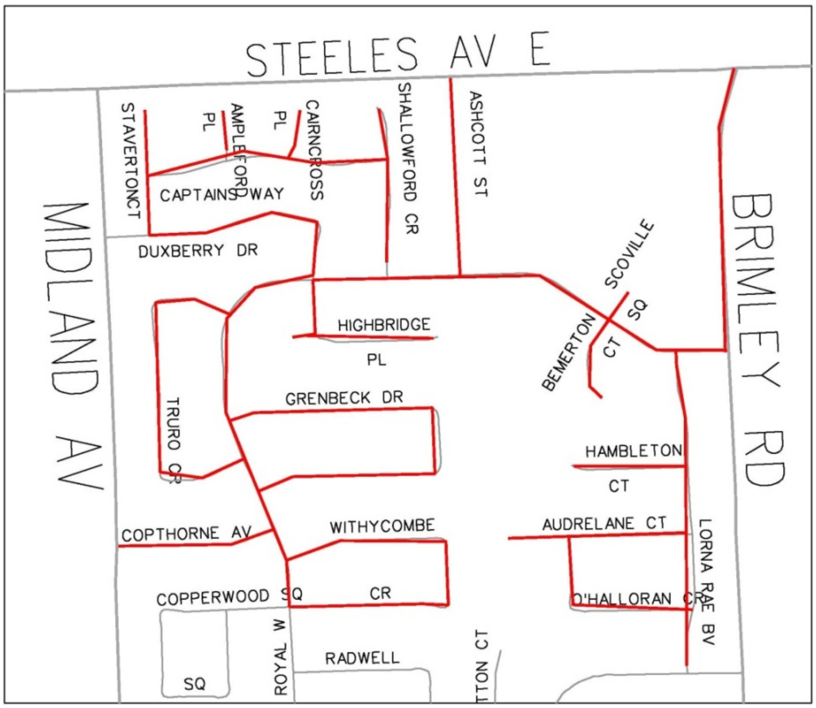


Figure 7: Map of Underground Rehabilitation of Feeder SCNT63M4

5.5. Required Capital Costs

There are two phases to this job for a total estimated cost of $3.16M.

Table 16: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
24224	E14327-P01 Port Royal N UG Reconfigure Main Civ Agincourt TS SCNT63M4	2014	$2.20
24225	E14330-P01 Port Royal N UG Reconfigure Main Elec Agincourt TS SCNT63M4	2014	$0.96
		Total:	**$3.16**

6. Underground Rehabilitation of Feeder SCNA47M14 (E12529, E12530, E13060, E13061, E13063 and E13064)

6.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNA47M14 in order to improve reliability of service and mitigate potential safety risks.

6.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 10

This feeder has been experiencing increasingly poor reliability, with the majority of asset related sustained outages due to the failure of underground assets. Table 17 provides historical reliability data for this feeder.

Table 17: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNA47M14			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	4,076	14,227	11,491
Feeder CHI ***(Cumulative)***	3,365	7,658	7,586

This job rebuilds sections of the feeder where there have been direct buried cable failures.

6.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 18: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	6,500 m	Primary Cable	6,500 m
Submersible Transformers	37	Submersible Transformers	37

6.4. Maps and Locations

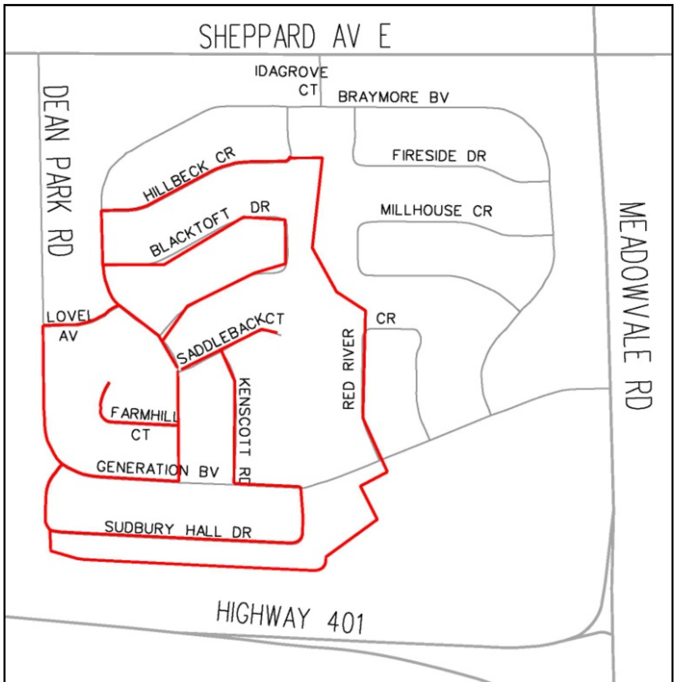
The assets being replaced by this job are located in two areas. One area is bordered by Meadowvale Road to the east, Morningside Avenue to the west, Sheppard Avenue East to the north, and Kingston Road to the south. The other area is bordered by Port Union Road to the east, Centennial Road to the west, Lawson Road to the north, and Lawrence Avenue East to the south. Maps of the job areas appear in Figure 8 below.

6.5. Required Capital Costs

There are six phases to this job for a total estimated cost of $4.43M.

1 **Table 19: Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21139	E13060 141 Galloway UG Rebuild Civil	2013	$0.20
21141	E13061 141 Galloway UG Rebuild Electrical	2013	$0.23
24856	E12529 Braymore W 47M14 UG Rebuild Ph 2 - Civil	2012	$2.77
24859	E12530 Braymore W 47M14 UG Rebuild Ph 2 – Electrical	2013	$0.68
21167	E13064 Rodda UG Rebuild Electrical	2013	$0.45
21166	E13063 Rodda UG Rebuild Civil	2013	$0.11
		Total:	**$4.43**



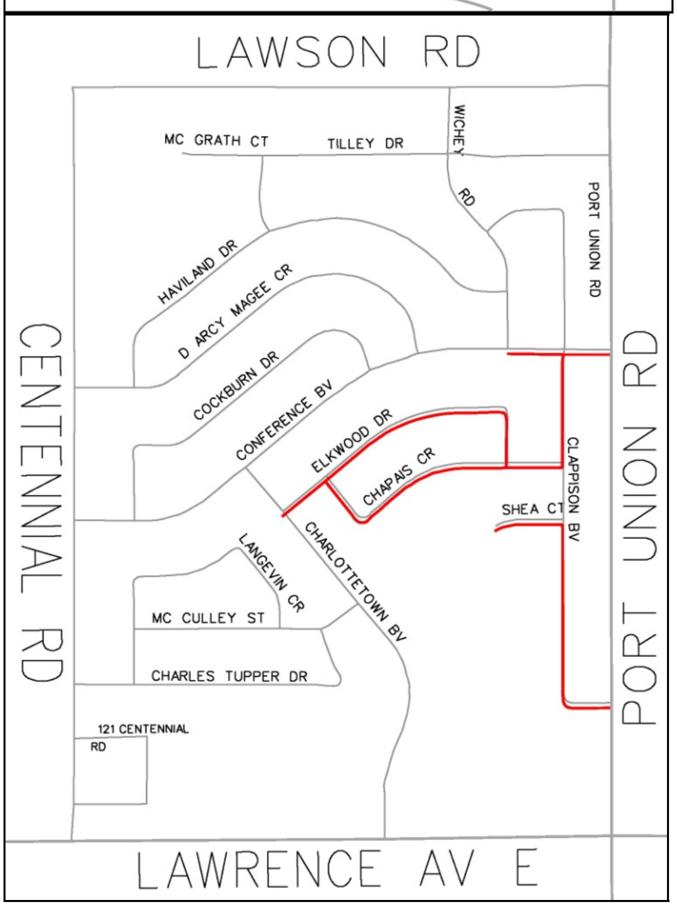


Figure 8: Maps of Underground Rehabilitation of Feeder SCNA47M14

7. Underground Rehabilitation of Feeder NY51M6 (E11592, E11593)

7.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY51M6 in order to improve reliability of service and mitigate potential safety risks.

7.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 10

This feeder has been experiencing poor reliability, as is clear from Table 20. The majority of asset related sustained outages over the past ten years have been due to the failure of underground assets. Over the past five years, there have been 15 primary cable failures on this feeder.

Table 20: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY51M6			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	7,099	5,131	5,408
Feeder CHI ***(Cumulative)***	6,992	2,937	8,758

7.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new SF_6-insulated switchgear. Assets to be replaced include direct-buried cable and air-insulated switchgear.

Table 21: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	13,300 m	Primary Cable	13,300 m
Air-insulated Pad-mounted Switchgear	6	SF_6-insulated Pad-mounted Switchgear	6
Air-insulated Vault-installed Switchgear	12	SF_6-insulated Vault-installed Switchgear	12

7.4. Maps and Locations

The assets being replaced by this job are located along Leslie Street from Sheppard Avenue East to just north of Finch Avenue East. A map of the job area appears in Figure 9 below.

7.5. Required Capital Costs

There are two phases to this job for a total estimated cost of $2.54M.

Table 22: Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21551	E11593 FESI-12 NY51M6 Leslie/Nymark UG Cable Rehab Ph1	2012	$0.70
22424	E11592 FESI-12 NY51M6 Leslie/Nymark UG Cable Rehab Prt2	2013	$1.84
		Total:	**$2.54**

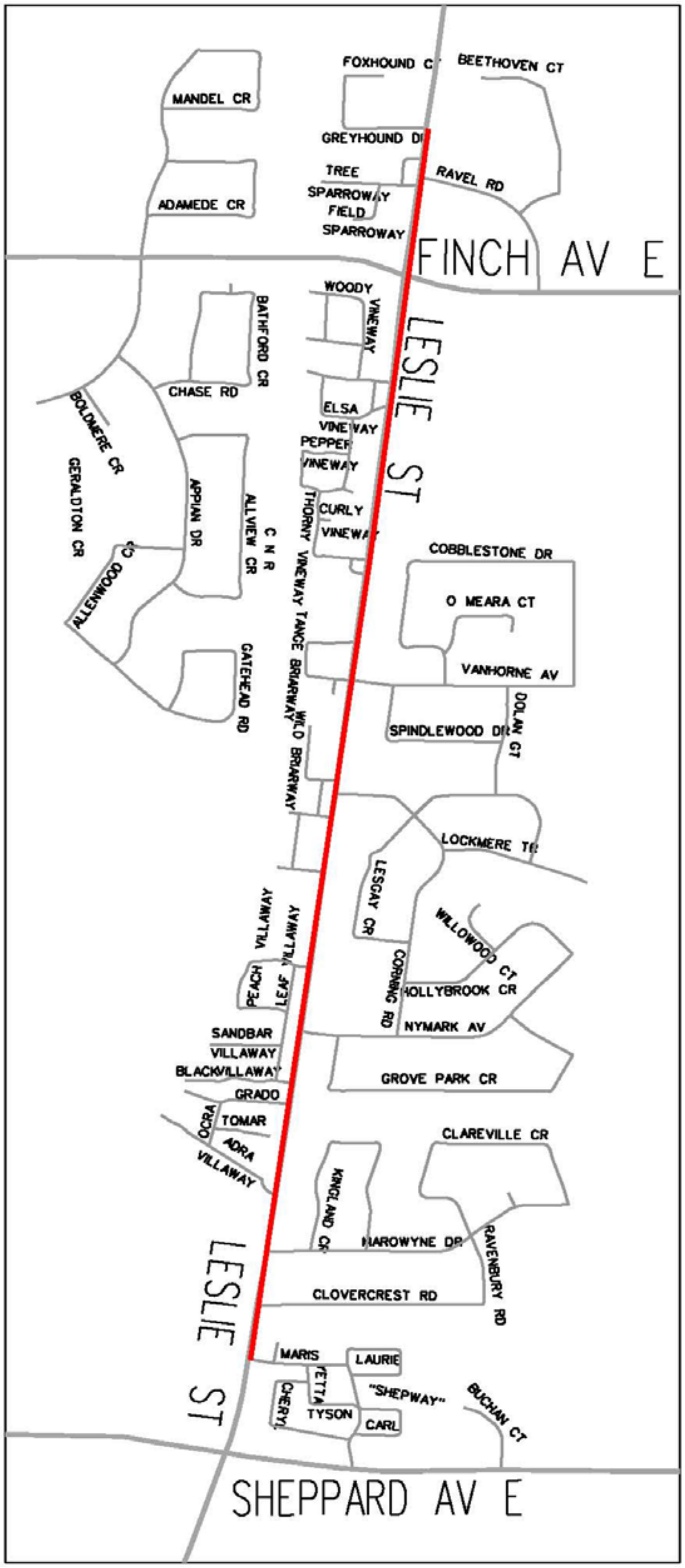


Figure 9: Map of Underground Rehabilitation of Feeder NY51M6

8. Underground Rehabilitation of Feeder NY80M8 (W12464, W14229, W14248)

8.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY80M8 in order to improve reliability of service and mitigate potential safety risks.

8.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 8

Table 23 provides historical reliability data for this feeder. While the table seems to indicate slightly improving reliability over the past three years, this feeder experienced a large number of unplanned sustained outages in 2011 – eight. Half of these unplanned sustained outages were due to failures related to underground primary cable.

Table 23: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY80M8			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	4,622	4,616	3,004
Feeder CHI ***(Cumulative)***	5,144	3,768	2,975

This job rebuilds an area that has experienced multiple direct buried cable failures.

8.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 24: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	11,000 m	Primary Cable	11,000 m
Submersible Transformers	18	Submersible Transformers	18
Air-insulated Pad-mounted Switchgear	1	SF_6-insulated Pad-mounted Switchgear	1

8.4. Maps and Locations

The assets being replaced by this job are located in the area northwest of the intersection of Bathurst Street and Finch Avenue West. A map of the job area appears in Figure 10 below.

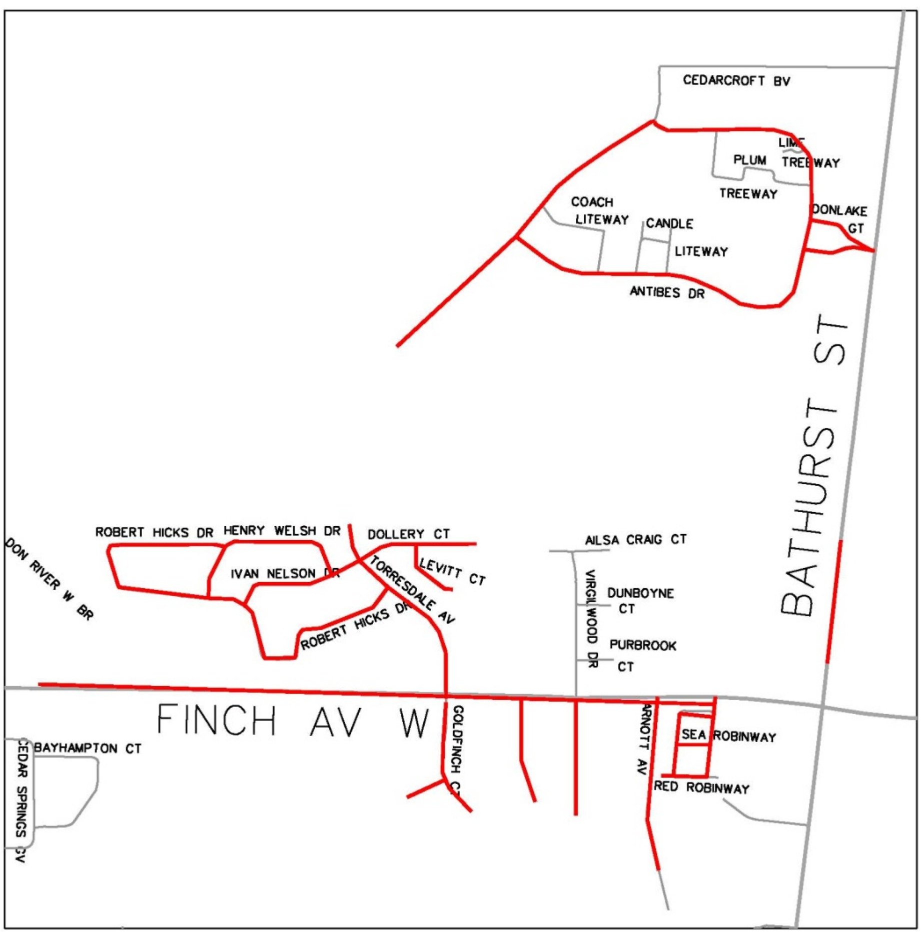


Figure 10: Map of Underground Rehabilitation of Feeder NY80M8

8.5. Required Capital Costs

There are three phases to this job for a total estimated cost of $9.51M.

Table 25: Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21262	W12464 FESI - UG Cable Rehab Antibes 80M2 and 80M8	2014	$1.27
23543	W14229 Finch/Torresdale and Robert Hicks Subdivision Civil	2014	$6.55
23446	W14248 Finch/Torresdale and Robert Hicks Subdivision Electrical	2014	$1.69
		Total:	**$9.51**

9. Underground Rehabilitation of Feeder NY85M6 (W14078, W14096)

9.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY85M6 in order to improve reliability of service.

9.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 8

As is evident from Table 26, this feeder has been experiencing increasingly poor reliability.

Table 26: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY85M6			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	576	1,831	5,833
Feeder CHI ***(Cumulative)***	38	782	12,279

9.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 27: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	7,400 m	Primary Cable	7,400 m
Submersible Transformers	4	Submersible Transformers	4

9.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Bathurst Street to the east, Dufferin Street to the west, Steeles Avenue West to the north, and Sheppard Avenue West to the south. A map of the job area appears in Figure 11 below.

9.5. Required Capital Costs

There are two phases to this job for a total of $2.01M.

1 **Table 28: Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
22865	W14078 UG lateral Cable Rehab Dufferin/Finch/Wilmington	2014	$0.83
22902	W14096 Coreydale/Brockington UG Residential Rebuild	2014	$1.18
		Total:	**$2.01**

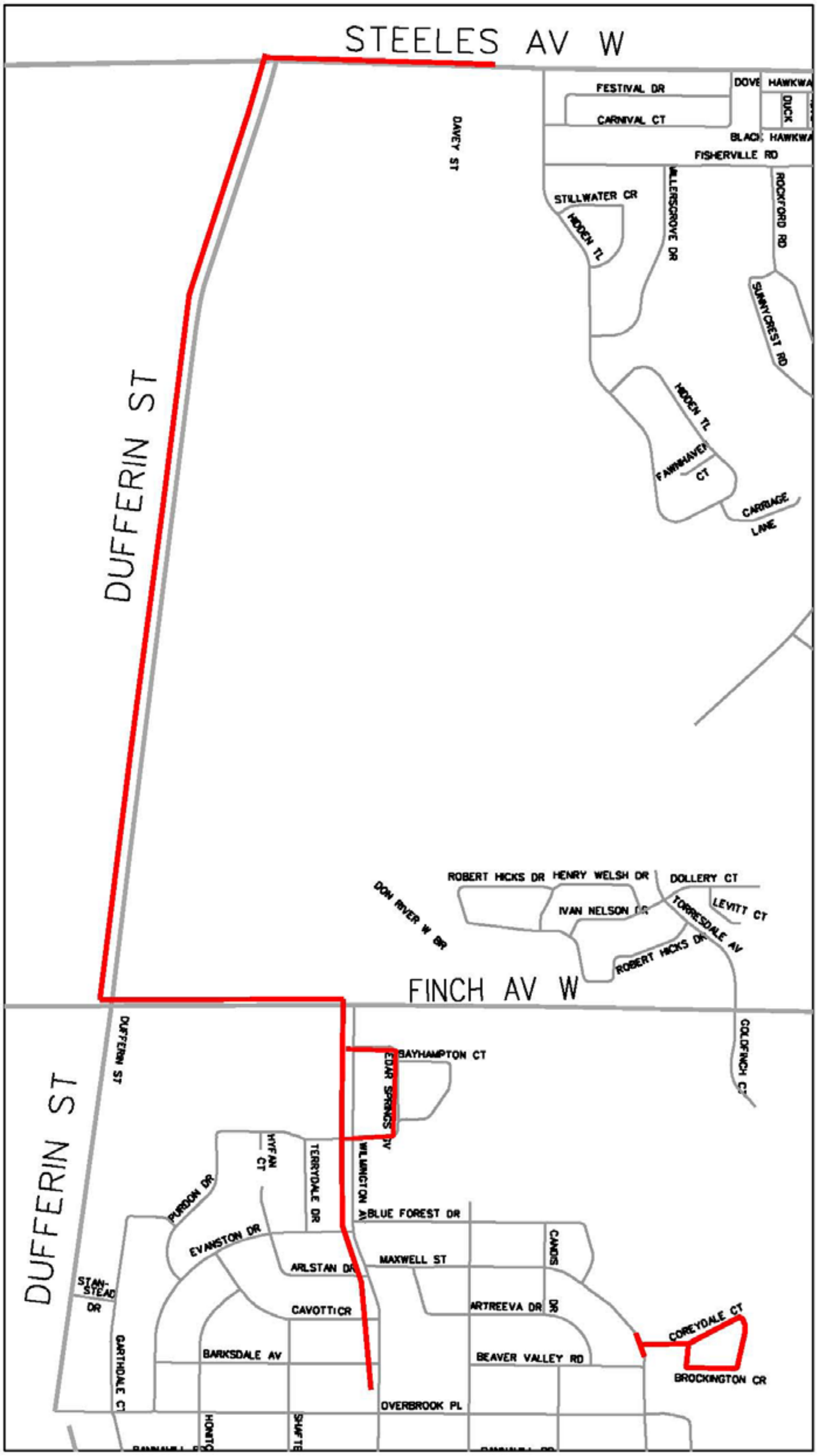


Figure 11: Map of Underground Rehabilitation of Feeder NY85M6

10. Underground Rehabilitation of Feeder NY51M8 (E13078, E13077)

10.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY51M8 in order to improve reliability of service and mitigate potential safety risks.

10.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 8

Table 29 provides reliability data for this feeder. While total CI and CHI for the feeder have been decreasing since 2009, the number of sustained outages due to underground asset failures has been on the rise. Underground asset failures represented the majority of CI in 2009 and 2011.

Table 29: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY51M8			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	6,124	2,277	2,480
Feeder CHI ***(Cumulative)***	2,787	2,634	461

10.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts to replace old direct-buried cable.

Table 30: Asset Replacement

Assets to be Replaced		**New Assets to be Installed**	
Primary Cable	4,000 m	Primary Cable	4,000 m

10.4. Maps and Locations

The assets being replaced by this job are located in the area generally bordered by Leslie Street to the east, Bayview Avenue to the west, Finch Avenue East to the north, and Sheppard Avenue East to the south. A map of the job area appears in Figure 12.

Figure 12: Map of Underground Rehabilitation of Feeder NY51M8

10.5. Required Capital Costs

There are two phases for this job for a total estimated cost of $1.58M.

Table 31: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21298	E13078 UG DB cable replacement between Leslie and Bayview - Civil NY51M8, NY51M6	2013	$1.26
21297	E13077 UG DB cable replacement between Leslie and Bayview - Electrical NY51M8, NY51M6	2014	$0.32
		Total	**$1.58**

11. Underground Rehabilitation of Feeder SCNA502M22 (E11072, E12256, E12259, E13037, E13124, E14009)

11.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNA502M22 to improve reliability of service and mitigate potential safety risks.

11.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 7

As is evident from Table 32, this feeder has been experiencing very poor reliability. This job addresses previous direct buried cable failures that have contributed to the poor reliability of this feeder.

Table 32: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNA502M22			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	19,233	7,957	20,126
Feeder CHI ***(Cumulative)***	11,979	4,185	7,458

11.3. Scope of Work

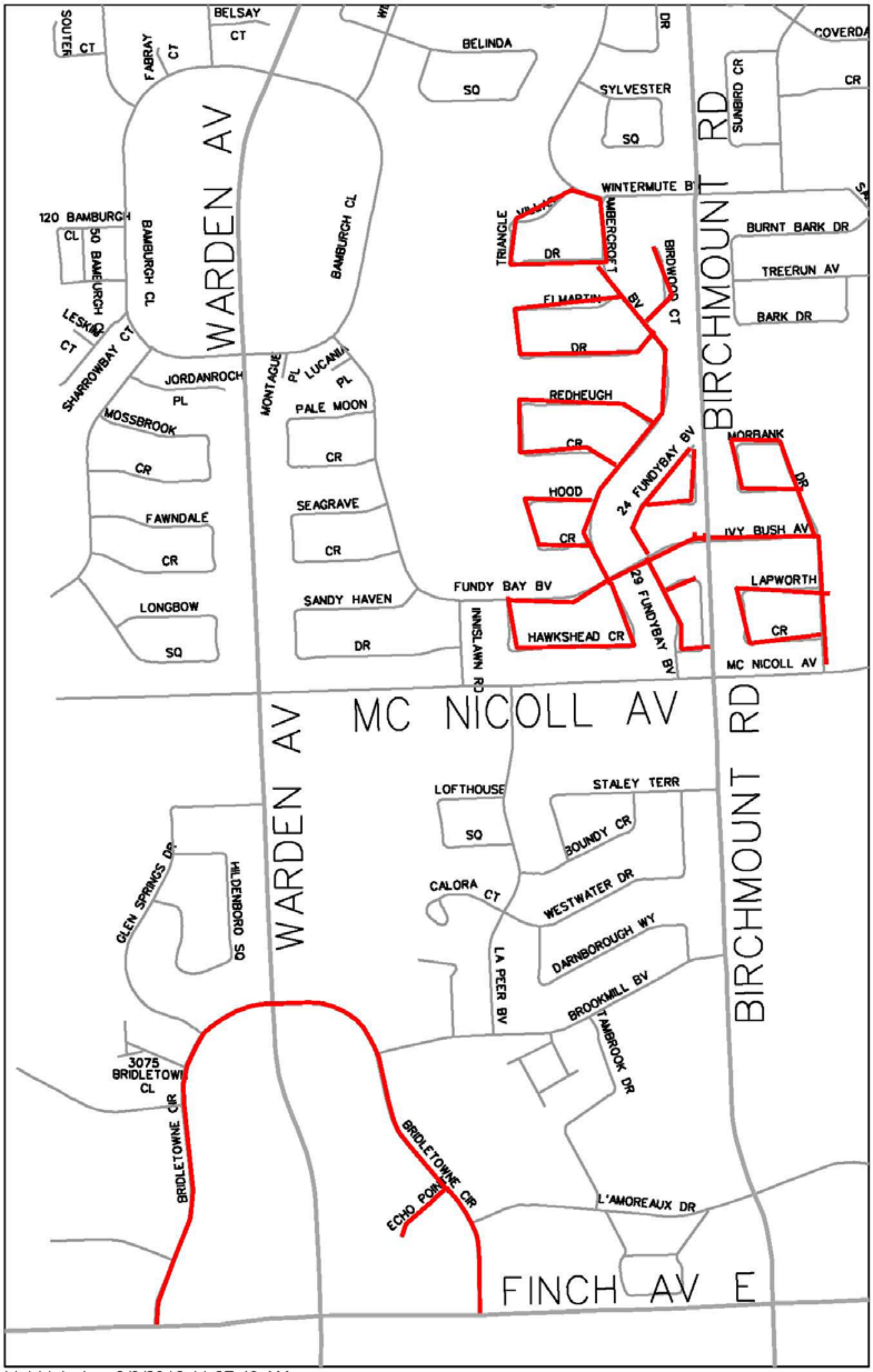
This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 33: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	10,690m	Primary Cable	10,690m
Submersible Transformers	28	Submersible Transformers	28

11.4. Maps and Location

The assets being replaced by this job are located in the area bordered by Kennedy Road to the east, Victoria Park Avenue to the west, Steeles Avenue East to the north, and Finch Avenue East to the south. A map of the job area appears in Figure 13.



1 **Figure 13: Map of Underground Rehabilitation of Feeder SCNA502M22**

11.5. Required Capital Costs

There are seven phases to this job for a total estimated cost of $2.96M.

Table 34: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20948	Bridletowne NA502M22 UG Replacement SCNA502M22 (Elec)	2012	$0.18
20261	E12256 Bridletowne Cable Replacement SCNA502M22 - Electrical	2013	$0.32
20263	E12259 Bridletowne Cable Replacement SCNA502M22 – Civil	2013	$1.03
24683	E13037 2501-61 Bridletowne UG 502M22 Rebuild Electrical SCNA502M22	2012	$0.16
21589	E13124 Rebuild Orange File SD 502M22 UG-Civil	2013	$1.01
21591	E14009 Rebuild Orange File SD 502M22 UG-Electrical	2014	$0.25
		Total:	**$2.96**

12. Underground Rehabilitation of Feeder SCNAH9M30 (E12188, E12348, E13011, E14190, E14191)

12.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNAH9M30 to improve reliability of service and mitigate potential safety risks.

12.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 7

Table 35 provides historical reliability data for this feeder. In 2009, there were multiple major underground primary cable failures on this feeder. These failures were responsible for 97% of CI and 85% of CHI for that year. Although fewer cable failures took place over the next two years and, as a result, the overall CI and CHI data showed an improving trend, the previous direct buried cable failures on this feeder indicate that it still needs to be replaced through this job.

Table 35: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNAH9M30			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	8,147	6,796	2,461
Feeder CHI ***(Cumulative)***	8,175	9,441	3,239

12.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 36: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	4,450m	Primary Cable	4,450m
Submersible Transformers	25	Submersible Transformers	25
Air-insulated Vault-installed Switchgear	1	SF_6-insulated Vault-installed Switchgear	1

12.4. Maps and Locations

The assets being replaced by this job are located in the vicinity of the intersection of Markham Road and Eglinton Avenue East. A map of the job area appears in Figure 14.

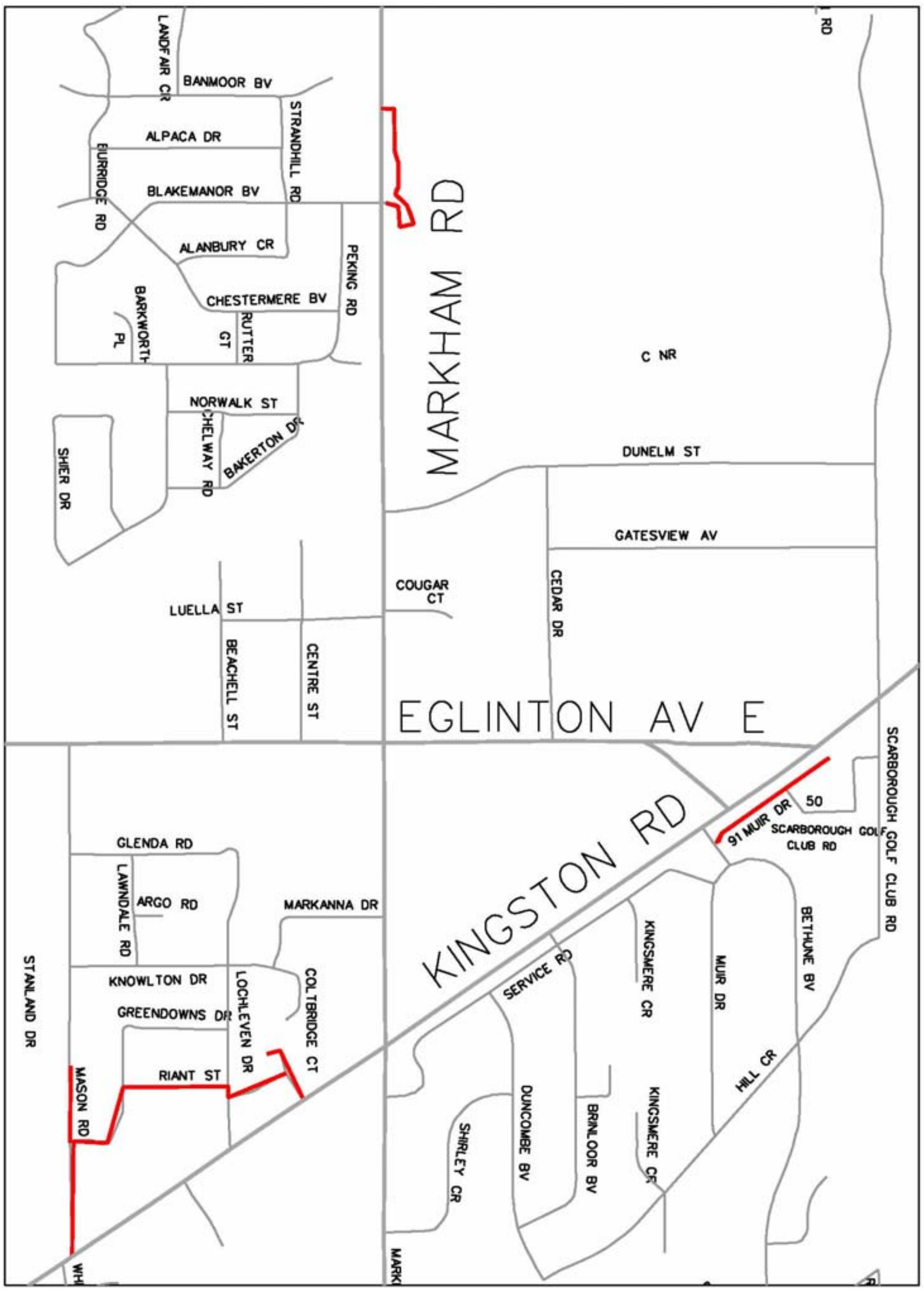


Figure 14: Map of Underground Rehabilitation of Feeder SCNAH9M30

12.5. Required Capital Costs

There are five phases to this job for a total estimated cost of $3.56M.

Table 37: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20001	E12188 H9M30 435 Markam Rd TH UG Rehab	2013	$0.33
20520	E12348 H9M30 UG Rebuild Muir Dr - Golf Club - Civil SCNAH9M30	2013	$0.48
20525	E13011 H9M30 UG Rebuild Muir Dr - Golf Club - Electrical SCNAH9M30	2014	$0.36
23297	E14190 UG Rebuild H9M30 Kingston Mason - Civil	2014	$1.72
23300	E14191 UG Rebuild H9M30 Kingston Mason - Electrical	2014	$0.67
		Total:	**$3.56**

13. Underground Rehabilitation of Feeder NY85M4 (W13239, W13278, W14153, W14154, W14155)

13.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY85M4 in order to improve reliability of service and mitigate potential safety risks.

13.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 7

Table 38 presents historical reliability data for this feeder. While there is a drop in CI and CHI in 2010, the overall trend is worsening reliability.

Table 38: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY85M4			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	524	26	2,862
Feeder CHI ***(Cumulative)***	129	84	6,235

This job addresses direct buried cable failures that have occurred on this feeder.

13.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 39: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	14,500 m	Primary Cable	14,500 m
Submersible Transformers	30	Submersible Transformers	30
Air-insulated Vault-installed Switchgear	3	SF_6-insulated Vault-installed Switchgear	3

13.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Dufferin Street to the east, Sentinel Road to the west, Finch Avenue West to the north, and Sheppard Avenue West to the south. A map of the job area appears in Figure 15.

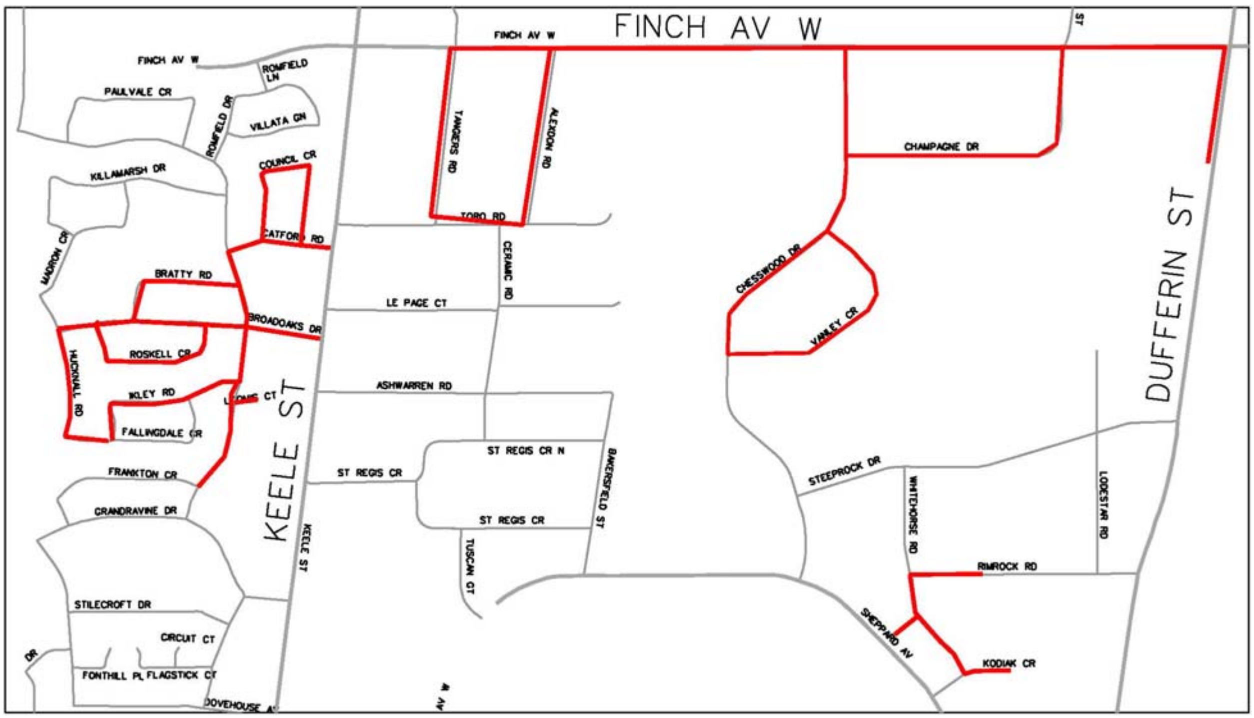


Figure 15: Map of Underground Rehabilitation of Feeder NY85M4

13.5. Required Capital Costs

There are five phases to this job for a total estimated cost of $8.27M.

Table 40: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
22716	W13239 Northview Heights Electrical Rebuild	2013	$2.48
22715	W13278 Northview Heights Civil Rebuild	2013	$2.48
23258	W14153 UG Rebuild and Cable Replacement Whitehorse/Kodiak	2014	$0.51
23313	W14154 Lateral Cable Replacement Dufferin/Finch/Toro	2014	$1.30
23330	W14155 Lateral Cable Replacement Chesswood/Champagne	2014	$1.50
		Total:	**$8.27**

14. Underground Rehabilitation of Feeder SCNA47M13 (E12209, E12228, E12275, E12276, E13014 and E13015)

14.1. Objectives

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNA47M13 in order to improve reliability of service and mitigate potential safety risks.

14.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

As is clear from Table 41, this feeder has been experiencing increasingly worsening reliability. This is partially due to failures of underground assets, including direct buried cable.

Table 41: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNA47M13			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	4,889	10,328	17,600
Feeder CHI ***(Cumulative)***	2,653	11,821	12,499

14.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 42: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	11,600 m	Primary Cable	11,600 m
Submersible Transformers	63	Submersible Transformers	63

14.4. Maps and Locations

The assets being replaced by this job are located in the vicinity of the intersection of Meadowvale Road and Ellesmere Road. A map of the job area appears in Figure 16.

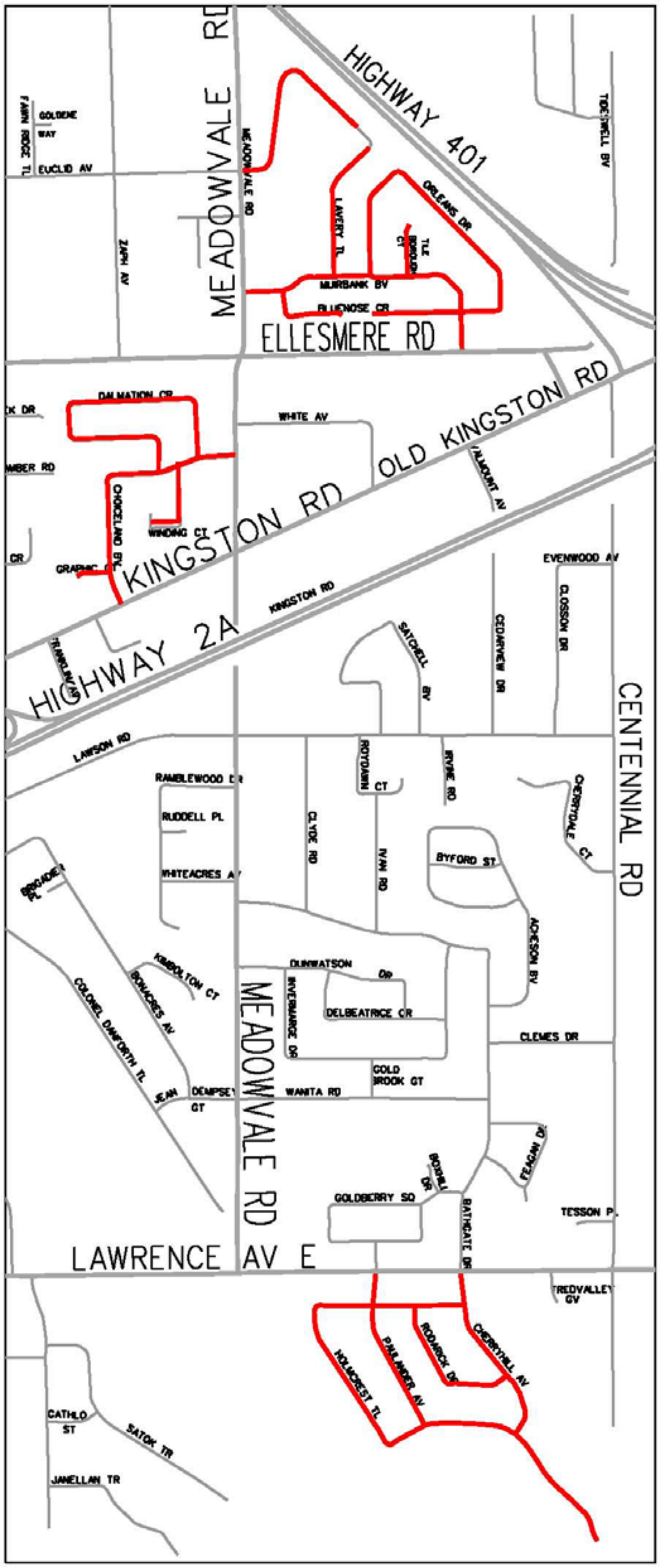
14.5. Required Capital Costs

There are six phases to this job for a total of $4.91M.

Table 43: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
24843	E12275 Muirbank 47M13 UG Rebuild - Civil	2013	$0.98
20637	E13014 Holmcrest 47M13 UG Rebuild - Civil	2013	$1.41
20066	E12209 Dalmatian/Choiceland 47M13 UG Rebuild-Civil	2013	$1.20
20067	E12228 Dalmatian/Choiceland 47M13 Rebuild - Electrical	2014	$0.36
24636, 24844	E12276 Muirbank 47M13 UG Rebuild - Electrical	2014	$0.52
20638	E13015 Holmcrest 47M13 UG Rebuild - Electrical	2014	$0.44
		Total:	**$4.91**

ICM Project | Underground Infrastructure Segment



1 **Figure 16: Map of Underground Rehabilitation of Feeder SCNA47M13**

15. Underground Rehabilitation of Feeder NY80M2 (W12449, W12451)

15.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY80M2 in order to improve reliability of service and mitigate potential safety risks.

15.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

Table 44 provides historical reliability data for this feeder. Overall, this feeder has been exhibiting a worsening reliability trend. The spike in CI and CHI in 2010 is due to asset failures. In 2010, 4,191 of CHI were due to underground asset failures. Over the past two years, 63% of asset related sustained outages have been due to underground asset failures.

Table 44: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY80M2			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	2,050	7,966	2,809
Feeder CHI ***(Cumulative)***	395	5,441	1,354

15.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts to replace old direct-buried cable.

Table 45: Asset Replacement

Assets to be Replaced		**New Assets to be Installed**	
Primary Cable	5,100 m	Primary Cable	5,100 m

15.4. Maps and Locations

The assets being replaced by this job are located in the vicinity of Bathurst Street, south of Steeles Avenue West. A map of the job area appears in Figure 17.

15.5. Required Capital Costs

There are two phases to this job for a total estimated cost of $1.63M in 2013.

Table 46: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20902	W12449 FESI - Lateral Cable and Tx Rehab Bathurst and Rockford	2013	$0.89
20895	W12451 FESI - UG Lat cable and transformer Rehab Cedarcroft, Patricia	2013	$0.74
		Total:	**$1.63**

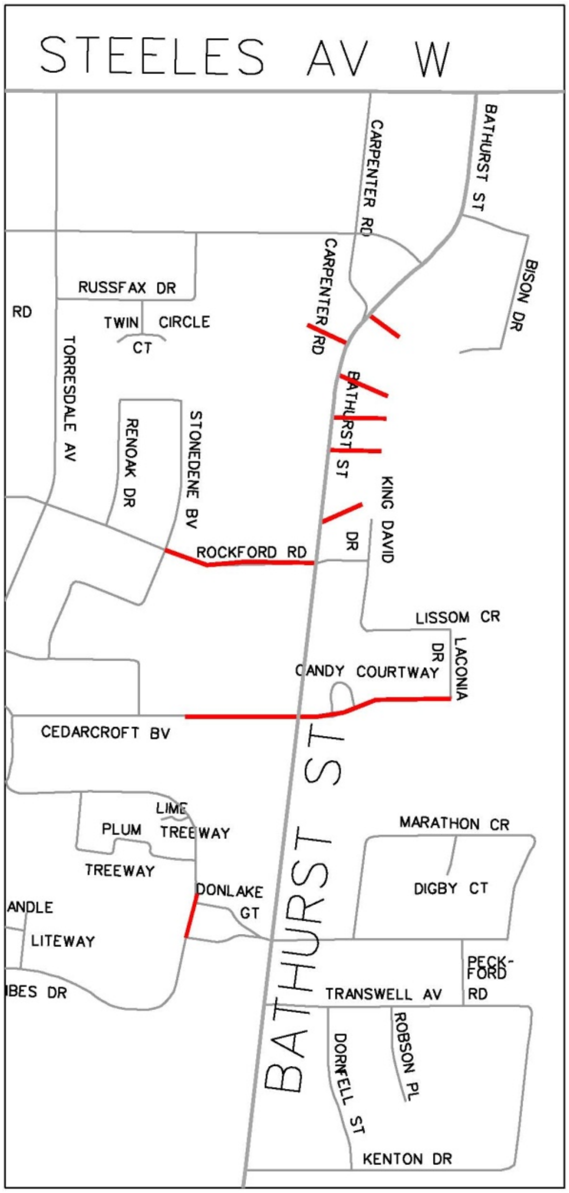


Figure 17: Map of Underground Rehabilitation of Feeder NY80M2

16. Underground Rehabilitation of Feeder NY51M7 (E13074, E13075)

16.1. Objective

The objective of this job is to proactively replace underground assets on 27.6kV feeder NY51M7 in order to improve reliability of service and mitigate potential safety risks.

16.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

Historical reliability data for this feeder is presented in Table 47. This significant rise in CI and CHI in 2010 is due to an increase in overhead and underground asset failures. Nearly half of the CI in 2010 is due to primary cable failure. This job aims to address the increase in primary cable failures in 2010.

Table 47: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY51M7			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	5,466	9,764	3,126
Feeder CHI ***(Cumulative)***	1,783	3,676	1,728

16.3. Scope of Work

This job replaces both civil and electrical assets in 2013. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 48: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	4,000 m	Primary Cable	4,000 m
Submersible transformer	1	Submersible transformer	1

16.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Leslie Street to the east, Bayview Avenue to the west, Hawsbury Drive to the north, and York Mills Road to the south. A map of the job area appears in Figure 18.

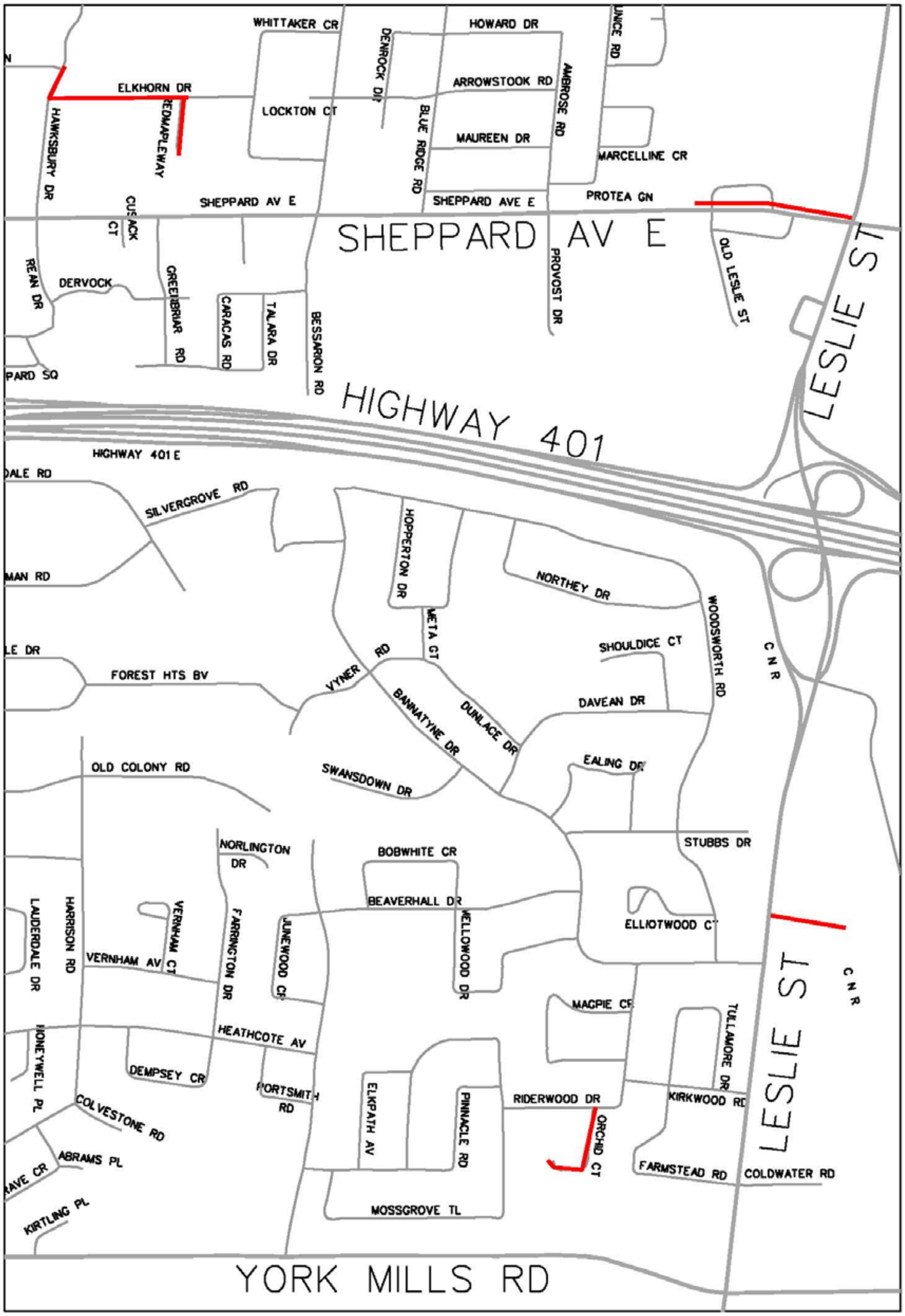


Figure 18: Map of Underground Rehabilitation of Feeder NY51M7

16.5. Required Capital Costs

There are two phases to this job for a total estimated cost of $1.40M in 2013.

Table 49: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21290	NY51M7 Replacement of DB Cables btn Leslie & Bayview - Electrical	2013	$0.27
21291	NY51M7 Replacement of DB Cables btn Leslie & Bayview - Civil	2013	$1.13
		Total	**$1.40**

17. Underground Rehabilitation of Feeder NY51M24 (E13102, E13103, E13107, E13108, E13099, E13098, E13101, E13104, E13106, E13058, E13069)

17.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY51M24 in order to improve reliability of service and mitigate potential safety risks.

17.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

This feeder has been regularly experiencing underground asset failures over the past ten years. These failures have been contributing significantly to the number of unplanned sustained outages, as well as CI and CHI. This job provides a long-term solution to address previous direct buried cable failures on this feeder and reduce the likelihood of future underground asset failures.

Table 50 provides historical reliability data for this feeder.

Table 50: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY51M24			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	4,337	6,265	270
Feeder CHI ***(Cumulative)***	3,518	5,410	942

17.3. Scope of Work

This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 51: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	20,040 m	Primary Cable	20,040 m
Submersible Transformers	22	Submersible Transformers	22
Air-insulated Vault-installed Switchgear	6	SF_6-insulated Vault-installed Switchgear	6

17.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Highway 404 to the east, Leslie Street to the west, Finch Avenue East to the north, and Highway 401 to the south. Maps of the job areas appear in Figure 19 and Figure 20.

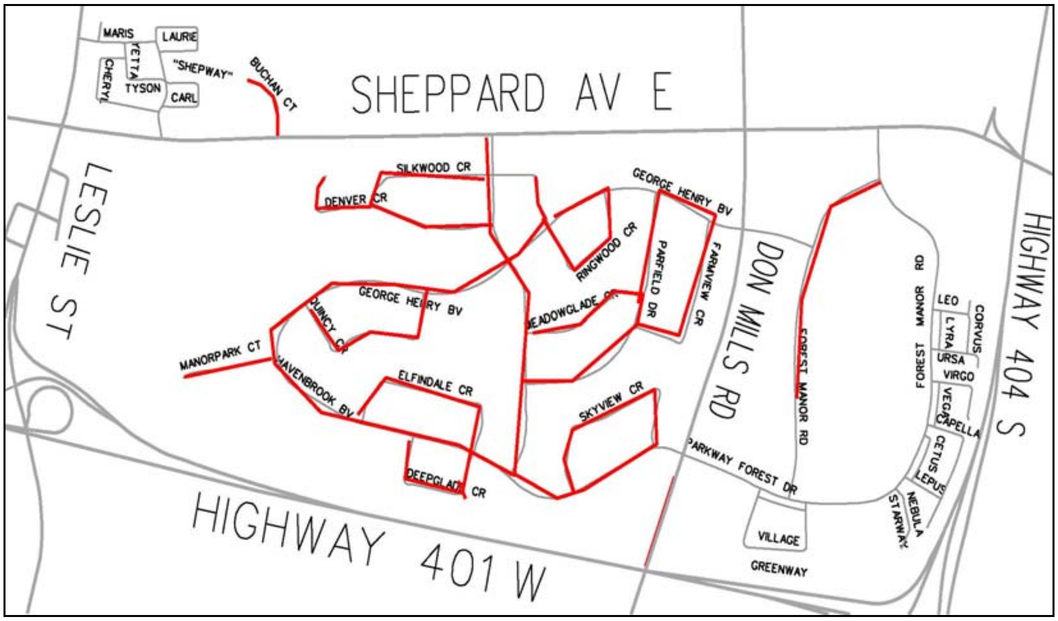


Figure 19: Map of Underground Rehabilitation of Feeder NY51M24

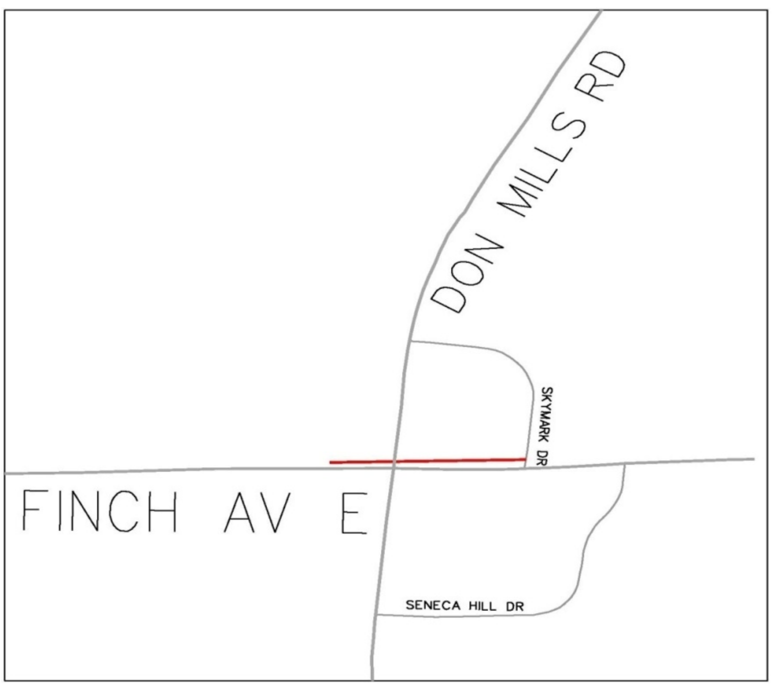


Figure 20: Map of Underground Rehabilitation of Feeder NY51M24

17.5. Required Capital Costs

There are 11 phases to this job for a total estimated cost of $5.64M.

1 **Table 52: Required Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21449	E13102 UG rebuild of NY51M24 Forest Manor Rd East of Don Mills - Electrical NY51M24	2013	$0.08
21446	E13108 UG rebuild of NY51M24 Buchan Crt by Sheppard Ave E. - Electrical NY51M24	2013	$0.25
21450	E13102 UG rebuild of NY51M24 Forest Manor Rd East of Don Mills - Civil NY51M24	2013	$0.23
21447	E13108 UG rebuild of NY51M24 Buchan Crt by Sheppard Ave E. - Civil NY51M24	2013	$0.24
21500	E13099 UG Rebuild on Don Mills between Sheppard and Graydon - Electrical NY51M24	2013	$0.19
21401	E13098 NY51M24 UG Rebuild in Subdivision by Don Mills & Sheppard Part 1 - Electrical NY51M24	2013	$0.86
21410	E13101 NY51M24 UG Rebuild in Subdivision by Don Mills & Sheppard Part 2 - Electrical NY51M24	2013	$0.64
21433	E13104 NY51M24 UG Rebuild in Subdivision by Don Mills & Sheppard Part 1 - Civill NY51M24	2013	$1.12
21434	E13106 NY51M24 UG Rebuild in Subdivision by Don Mills & Sheppard Part 2 - Civill NY51M24	2013	$1.35
21110	E13058 NY51M24, NY51M25 UG Rebuild Finch & Don Mills - Electrical NY51M24, NY51M25	2014	$0.16
21202	E13069 NY51M24, NY51M25 UG Rebuild Finch & Don Mills - Civil NY51M24, NY51M25	2014	$0.51
		Total	**$5.64**

2

18. Underground Rehabilitation of Feeder NY80M30 (W11455, W11456, W11460, W12077)

18.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY80M30 in order to improve reliability of service and mitigate potential safety risks.

18.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

Table 53 presents historical reliability data for this feeder. The majority of CI and CHI in 2010, specifically 7,188 out of 9,370 in CI and 2,992 out of 4,962 in CHI, was due to underground asset failures. This job rehabilitates the feeder to address direct buried cable that has failed in the recent past and to reduce the likelihood of failures of other underground assets.

Table 53: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY80M30			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	7,419	9,370	442
Feeder CHI ***(Cumulative)***	5,809	4,962	256

18.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 54: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	40,300 m	Primary Cable	40,300 m
Submersible Transformers	30	Pad-mounted Transformers	30
Air-insulated Pad-mounted Switchgear	1	SF_6-insulated Pad-mounted Switchgear	1
Air-insulated Vault-installed Switchgear	1	SF_6-insulated Vault-installed Switchgear	1

18.4. Maps and Location

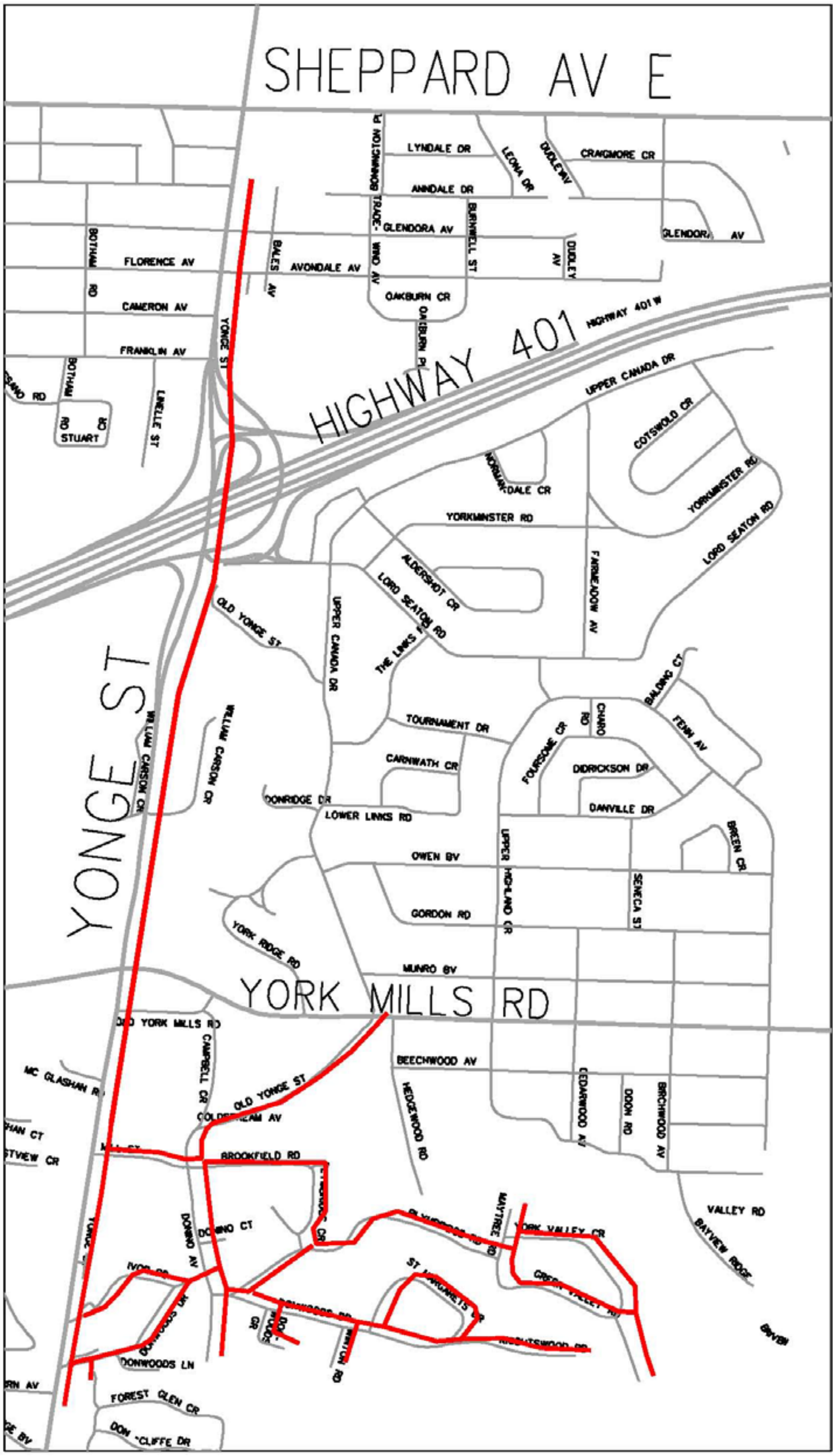
The assets being replaced by this job are located along Yonge Street between Lawrence Avenue and Sheppard Avenue. A map of the job area appears in Figure 21.

18.5. Required Capital Costs

There are four phases to this job for a total estimated cost of $8.95M in 2012.

Table 55: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
18845	W11455 FESI-12 Yonge St UG Fdr Cable rehab (NY80M30/M27)	2012	$0.39
19032	W11456 FESI-12 Hwy 401 UG Fdr Cable rehab NY80M30	2012	$1.56
19399	W11460 FESI-12 NY80M30 Johnston/Yonge UG Fdr Cable rehab	2012	$0.02
19522	W12077 Hoggs Hollow UG Rebuild (NY80M30)	2012	$6.97
		Total:	**$8.95**



1 **Figure 21: Map of Underground Rehabilitation of Feeder NY80M30**

19. Underground Rehabilitation of Feeder NY55M23 (W14284, W14350)

19.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY55M23 to improve reliability of service and mitigate potential safety risks.

19.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

Table 56 presents reliability data for this feeder for 2009, 2010 and 2011. The high CI and CHI in 2010 as compared with 2009 and 2011 is primarily due to primary cable failures.

Table 56: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY55M23			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	115	6,533	3,170
Feeder CHI ***(Cumulative)***	455	1,367	915

19.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 27.6 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 57: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	1,575 m	Primary Cable	1,575 m
Submersible Transformers	3	Submersible Transformers	3

19.4. Maps and Locations

The assets being replaced by this job are located in the Highway 401 and Jane Street area. A map of the job area appears in Figure 22.

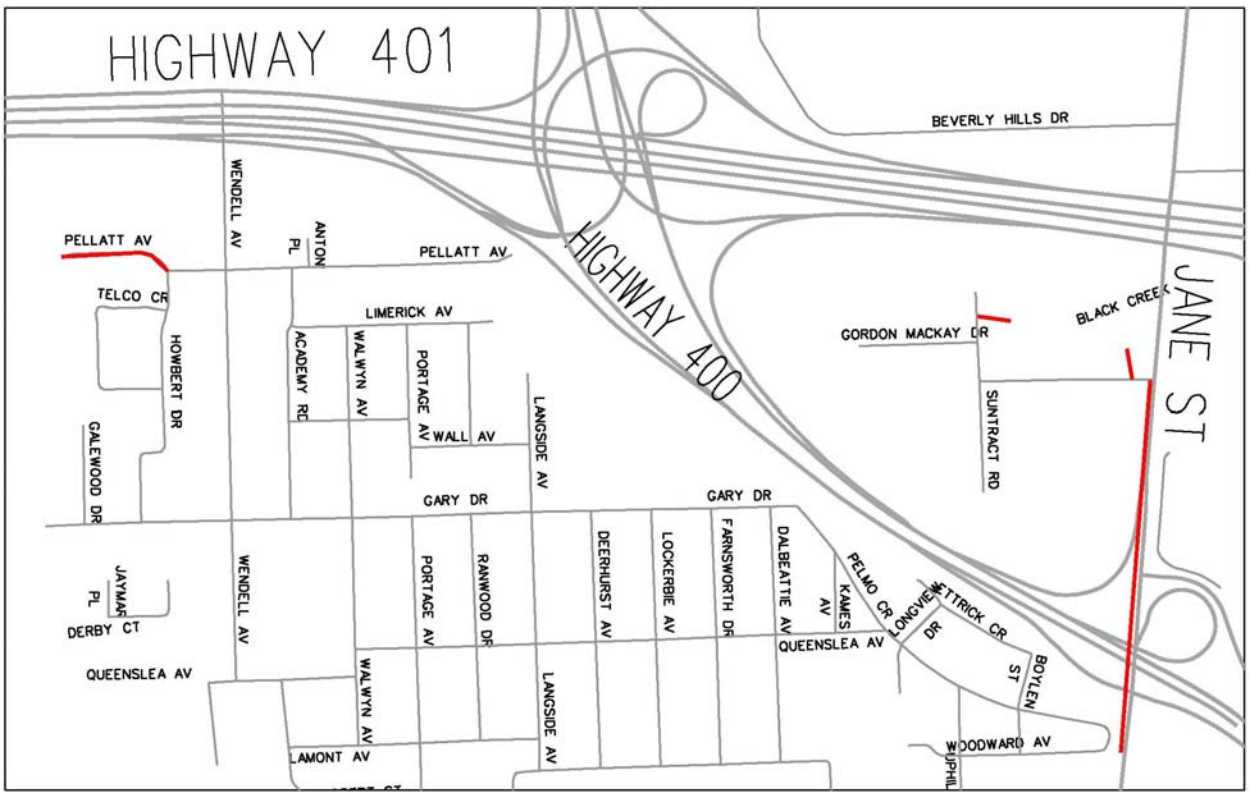


Figure 22: Map of Underground Rehabilitation of Feeder NY55M23

19.5. Required Capital Costs

There are two phases to this job for a total estimated cost of $2.24M in 2014.

Table 58: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
23947	W14284 Pellatt Ave. UG DB Rebuild NY55M23	2014	$1.07
24386	W14350 P01 Gordon Mackay Underground Rebuild	2014	$1.17
		Total:	**$2.24**

20. Underground Rehabilitation of Feeder NY85M24 (W14268, W14269, W14270)

20.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY85M24 in order to improve reliability of service and mitigate potential safety risks.

20.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

Historical reliability data for this feeder is presented in Table 59. As can be seen, there is an overall trend of worsening reliability.

Table 59: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY85M24			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	2,726	62	4,793
Feeder CHI ***(Cumulative)***	1,322	52	3,024

This job rebuilds areas that have experienced direct buried cable failures.

20.3. Scope of Work

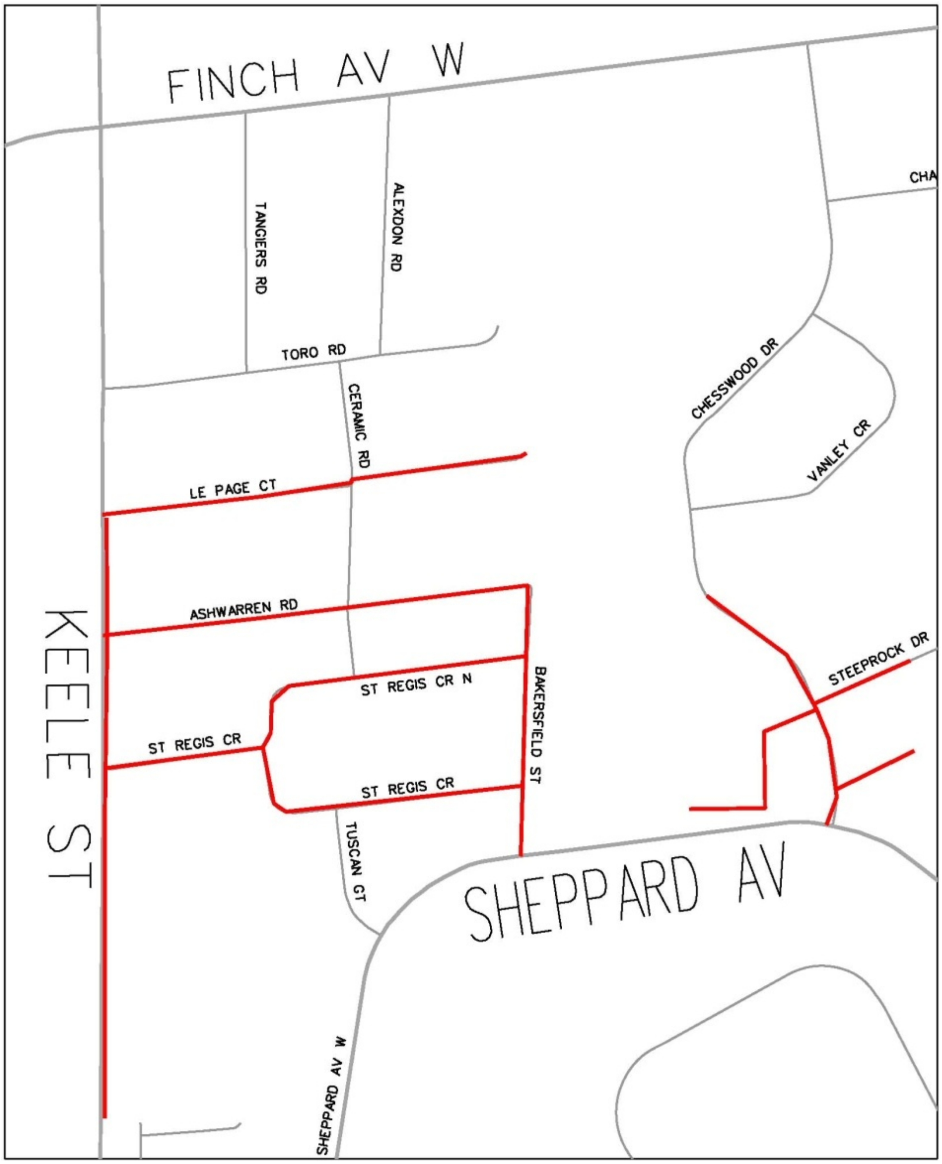
This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new SF_6-insulated switchgear. Assets to be replaced include direct-buried cable and air-insulated switchgear.

Table 60: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	14,100 m	Primary Cable	14,100 m
Air-insulated Vault-installed Switchgear	1	SF_6-insulated Vault-installed Switchgear	1

20.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Dufferin Street to the east, Keele Street to the west, Finch Avenue West to the north, and Sheppard Avenue West to the south. A map of the job area appears in Figure 23.



1 **Figure 23: Map of Underground Rehabilitation of Feeder NY85M24**

20.5. Required Capital Costs

There are three phases to this job for a total of $2.03M.

Table 61: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
23818	Chesswood and Steeprock Dr. Lateral Replacement NY85M24	2014	$0.56
23819	St. Regis, Bakersfield & Ashwarren Lateral Replacement NY85M24	2014	$0.86
23820	Lepage and Keele St. Lateral Replacement	2014	$0.61
		Total:	**$2.03**

21. Underground Rehabilitation of Feeder SCNAE5-2M3 (E12202, E12230)

21.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNAE5-2M3 to improve reliability of service and mitigate potential safety risks.

21.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

This feeder has exhibited worsening reliability, as is evident from Table 62. Moreover, failures of underground assets have represented the majority of asset related sustained outages on this feeder. This job rebuilds an area that experienced a direct buried cable failure in 2010.

Table 62: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNAE5-2M3			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	174	297	2,374
Feeder CHI ***(Cumulative)***	448	1,376	758

21.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, replacing old direct-buried cable.

Table 63: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	6,000m	Primary Cable	6,000m

21.4. Maps and Locations

The assets being replaced by this job are located in the vicinity of the intersection of Kingston Road and McCowan Road. A map of the job area appears in Figure 24.

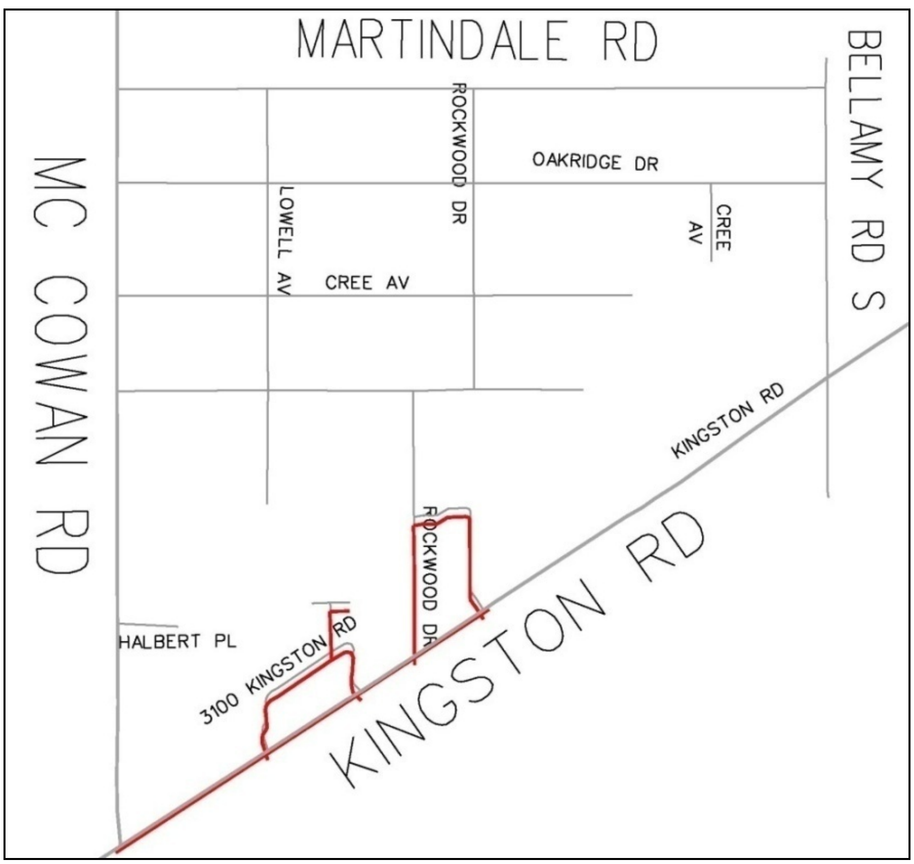


Figure 24: Map of Underground Rehabilitation of Feeder SCNAE5-2M3

21.5. Required Capital Costs

There are two phases to this job for a total of $1.51M.

Table 64: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20106	E12202 Rehab of Feeder NAE5-2M3 in McCowan and Kingston area (Electrical)	2013	$0.42
20136	E12230 Rehab of Feeder NAE5-2M3 in McCowan and Kingston area (Civil)	2013	$1.09
		Total:	**$1.51**

22. Underground Rehabilitation of Feeder NY85M7 (W14129, W14130, W14131, W14132, W14133, W14134, W14135)

22.1. Objectives

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY85M7 in order to improve reliability of service and mitigate potential safety risks.

22.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 6

Table 65 provides historical reliability data for this feeder. Over the past ten years, underground asset failures have represented the 82% of asset failures and have contributed significantly to CI and CHI.

Table 65: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY85M7			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	1,228	3,414	85
Feeder CHI ***(Cumulative)***	1,415	773	36

This job rebuilds areas that have experienced direct buried cable failures.

22.3. Scope Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cables and submersible transformers.

Table 66: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	8,580 m	Primary Cable	8,580 m
Submersible Transformers	41	Submersible Transformers	41

22.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Bathurst Street to the east, Keele Street to the west, Steeles Avenue West to the north, and Finch Avenue West to the south. A map of the job area appears in Figure 25.

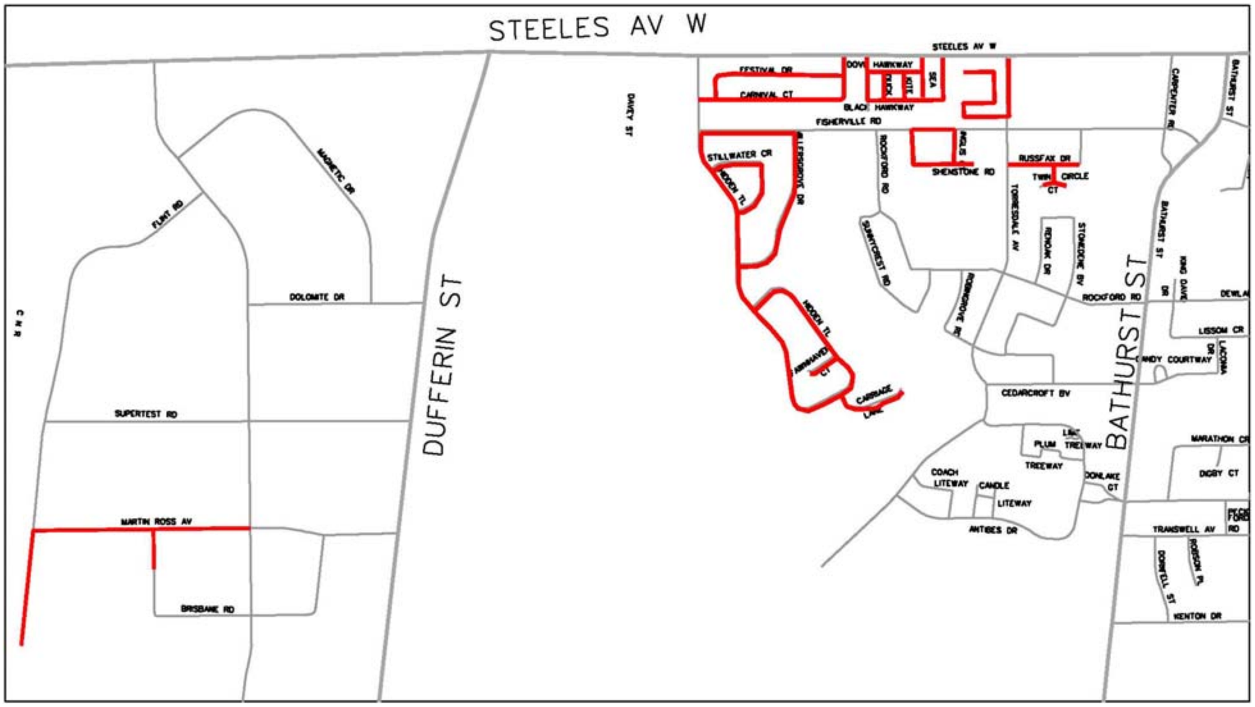


Figure 25: Map of Underground Rehabilitation of Feeder NY85M7

22.5. Required Capital Costs

There are eight phases to this job for a total of $13.83M.

Table 67: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
23006	W14129 Torresdale UG DB Rebuild	2014	$0.64
23009	W14130 Rebuild Russfax and Twin Circle Crt	2014	$0.46
22992	W14131 UG DB Rebuild Ingles Gate & Shenstone Rd	2014	$0.77
23004	W14132 Black Hawkway DB Rebuild	2014	$2.05
23043	W14133 UG DB Rebuild on Festival and Carnival	2014	$2.55
22984	W14134 UG DB PH#1 Rebuild Hidden Trail and Surrounding Area	2014	$3.75
22987	W14135 UG DB PH#2 Rebuild Hidden Trail and Surrounding Area	2014	$3.61
		Total:	**$13.83**

23. Underground Rehabilitation of Feeder SCNT63M12 (E11472, E11483, E11484, E11618, E12081, E12094, E12095, E12096, E12317, E13152, E14011)

23.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNT63M12 to improve reliability of service and mitigate potential safety risks.

23.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 5

This feeder has been experiencing very poor reliability. Table 70 presents reliability data for 2009, 2010, and 2011. 78% of sustained outages during this period were related to underground asset failures.

Table 68: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNT63M12			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	4,968	1,459	18,772
Feeder CHI ***(Cumulative)***	6,925	5,414	31,571

This job rebuilds areas that have experienced direct buried cable failures.

23.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 69: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	64,529m	Primary Cable in	64,529m
Submersible Transformers	121	Submersible Transformers	121
Air-insulated Pad-mounted Switchgear	13	SF_6-insulated Pad-mounted Switchgear	13
Air-insulated Vault-installed Switchgear	10	SF_6-insulated Vault-installed Switchgear	10

23.4. Maps and Locations

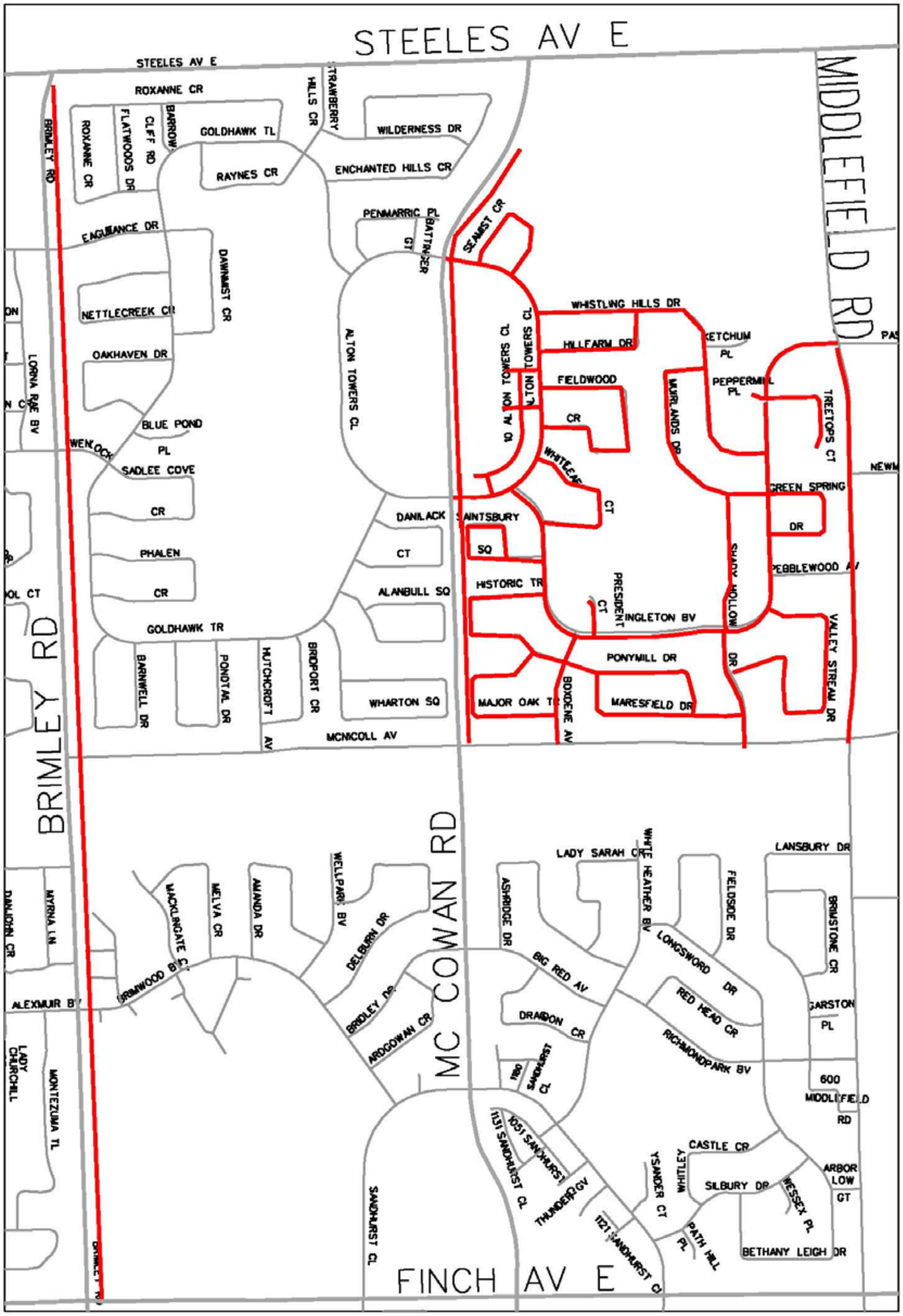
The assets being replaced by this job are located in the area bordered by Middlefield Road to the east, Brimley Road to the west, Steeles Avenue East to the north, and Finch Avenue East to the south. A map of the job area appears in Figure 26.

23.5. Required Capital Costs

There are 11 phases to this job for a total of $11.14M.

Table 70: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
22215	E11618 Rebuild Ingleton UG SCNT63M12 Main (Civil) - Ph B	2012	$0.06
20438	E11472 Rebuild Ingleton UG SCNT63M12 Main (Civil) - Ph A	2012	$0.06
19001	E11483 Rebuild Ingleton 63M12 - Ph 1 - Civil	2012	$3.45
19005	E11484 Rebuild Ingleton SCNT63M12 Ph 2 (Civil)	2012	$0.04
19437	E12081 Rebuild Ingleton Main Ph A - Elect	2012	$1.26
19448	E12095 Rebuild Ingleton Ph 2 Elect	2012	$0.67
24717	E12317 Rebuild Ingleton Main Ph B - Elect	2012	$0.56
19442	E12094 Rebuild Ingleton Ph 1 Elect	2013	$1.22
24658	E12096 Rebuild Ingleton Ph 3 Elect	2013	$1.20
21868	E13152 Rebuild UG Trunk NT63M12 M8 Brimley -Civil	2014	$1.69
21869	E14011 Rebuild UG Trunk NT63M12 M8 Brimley - Electrical	2014	$0.93
		Total:	**$11.14**



1 **Figure 26: Map of Underground Rehabilitation of Feeder SCNT63M12**

24. Underground Rehabilitation of Feeder SCNT63M8 (E12493, E12494, E12495, E13042, E13043, E13044, E13129, E13267, E14010, E14047)

24.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNT63M8 to improve reliability of service and mitigate potential safety risks.

24.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 5

Reliability information pertaining to this feeder indicates that historically the majority of asset related sustained outages on this feeder are due to the failure of underground assets. These failures have contributed significantly to CI and CHI.

In 2009, 28.2% of CI and 2.8% of CHI were due to air-insulated switchgear failures. These figures jumped to 99.7% in 2011.

Table 71 provides historical reliability data for this feeder. This feeder has both overhead and underground assets. Overhead asset failures did not cause sustained outages in 2010 and 2011, but overhead asset failures did account for most of CI and CHI in 2009. Without the impact of overhead asset failures in Table 71, the table would show a worsening reliability trend for this feeder from 2009 to 2011. In other words, it is the underground asset failures that are causing worsening reliability for this feeder.

Table 71: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNT63M8			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	11,495	227	5,313
Feeder CHI ***(Cumulative)***	5,276	658	5,879

24.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 72: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	24,002m	Primary Cable	24,002m
Submersible Transformers	58	Submersible Transformers	58
Air-insulated Pad-mounted Switchgear	6	SF_6-insulated Pad-mounted Switchgear	6

24.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Markham Road to the east, Kennedy Road to the west, McNicoll Avenue to the north, and Finch Avenue East to the south. A map of the job area appears in Figure 27.

Figure 27: Map of Underground Rehabilitation of Feeder SCNT63M8

24.5. Required Capital Costs

There are 12 phases to this job for a total of $7.59M.

Table 73: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20973	E12493 FESI UG Rebuild NT63M8 Revlis Sub Part 1- Civil SCNT63M8	2013	$0.62
20978	E12494 FESI UG Rebuild NT63M8 Revlis Sub Part 2-Civil SCNT63M8	2013	$1.87
20979	E12495 FESI UG Rebuild NT63M8 Revlis Sub Part 3-Civil SCNT63M8	2013	$1.77
21864	E13129 Rebuild UG Trunk NT63M8 M11 McCowan-Civil	2013	$0.65
22591	E13267 UG Rebuild 63M8 Silver star Midland- Civil	2013	$0.43
21356	E13042 FESI UG Rebuild NT63M8 Revlis Sub Part 1- Elec SCNT63M8	2014	$0.53
21357	E13043 FESI UG Rebuild NT63M8 Revlis Sub Part 2-Elec SCNT63M8	2014	$0.41
21358	E13044 FESI UG Rebuild NT63M8 Revlis Sub Part 3-Elec SCNT63M8	2014	$0.67
21865	E14010 Rebuild UG Trunk NT63M8 M11 McCowan-Electrical	2014	$0.34
22592	E14047 UG Rebuild 63M8 Silver star Midland- Electrical	2014	$0.30
		Total:	**$7.59**

25. Underground Rehabilitation of Feeder SCNAE5-1M29 (E11421)

25.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNAE5-1M29 to improve reliability of service and mitigate potential safety risks.

25.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 5

The majority of asset-related sustained outages on this feeder are due to the failure of underground assets. Over the past three years, the number of sustained outages due to primary underground cables increased significantly. In 2009, underground primary cable failures only accounted for 17% of overall outage. In 2011, this percentage spiked to 80%. In 2011, underground primary cable failures accounted for 94% of CHI. Table 74 presents historical reliability data for this feeder.

Table 74: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNAE5-1M29			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	1,934	8,032	2,676
Feeder CHI ***(Cumulative)***	3,827	4,101	1,952

This job rebuilds an area that has experienced multiple direct buried cable failures.

25.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 75: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	19,600m	Primary Cable	19,600m
Submersible Transformers	30	Submersible Transformers	30

25.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Kennedy Road to the east, Birchmount Road to the west, Highway 401 to the north, and Ellesmere Road to the south. A map of the job area appears in Figure 28.

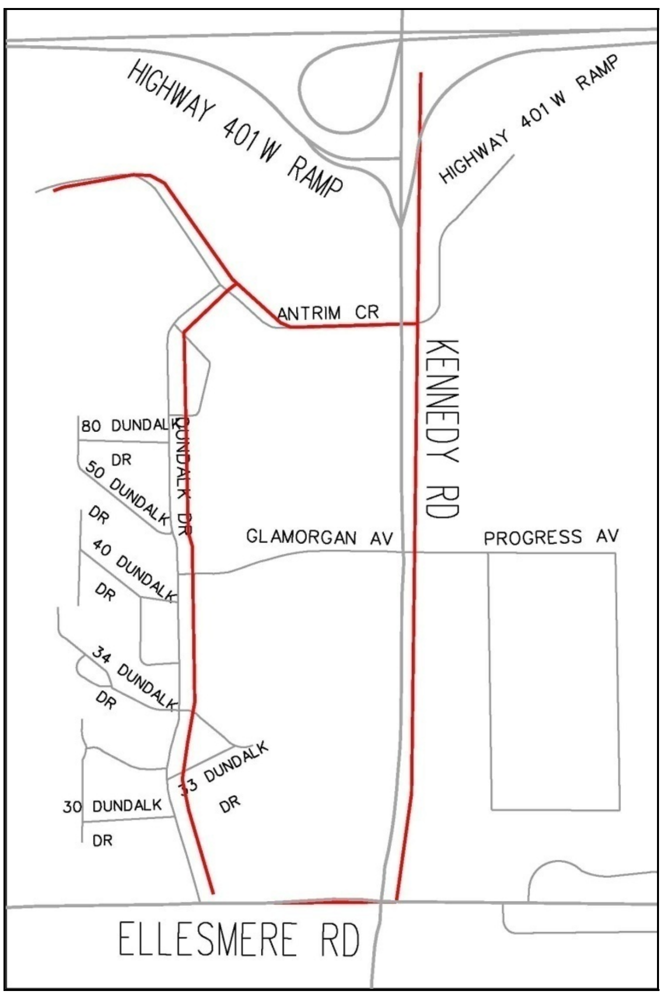


Figure 28: Map of Underground Rehabilitation of Feeder SCNAE5-1M29

25.5. Required Capital Costs

There are two phases to this job for a total of $3.91M.

Table 76: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
18653	E11421 Antrim Glamorgan Dundalk UG Rebuild SCNAE51M29 (Elec)	2013	$1.63
18652	E11421 Antrim Glamorgan Dundalk UG Rebuild SCNAE51M29 (Civil)	2012	$2.28
		Total:	**$3.91**

26. Underground Rehabilitation of Feeder NY53M25 (E11139, E12237)

26.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY53M25 in order to improve reliability of service and mitigate potential safety risks.

26.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 5

Table 77 presents the historical reliability performance of this feeder. The very high CI and CHI figures in 2009, as compared to 2010 and 2011, are primarily due to underground primary cable failures.

Table 77: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY53M25			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	19,054	563	1,393
Feeder CHI ***(Cumulative)***	10,648	1,167	920

This job rebuilds an area that has experienced direct buried cable failures.

26.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, replacing old direct-buried cable.

Table78: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	13,600 m	Primary Cable	13,600 m

26.4. Maps and Locations

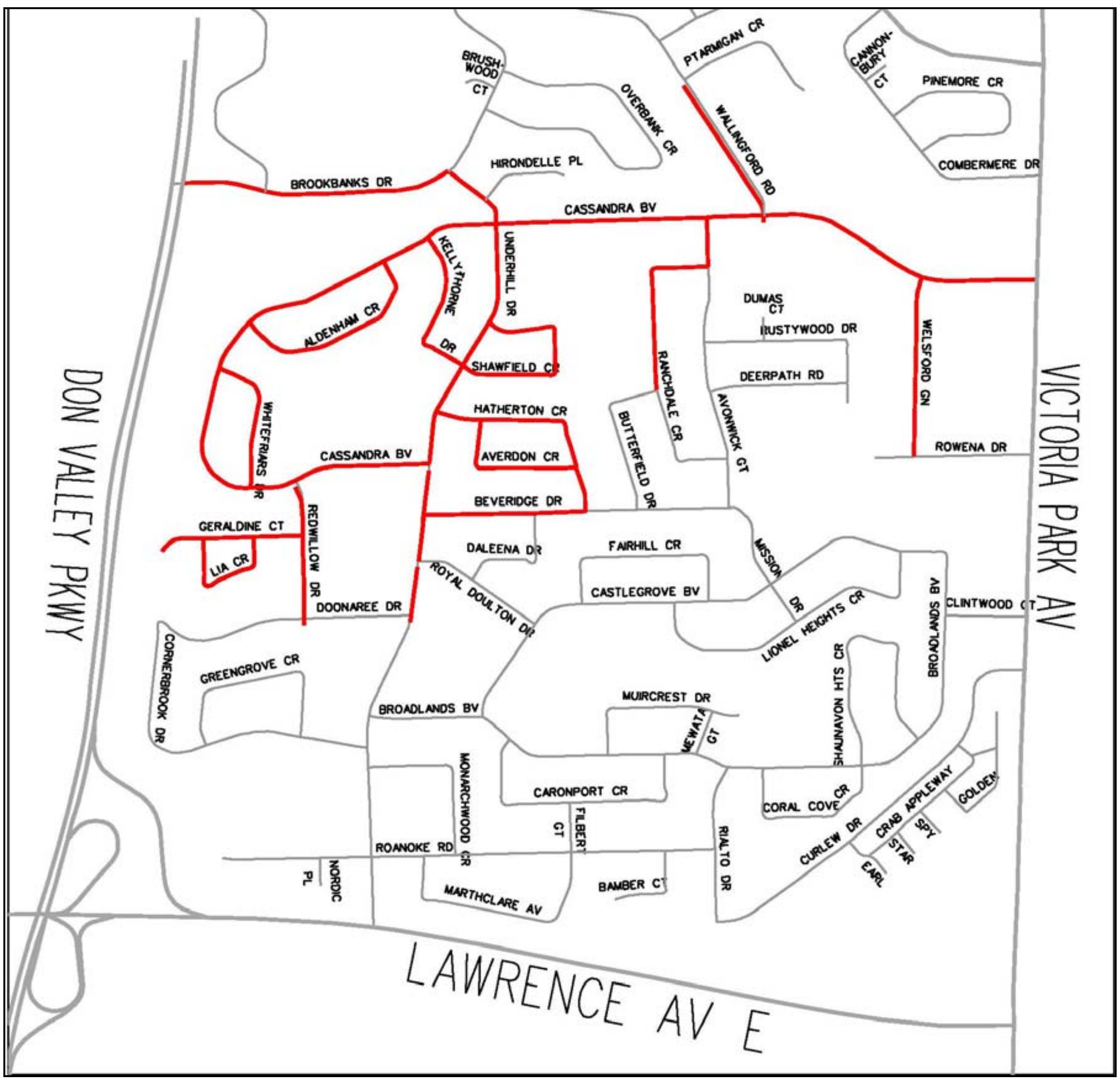
The assets being replaced by this job are located in the area bordered by Victoria Park Avenue to the east, the Don Valley Parkway to the west, York Mills Road to the north, and Lawrence Avenue East to the south. A map of the job area appears in Figure 29.

26.5. Required Capital Costs

There are two phases to this job for a total of $3.44M.

1 **Table 81: Required Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
25279	E11139 Cassandra UG Rebuild - Civil	2012	$2.40
20179	E12237 Cassandra NY53M25 UG Cable Rebuild (Electrical)	2013	$1.05
		Total:	**$3.44**



2 **Figure 29: Map of Underground Rehabilitation of Feeder NY53M25**

27. Underground Rehabilitation of Feeder NY80M9 (W12642)

27.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY80M9 in order to improve reliability of service and mitigate potential safety risks.

27.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 5

Table 80 presents the historical reliability performance of this feeder. The high CI and CHI figures in 2009, as compared to 2010 and 2011, are due significantly to underground primary cable failures.

Table 80: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY80M9			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	3,666	141	927
Feeder CHI ***(Cumulative)***	1,662	423	817

This job rebuilds an area that has experienced underground asset failures, including direct buried cable failures.

27.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 81: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	16,250 m	Primary Cable	16,250 m
Submersible Transformers	3	Submersible Transformers	3
Air-insulated Pad-mounted Switchgear	2	SF_6-insulated Pad-mounted Switchgear	2

27.4. Maps and Locations

The assets being replaced by this job are located in the northwest area of the intersection of Yonge Street and Sheppard Avenue. A map of the job area appears in Figure 30.

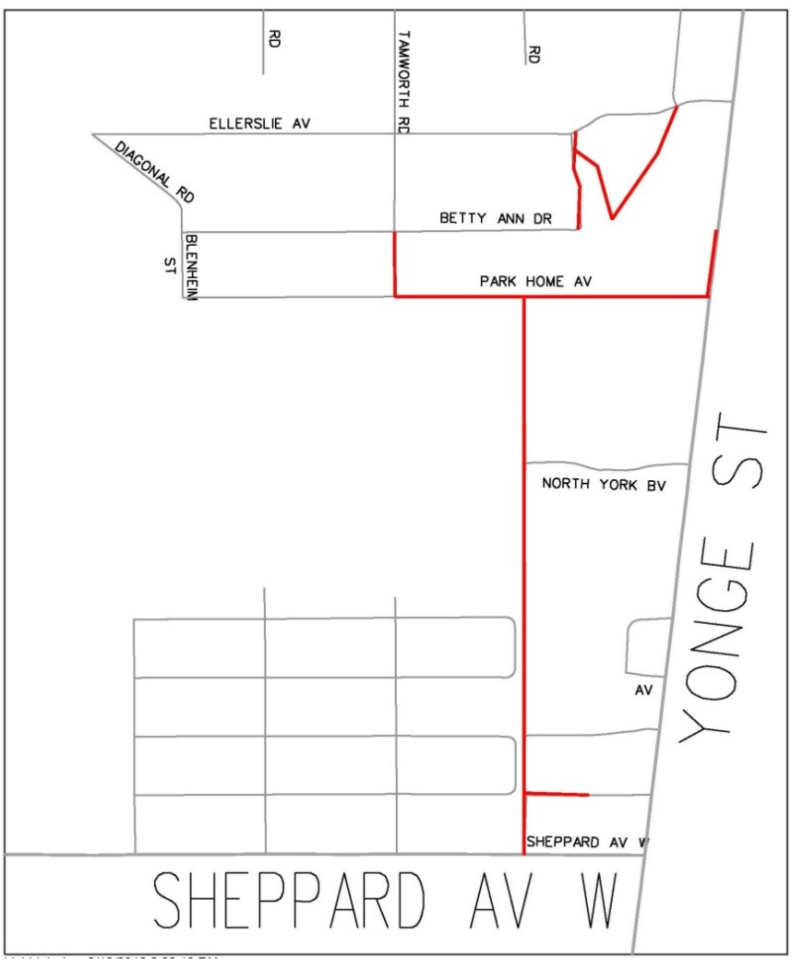


Figure 30: Map of Underground Rehabilitation of Feeder NY80M9

27.5. Required Capital Costs

Table 84: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
23023	W12642 UG Trunk and Lat Cable Rehab Beecroft	2014	$2.21
		Total:	**$2.21**

28. Underground Rehabilitation of Feeder SCNT47M3 (E11191, E11301, E11356, E11372, E11380, E11438, E11439, E12126, E12127, E12128, E12234 and E12235)

28.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNT47M3 in order to improve reliability of service and mitigate potential safety risks.

28.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 4

This feeder has held the rank of worst performing feeder on THESL's system for a few years. Table 83 presents historical reliability data for this feeder.

Table 83: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNT47M3			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	47,262	102,883	12,750
Feeder CHI ***(Cumulative)***	21,607	45,729	8,963

CI and CHI have been significant over the past number of years. The decline in CI and CHI in 2011 can be attributed to the many underground rehabilitation sub-jobs that were executed in 2010 and 2011, costing approximately $10 million. This job will address remaining direct-buried cable and air-insulated switches on this feeder, and are intended to provide long-term reliability improvement for this feeder.

28.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 84: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	66,450 m	Primary Cable	66,450 m
Submersible Transformers	13	Submersible Transformers	13
Air-insulated Pad-mounted Switchgear	10	SF_6-insulated Pad-mounted Switchgear	10
Air-insulated Vault-installed Switchgear	31	SF_6-insulated Vault-installed Switchgear	31

28.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Meadowvale Road to the east, Neilson Road to the west, Steeles Avenue to the north, and Highway 401 to the south. A map of the job area appears in Figure 31.

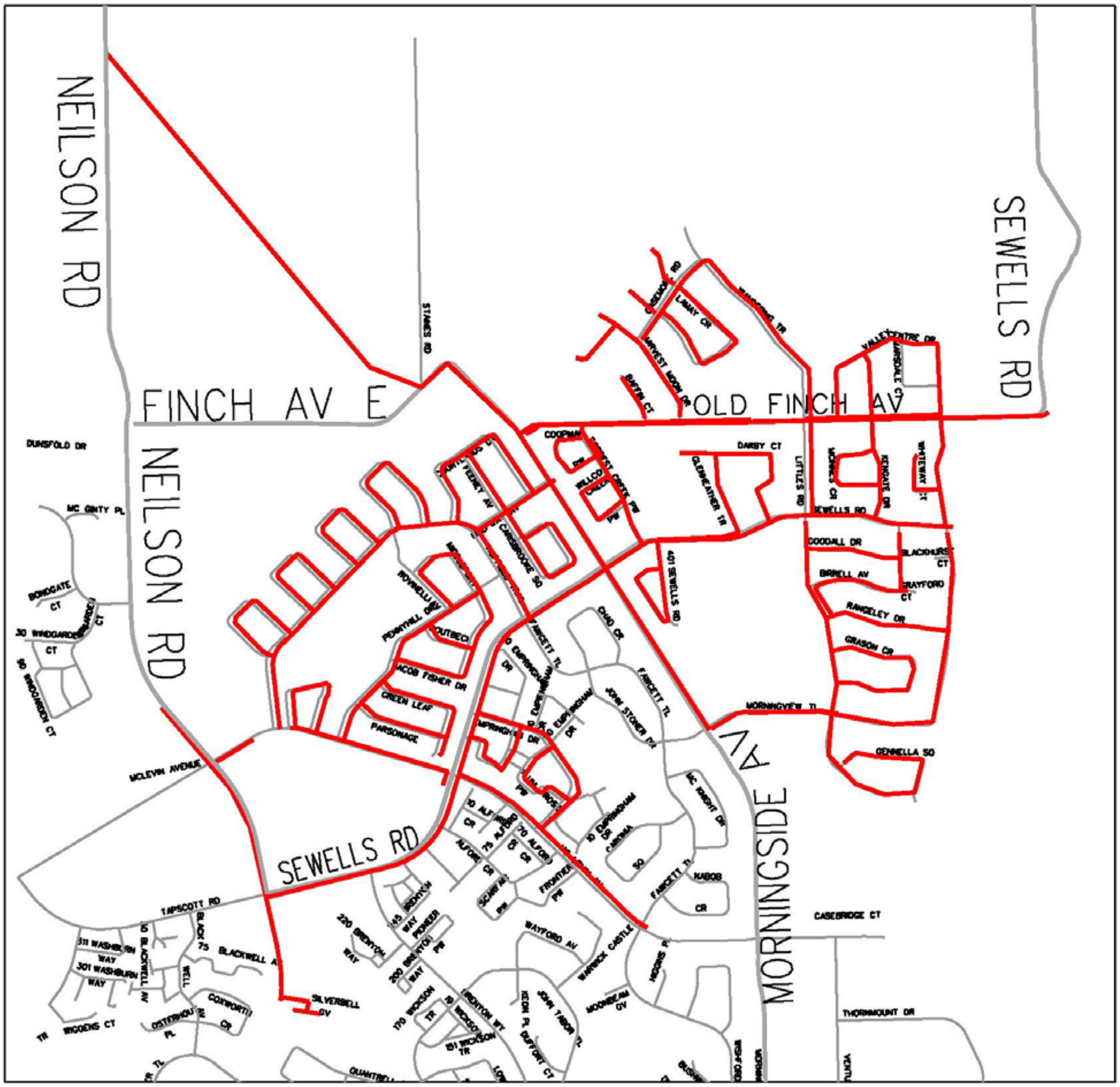


Figure 31: Map of Underground Rehabilitation of Feeder NT47M3

28.5. Required Capital Costs

There are 16 phases to this job for a total of $20.44M.

1 **Table 85: Required Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21506	E11191 FESI-12 McLevin/Alford UG rebuild NT4747M3	2012	$0.88
21853	E11301 FESI-12 Hupfield UG rebuild Phase 1 NT47M3	2012	$1.92
22356	E11356 FESI-12 Pennyhill UG rebuild NT47M3	2012	$1.00
21854	E11372 FESI-12 Hupfield UG rebuild Phase 2 NT47M3	2012	$1.33
22928	E11380 FESI-12 Empringham/McLevin UG rebuild NT47M3	2012	$1.84
20430	E12157 26M23 New Feeder to Morningside- Old Finch –Civil	2012	$1.71
18719	E11438 Old Finch UG Rebuild Phase 1 - Civil (47M3)	2012	$1.77
19623	E12126 Morningview SCNT47M3 UG Rebuild Phase 1 (Electrical)	2014	$0.64
19627	E12127 Morningview SCNT47M3 UG Rebuild Phase 2 (Electrical)	2014	$0.79
19629	E12128 Morningview SCNT47M3 UG Rebuild Phase 3 (Electrical)	2014	$0.79
20558	E12357 Extend UG R26M23 to Morningview 47M3	2013	$0.38
20432	E12319 26M23 New Feeder to Morningside- Old Finch –Electric	2013	$0.42
18720	E11439 Old Finch UG Rebuild Phase 1 - Electrical (47M3)	2013	$0.54

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
19622	E12126 Morningview SCNT47M3 UG Rebuild Phase 1 (Civil)	2013	$1.85
19626	E12127 Morningview SCNT47M3 UG Rebuild Phase 2 (Civil)	2013	$1.63
19628	E12128 Morningview SCNT47M3 UG Rebuild Phase 3 (Civil)	2013	$1.96
20169	E12234 Rebuild 3-Phase Neilson Industrial NT47M3 – Civil	2014	$0.71
20170	E12235 Rebuild 3-Ph Neilson Industrial NT47M3-Electrical	2014	$0.29
		Total:	**$20.44**

29. Underground Rehabilitation of Feeder SCNAH9M23 (E13121, E13147 and E13148)

29.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNAH9M23 in order to improve reliability of service and eliminate safety

29.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 4

Table 86 presents historical reliability data for this feeder. In 2011, there were a number of primary cable failures that contributed significantly to the increase in CI and CHI from 2010.

Table 86: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNAH9M23			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	1,963	1,163	10,042
Feeder CHI ***(Cumulative)***	433	135	7,207

This job rebuilds an area that has experienced a direct buried cable failure.

29.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new SF_6-insulated switchgear. Assets to be replaced include direct-buried cables and air-insulated switchgear.

Table 87: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	12,300m	Primary Cable	12,300m
Air-insulated Pad-mounted Switchgear	1	SF_6-insulated Pad-mounted Switchgear	1
Air-insulated Vault-installed Switchgear	26	SF_6-insulated Vault-installed Switchgear	26

29.4. Maps and Locations

The assets being replaced by this job are located in the vicinity of the intersection of Markham Road and Sheppard Avenue East. A map of the job area appears in Figure 32.

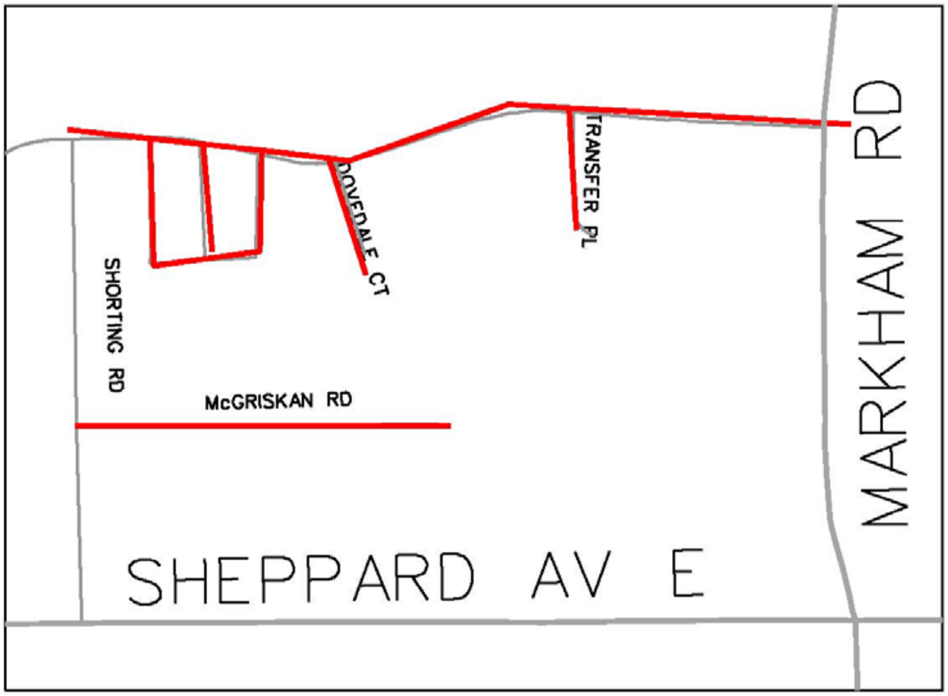


Figure 32: Map of Underground Rehabilitation of Feeder SCNAH9M23

29.5. Required Capital Costs

There are four phases to this job for a total of $2.71M.

Table 88: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21565	E13121 McGriskin Road UG Rebuild- Civil SCNAH9M23	2014	$0.28
21561	E13121 McGriskin Road UG Rebuild- Civil SCNAH9M23	2014	$0.19
21663	E13147 Nugget Avenue UG Rebuild Civil SCNAH9M23	2014	$0.91
21664	E13148 Nugget Avenue UG Rebuild Electrical SCNAH9M23	2014	$1.33
		Total:	**$2.71**

30. Underground Rehabilitation of Feeder NY51M3 (E12341, E12346, E12377, E12379, E12393, E12394, E12408, E12409, E10112)

30.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder NY51M3 in order to improve reliability of service and mitigate potential safety risks.

30.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 4

Table 91 presents historical reliability data for this feeder. There was an increase in underground asset failures in 2010 that contributed significantly to the high CI (compared to 2009 and 2011). Overall, there is a worsening reliability trend for this feeder.

Table 90: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY51M3			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	150	4,500	1,638
Feeder CHI ***(Cumulative)***	454	1,420	3,013

30.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 91: Asset Replacement

Assets to be Replaced		**New Assets to be Installed**	
Primary Cable	8,900 m	Primary Cable	8,900 m
Submersible transformer	54	Submersible transformer	54

30.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Don Mills Road to the east, Leslie railway to the west, Steeles Avenue East to the north, and Cummer Avenue to the south. A map of the job area appears in Figure 33.

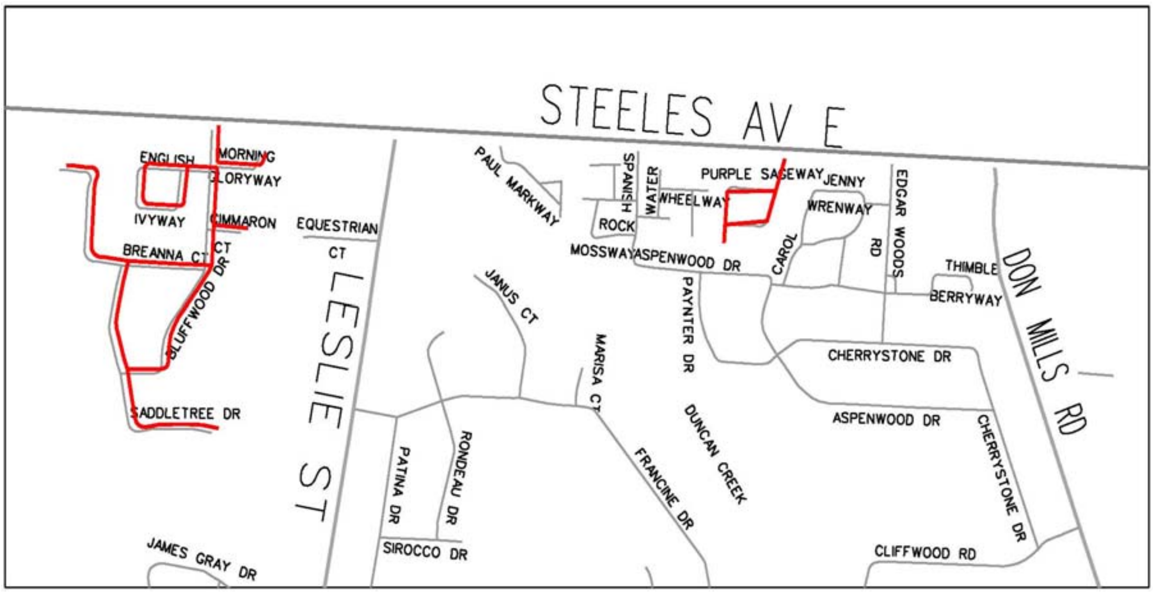


Figure 33: Map of Underground Rehabilitation of Feeder NY51M3

30.5. Required Capital Costs

There are nine phases to this job for a total estimated cost of $3.54M.

Table 91: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
24578	E12341 Bluffwood Saddletree Civil NY51M3	2014	$1.35
24849, 24846	E10112 Purple Sageway 51M3 UG replacement (Electrical & Civil)	2013	$0.43
20645	E12377 Goldenwood Road UG Rehab Electrical	2014	$0.32
20648	E12379 Pineway Craigmont Bruce Farm UG Rehab	2014	$0.13
20519	E12346 Bluffwood Saddletree Electrical NY51M3	2014	$0.14
20672	E12393 James Gray Drive UG Rebuild Elec NY51M3	2014	$0.18
20674	E12394 James Gray Drive UG Rebuild Civil NY51M3	2014	$0.37
20697	E12408 Thimble Berryway Aspenwood UG Rebuiild Civil NY51M3	2014	$0.45
20693	E12409 Thimble Berryway Aspenwood UG Rebuild Electrical NY51M3	2014	$0.17
		Total	**$3.54**

31. Underground Rehabilitation of Feeder SCNA47M17 (E11616, E12239, E12240, E12241, E12242, E12243, E12244, E12281, E12335 and E12336)

31.1. Objectives

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNA47M17 in order to improve reliability of service and mitigate potential safety risks.

31.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 3

Table 92 provides historical reliability data for this feeder. The decrease of CI and CHI in 2011 can be attributed to some underground rehabilitation work that was performed on this feeder in 2010 and 2011. This work carried a cost of nearly $8 million. This job will address remaining underground assets on this feeder that require replacement, and is expected to result in long-term reliability improvement of the feeder.

Table 92: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNA47M17			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	7,260	7,740	3,303
Feeder CHI ***(Cumulative)***	1,916	3,305	665

31.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 93: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	16,600 m	Primary Cable	16,600 m
Submersible Transformers	1	Submersible Transformers	1

31.4. Maps and Locations

The assets being replaced by this job are located in the vicinity of the intersection of Sheppard Avenue East and Kingston Road. A map of the job area appears in Figure 34.

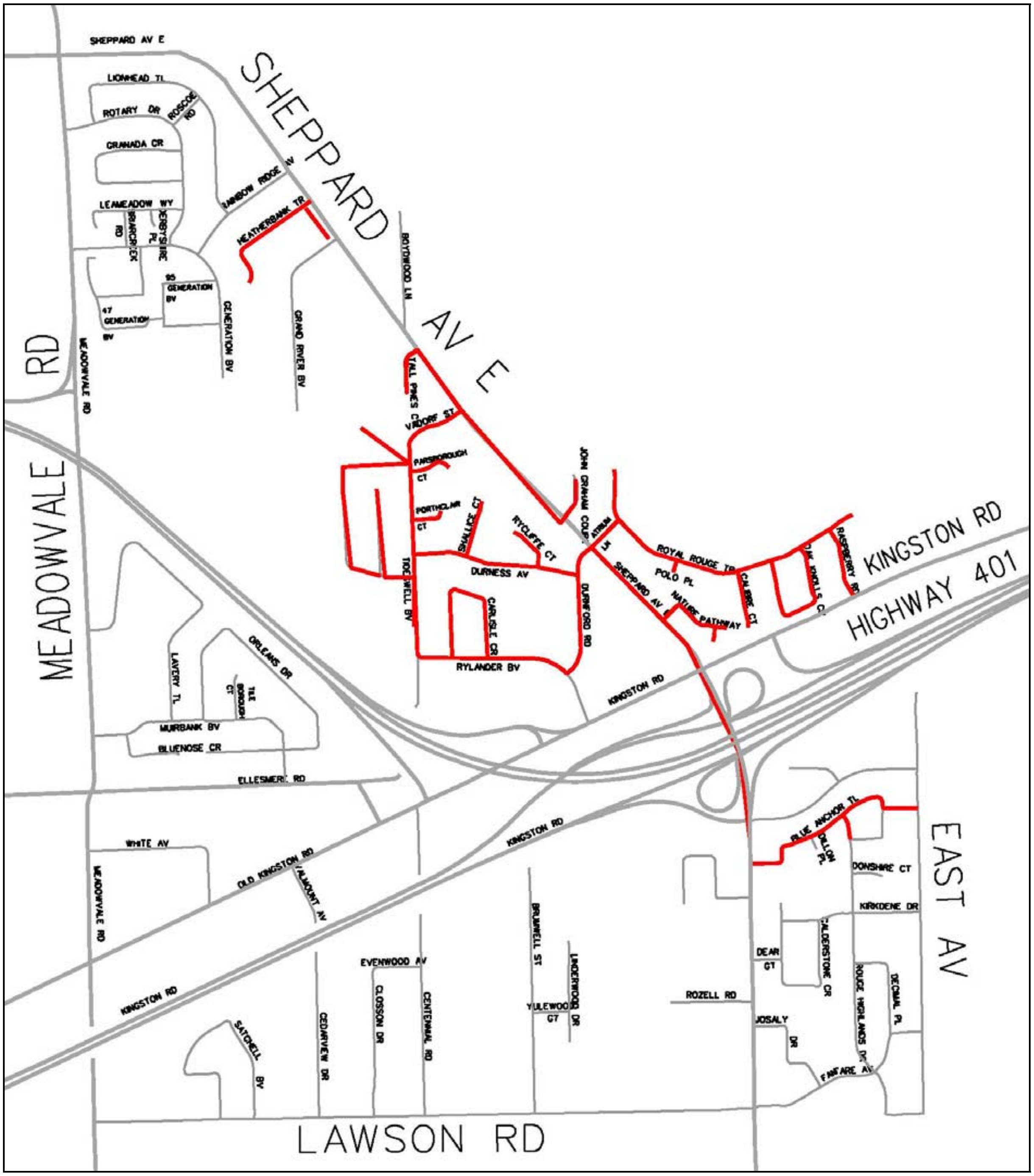


Figure 34: Map of Underground Rehabilitation of Feeder SCNA47M17

31.5. Required Capital Costs

There are ten phases in this job for a total estimated cost of $5.70M.

1 **Table 94: Required Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20207	E12239 Royal Rouge Trail UG Rebuild 47M17-Civil	2014	$1.06
20200	E12240 Durnford/Rylander/Tideswell 47M17 3-Ph Loop-Civil	2013	$0.89
20209	E12241 Rebuild Tallpine Subd and Durnford TH 47M17- Civil	2014	$1.53
20208	E12242 Royal Rouge Trail UG Rebuild 47M17-Electrical	2014	$0.19
20206	E12243 Durnford/Rylander/Tideswell 47M17 3-Ph Loop-Electric	2014	$0.28
20210	E12244 Rebuild Talpine Sub and Durnford TH 47M17- Electrical	2014	$0.32
20345	E11616 Meadowvale/Heatherbank 47M17 Cabling Civil	2014	$0.45
20313	E12281 Meadowvale/Heatherbank 47M17 Cabling Elec	2014	$0.48
20477	E12335 47M17 Blue Anchor UG Rebuild Electrical	2014	$0.04
20478	E12336 47M17 Blue Anchor UG Rebuild Civil	2014	$0.47
		Total:	**$5.70**

32. Underground Rehabilitation of Feeder SCNA502M21 (E13123, E13184, E14008, E14026)

32.1. Objective

The objective of this job is to proactively replace underground assets on the 27.6 kV feeder SCNA502M21 to improve reliability of service and mitigate potential safety risks.

32.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 2

This feeder has been experiencing worsening reliability, as is evident from Table 95. The majority of CI and CHI in 2009, 2010, and 2011 were due to underground primary cable failures.

Table 95: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNA502M21			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	7,099	4,814	8,992
Feeder CHI ***(Cumulative)***	941	1,534	6,298

32.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new SF_6-insulated switchgear. Assets to be replaced include direct-buried cable and air-insulated switchgear.

Table 96: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	16,742m	Primary Cable	16,742m
Air-insulated Pad-mounted Switchgear	4	SF_6-insulated Pad-mounted Switchgear	4

32.4. Maps and Locations

The assets being replaced by this job are located along Birchmount Avenue and Warden Avenue, south of Steeles Avenue East. A map of the job area appears in Figure 35.

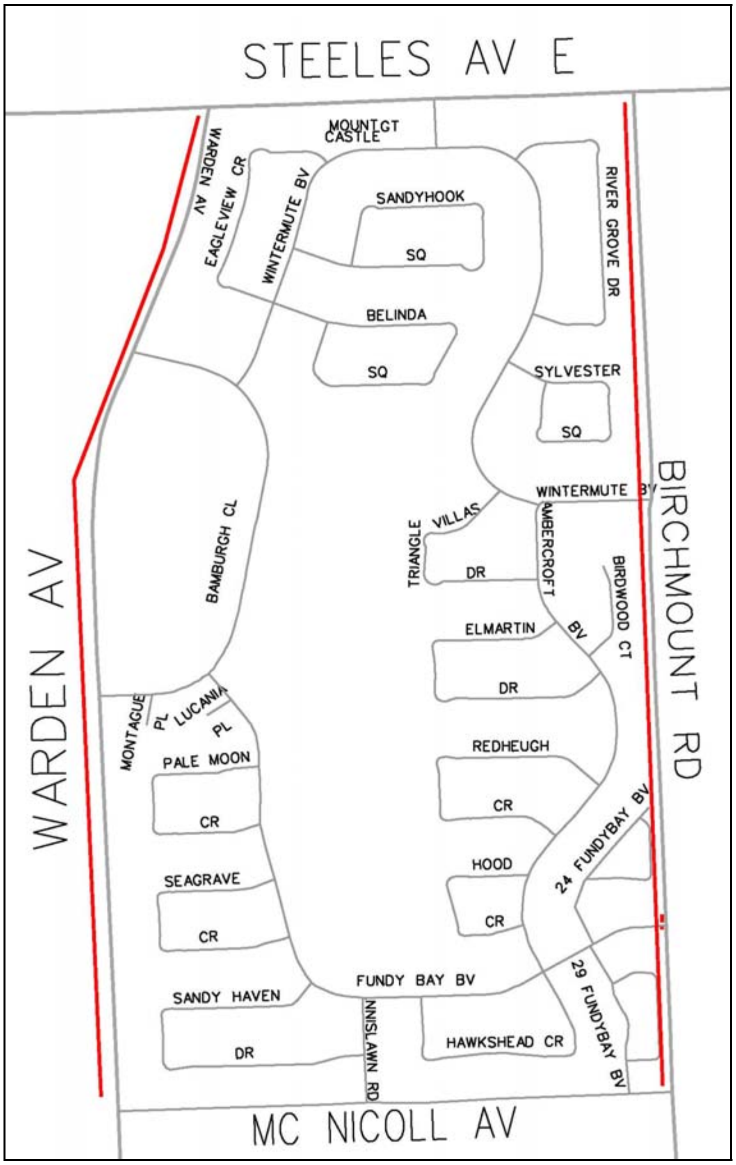


Figure 35: Map of Underground Rehabilitation of Feeder SCNA502M21

32.5. Required Capital Costs

There are four phases to this job for a total estimated cost of $3.44M.

Table 97: Required Capital Costs

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
21585	E13123 Rebuild Trunk 502M1 M22 Birchmount-Civil	2014	$0.88
21933	E13184 Rebuild UG Trunk 502M21-28 Warden -Civil	2014	$1.28
21586	E14008 Rebuild Trunk 502M1 M22 Birchmount - Electrical	2014	$0.40
21934	E14026 Rebuild UG Trunk 502M21-28 Warden -Electrical	2013	$0.88
		Total:	**$3.44**

33. Underground Rehabilitation of Feeder SCNT47M1 (E11087, E12195, E12210, E12212, E12213, E12225, E12288, E12299, E12300, E12316, E12520 and E13079)

33.1. Objective

The objective of this job is to proactively replace underground assets on 27.6 kV feeder SCNT47M1 in order to improve reliability of service and mitigate potential safety risks.

33.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 2

Table 98 presents the historical reliability of this feeder. The higher CI and CHI figures in 2010 are primarily due to a spike in overhead asset failures in 2010. The improvement in reliability in 2011 (and in 2010 if the overhead asset failures are removed from the data) are due to approximately $7 million in underground rehabilitation work completed in 2009. Prior to 2009, the feeder was experiencing an increasing number of underground asset failures. This job will address the remaining aged undergound assets on this feeder, including direct buried cable sections that have experienced multiple failures, in order to provide long-term reliability improvement for the feeder.

Table 98: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – SCNT47M1			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	6,436	11,039	2,151
Feeder CHI ***(Cumulative)***	3,493	7,163	143

33.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts, new SF_6-insulated switchgear, and new submersible transformers. Assets to be replaced include direct-buried cable, air-insulated switchgear and submersible transformers.

Table 99: Asset Replacement

Assets to be Replaced		**New Assets to be Installed**	
Primary Cable	58,680 m	Primary Cable	58,680 m
Submersible Transformers	16	Submersible Transformers	16
Air-insulated Pad-mounted Switchgear	4	SF_6-insulated Pad-mounted Switchgear	4
Air-insulated Vault-installed Switchgear	5	SF_6-insulated Vault-installed Switchgear	5

33.4. Maps and Locations

The assets being replaced by this job are located in the area bordered by Neilson Road to the east, Markham Road to the west, Finch Avenue to the north, and Highway 401 to the south. A map of the job area appears in Figure 36.

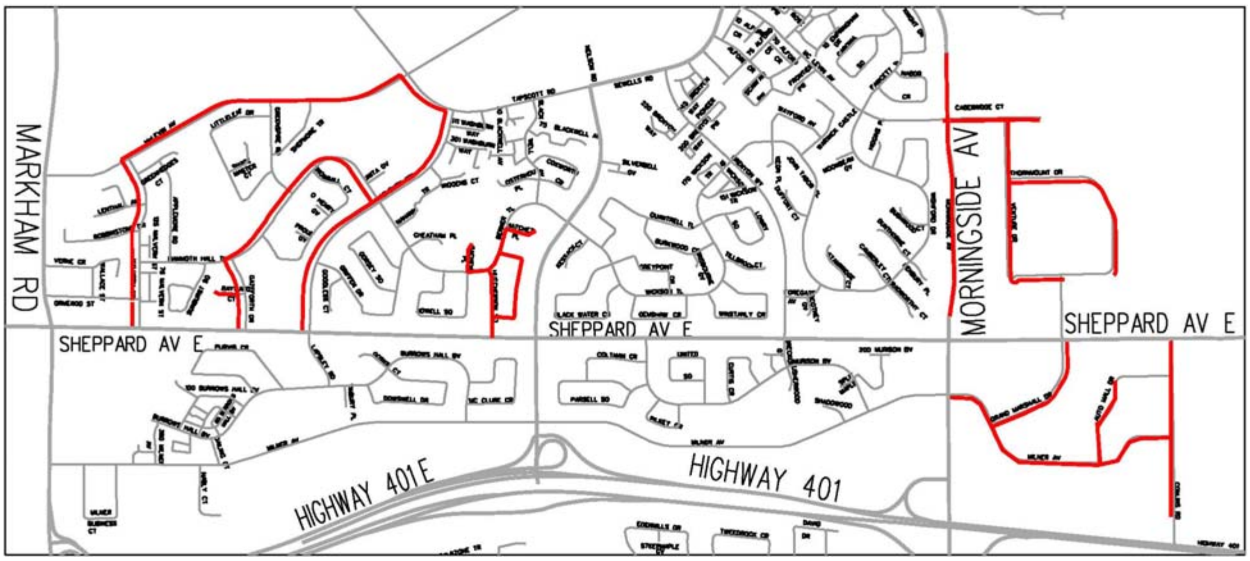


Figure 36: Map of Underground Rehabilitation of Feeder SCNT47M1

33.5. Required Capital Costs

There are 13 phases to this job for a total estimated cost of $14.91M.

1 **Table 100: Required Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
24664	E11087 Grand Marshall Cable Repl SCNT47M1 – Civil and Electrical	2012	$1.29
21287	E12520 UG Rebuild NT47M1 Conlins Milner- Civil	2012	$1.77
19999	E12195 Mammoth Hall UG Rebuild Civil NT47M1	2013	$3.42
20051	E12213 Morningside Avenue UG Rebuild Electrical NT47M1	2014	$2.05
20417	E12299 Gateforth Drive SCNT47M1 UG Rebuild (Civil)	2014	$0.27
21288	E13079 UG Rebuild NT47M1 Conlins Milner - Electrical	2014	$0.99
20383	E12288 NT47M1 - UG Rebuild in the Hutcherson Sq area Electrical	2014	$0.20
20388	E12300 NT47M1 - UG Rebuild in the Hutcherson Sq area Civil	2014	$0.26
20059	E12210 - Venture Drive UG SCNT47M1 - Civ / Elec	2014	$1.92
20058	E12212 Venture Drive UG Rebuild Civil SCNT47M1	2014	$1.39
20013	E12225 Mammoth Hall UG Rebuild Electrical NT47M1	2014	$1.21
20424	E12316 Gateforth Drive SCNT47M1 UG Rebuild (Electrical)	2014	$0.14
		Total:	**$14.91**

34. Underground Rehabilitation of Feeders NY85M1, NY85M9 and NYSS58F1 (W12490, W12435, W11614 and W11615)

34.1. Objective

The objective of this job is to proactively replace underground assets on feeders NY85M1, NY85M9 and NYSS58F1 in order to improve reliability of service and mitigate potential safety risks.

34.2. Historical Reliability Performance

Number of Unplanned Sustained Outages in 2011: 5

Table 101 provides the combined historical reliability performance of the feeders. These feeders, and in particular the areas being rebuilt by this job, have experienced underground asset failures, including direct buried cable failures.

Table 101: Historical Reliability Performance

HISTORICAL RELIABILITY PERFORMANCE – NY85M1, NY85M9 & NYSS58-F1			
Reliability Metric	**2009**	**2010**	**2011**
Feeder CI ***(Cumulative)***	2,191	3,359	10,731
Feeder CHI ***(Cumulative)***	1,825	3,380	6,602

34.3. Scope of Work

This job replaces both civil and electrical assets. This job installs new 28 kV Aluminum TR-XLPE cable in new concrete-encased ducts and new submersible transformers. Assets to be replaced include direct-buried cable and submersible transformers.

Table 102: Asset Replacement

Assets to be Replaced		New Assets to be Installed	
Primary Cable	4,380 m	Primary Cable	4,380 m
Submersible Transformers	3	Submersible Transformers	3

34.4. Maps and Locations

This job addresses assets in three areas. One area is southwest of the intersection of Finch Avenue West and Keele Street, and is illustrated in Figure 37. The second area is north of the intersection of Dufferin Street and Wilson Avenue, and is illustrated in Figure 38. The third area, as illustrated in Figure 39, is southwest of the intersection of Dufferin Street and Highway 401.

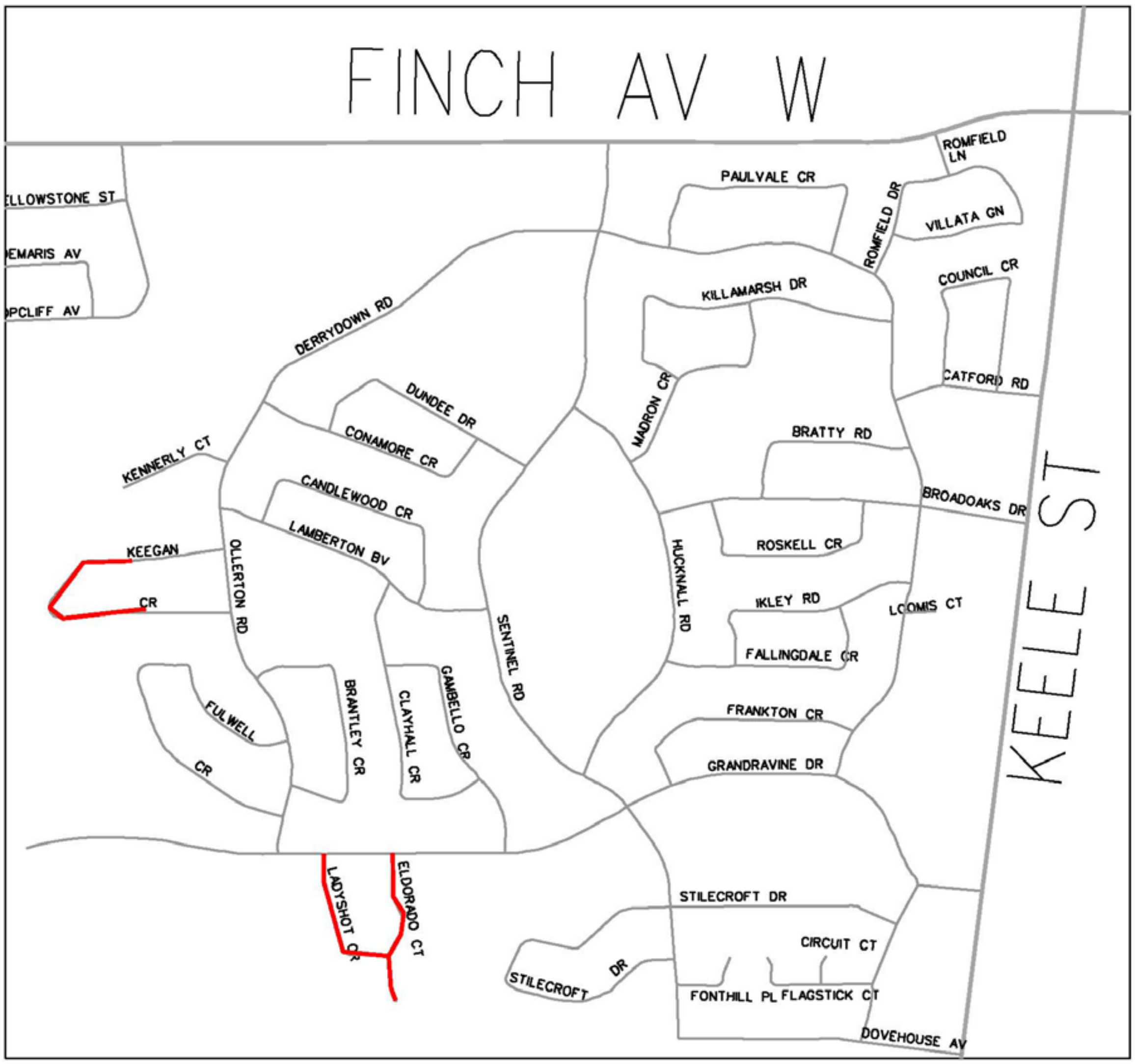
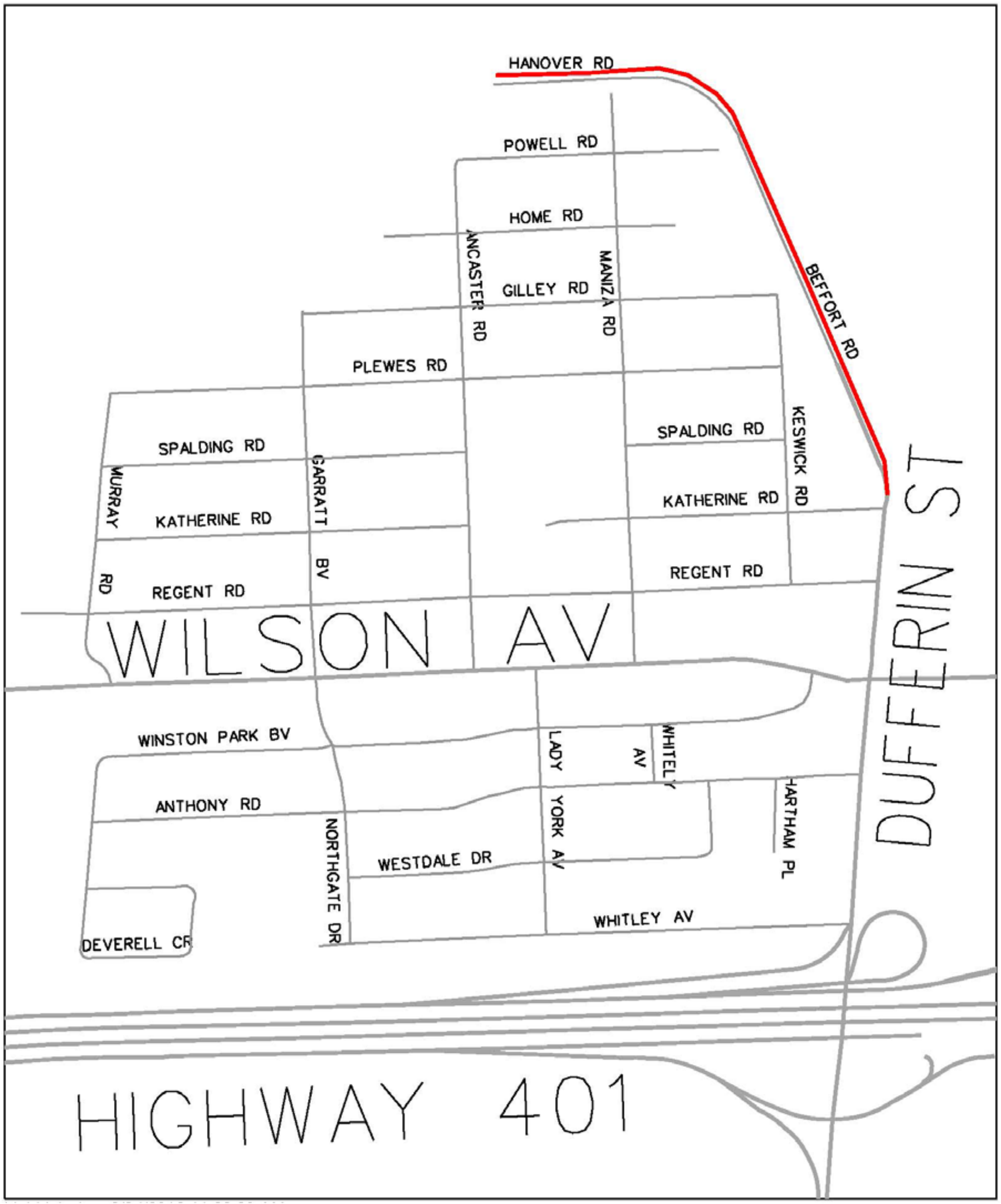


Figure 37: Map of Underground Rehabilitation of Feeder NYSS58F1



1 **Figure 38: Map of Underground Rehabilitation of Feeder NY85M1**

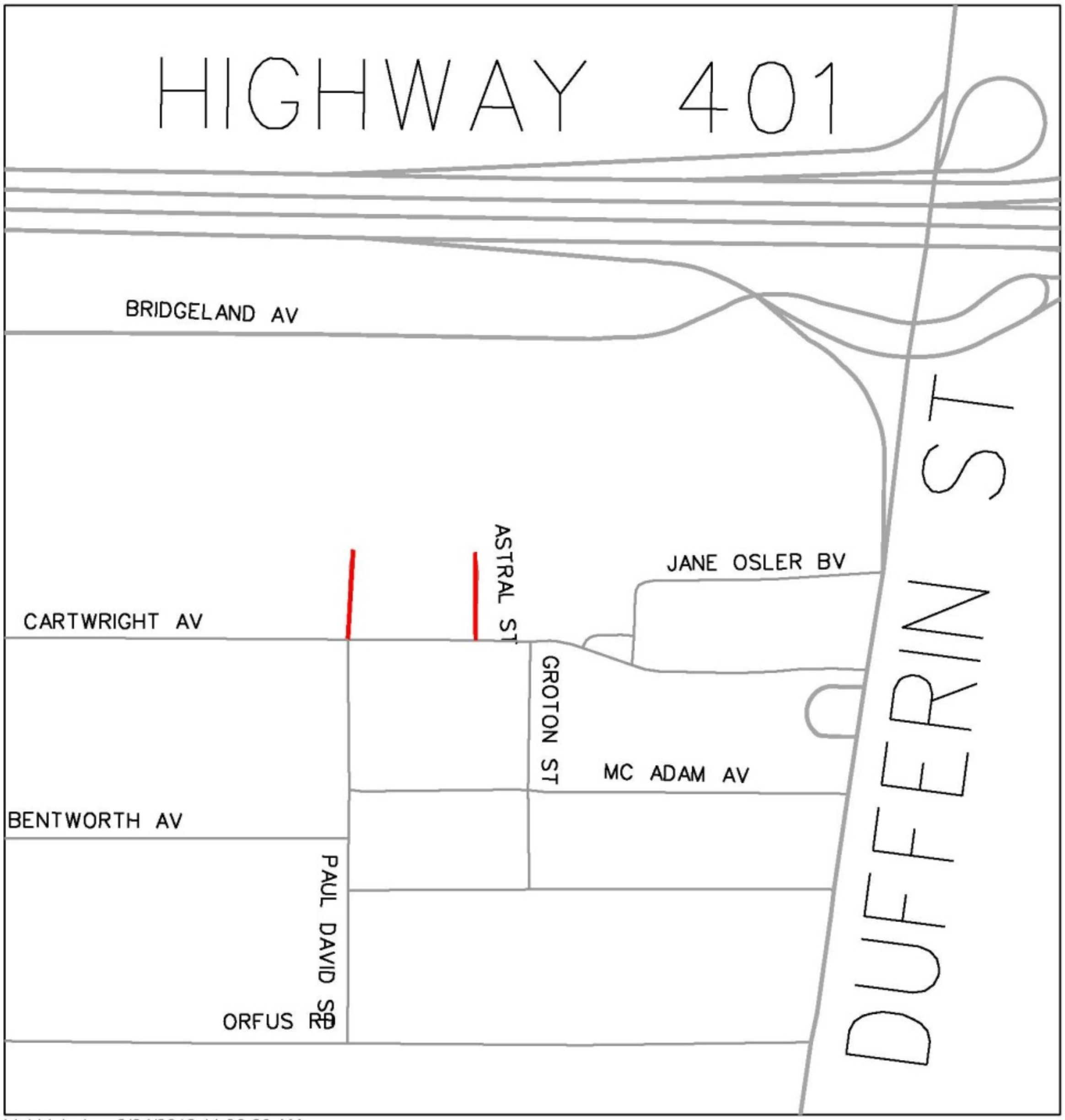


Figure 39: Map of Underground Rehabilitation of Feeder NY85M9

34.5. Required Capital Costs

There are four phases to this job for a total estimated cost of $2.66M.

1 **Table 103: Required Capital Costs**

Job Estimate Number	Job Phase	Job Year	Estimated Cost ($M)
20380	W11614 FESI LadyShot-Eldorado DB Cable Replace	2013	$0.69
22073	W11615 FESI Keegen Cr. DB Cable Replace	2012	$0.45
20812	W12435 Faul David and Astral UG DB Res'l Rebuild	2012	$0.55
20989	W12490 FESI-UG DB Cable Rehab Bombardier Supply	2013	$0.97
		Total:	**$2.66**

III NEED

1. Underground Direct Buried Cable

1.1. Overview

The installation of primary voltage XLPE cables directly into the ground – hence the term *direct buried* – dates as far back as the 1950s in the districts of North York, East York, York, Scarborough and Etobicoke within of the City of Toronto. These cables total approximately 877 circuit kilometers, representing approximately 7% of the underground primary cable in THESL's distribution grid. Sixty-six percent of these direct buried XLPE cables (580 circuit kilometers) are in need of immediate attention.

The most significant degradation process for XLPE cables is water treeing [Ref 1 – App A]. Water treeing and electrical treeing (the final stage of water treeing) are pre-breakdown phenomena associated with dielectric cable failure. Water treeing starts with the penetration of moisture into the cable insulation; these trees are microscopic tears within the dielectric. In the early stages of water treeing, the path between the conductor and the neutral still remains intact. However, over time, continuous seepage of moisture into the insulation and electrical stress allows ions from the conductor to start migrating into the microscopic tears. These voids then become carbonized and form electrical trees. Once this final stage of treeing is reached, the cable starts to fail rapidly due to internal short circuits that occur between the primary conductor and the neutral conductor on the outside of the cable insulation as shown in Figure 40.

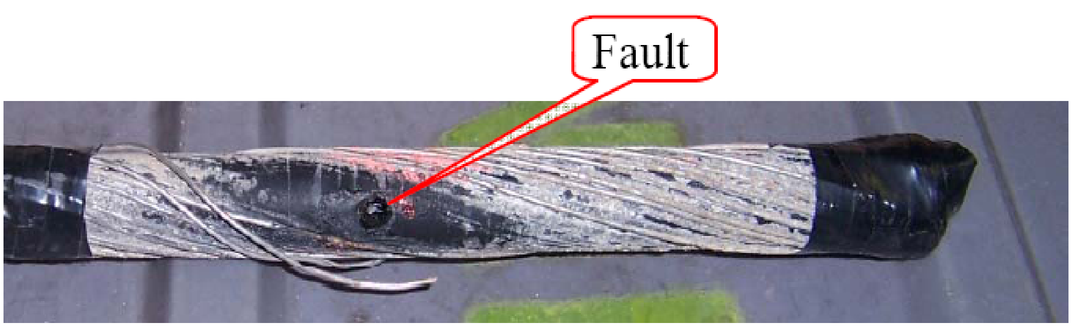


Figure 40: Fault due to premature insulation failure (taken on January 14, 2009)

Several studies show that water trees are diffused and indistinct. When moisture and voltage are removed from a cable, these trees disappear as well. However, the trees return upon re-immersion, indicating that the damage done to the cable is permanent and irreversible [Ref 9 – App A].

Based on direct buried cable failures over the past several years, and increasing reliability issues THESL faces from direct buried cables alone, it is known with some certainty that direct buried XLPE cables throughout the various districts within THESL's distribution system are laced with water trees that are resulting in an accelerated failure rate [Ref 8 – App A].

Average service life is not specifically provided by cable manufacturers as a part of cable specifications on product data sheets. This is mainly due to the fact the actual service life depends on various factors which include, but are not limited to, the following:

- Manufacturing quality
- Method of installation
- Installation environment
- Operating temperature
- Loading
- Ambient temperature of the installation environment (the lower the better)

Prior to 1990, XLPE cable manufacturing processes did not have sufficiently strict quality controls to keep out impurities from the insulation system and provide reliable sealing of the insulation system to prevent moisture ingress. Moreover, the steam curing process employed in the manufacturing of these early vintage XLPE cables resulted in moisture being trapped in the insulation system. Due to these defects, early vintage XLPE cables are more prone to water treeing and high rates of premature failure than newer generation XLPE cables. Newer generations of XLPE cables, known as tree-retardant XLPE (TR-XLPE) cables are not only strand-filled but also undergo improved manufacturing processes and controls that have been able to virtually eliminate unexpected insulation deterioration and premature hydrothermal aging.

Figure 41 presents the age demographic of direct buried XLPE cables. The majority of direct buried XLPE cables were installed prior to 1990 and therefore exhibit the aforementioned manufacturing defects.

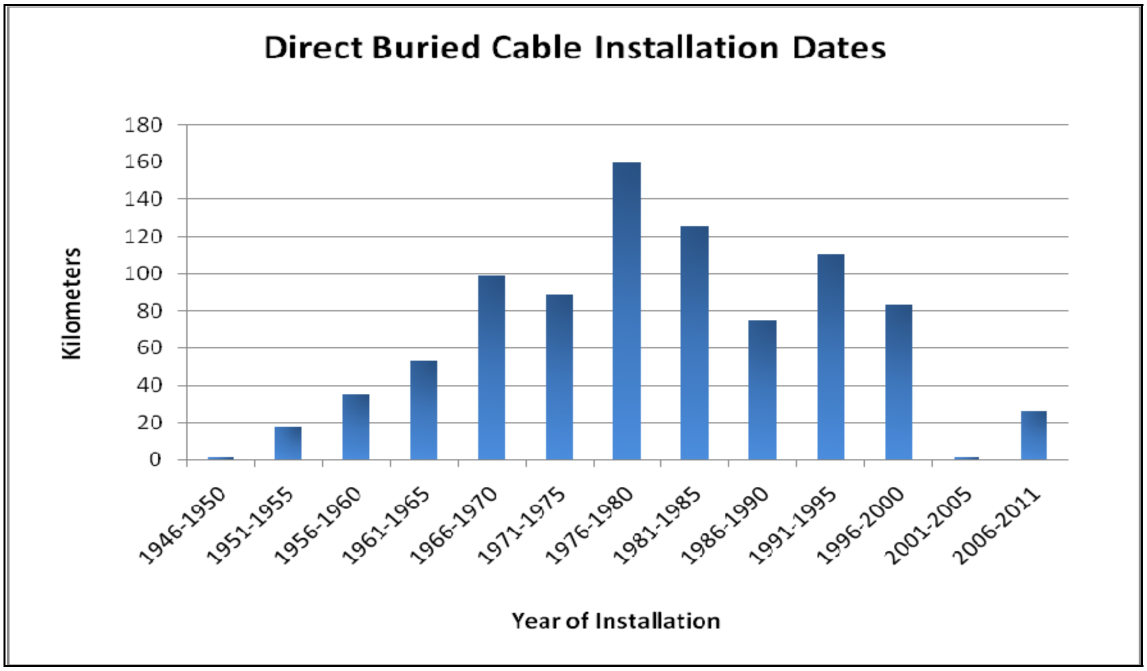


Figure 41: Age Demographic of Direct Buried Cables.

The way XLPE cables are installed also significantly impacts their service life. XLPE cables buried directly in the ground have a shorter service life than XLPE cables installed in conduit. Independent studies performed for THESL by Kinectrics indicate that the average useful service life of direct buried XLPE cable is 22.5 years and if the cable is installed within conduit it may prolong the useful life to an average of 50 years [Ref 1 – App A]. Similarly, Consolidated Edison Company of New York ("Con Edison"), the company that provides electric service to New York City, has reported that their primary underground direct buried cables have an average service life of 24.5 years [Ref 10 – App A]. It should be noted that this useful life is a benchmark and past studies performed by Ontario Hydro [Ref 2 – App A] show that direct buried XLPE cables experience the highest failure rates between nine and 12 years after initial installation.

It is not only THESL that is experiencing premature failure of direct buried primary cables. Several utilities across North America have reported an unexpected increase in failures due to their direct buried underground assets. Con Edison is one such utility. Con Edison has indicated in its Infrastructure Investment Panel report [Ref 10 – App A] that 60% of its Underground Residential Distribution interruptions in recent years have been due to insulation breakdown of direct buried primary and secondary cables. Con Edison plans to replace all direct buried primary and secondary cables with cable in conduit over the next 20 years.

1.2. The Impact of Moisture on Cable Insulation Integrity

Although XLPE cables are designed to be fully submersible, constant contact with moisture along with the heat generated from the cable itself work towards premature degradation of the cable. This effect is magnified in early vintage cables due to their inherent manufacturing defects. Also, this effect presents a problem mainly for direct buried XLPE cables, as XLPE cables installed in conduit are isolated from the environment due to the presence of the conduit.

At a depth of 1 meter, most soil has a relative humidity of 100% for the entire year; this does not include the local effects of irrigation and hence generally understates the water content present in the soil. Therefore, it is fair to say that most direct buried cables lay in soil at 100% humidity almost all the time during their entire service life. It should be noted that this humidity level may vary for cables passing under a well-drained roadway compared to cables installed below irrigated grass [Ref 3 – App A].

The World Weather Organization has reported that the City of Toronto has a fairly mild climate with average annual precipitation (including rain and snow) of 834 mm with roughly 145 days of precipitation per year [Ref 4 – App A]. This means that the climate of Toronto, together with the general settings of the underground environment amount to very inhospitable surroundings for direct buried XLPE cables.

1.3. Safety Hazards

Direct buried cables have no mechanical protection and are at risk of being hit with shovels and other excavation equipment. According to the Electrical Safety Authority (ESA), between 1998 and 2006 there were a total of 337 reported contact incidents on underground cables due to dig-ins in Ontario. Sixteen serious incidents in Ontario due to dig-ins were reported to the ESA between January 2006 and April 2007 [Ref 15 – App A].

From 2001 to 2009, the ESA reported a total of 662 contact incidents with respect to underground cable assets [Ref 16 – App A]. Despite administrative controls in place to identify underground cables before excavation begins, 4% and 7% of all underground cable outages which occurred in 2010 and 2011, respectively, were attributed to dig-ins. Therefore, direct buried cables continue to present a potentially serious safety risk to field crews and the general public.

1.4. Environmental Impact

In some cases, when direct buried cables are decommissioned, it is not feasible to remove them from the earth due to factors such as municipal road moratoriums. Although there is no particular study indicating the long-term effects of these cables in the ground, due diligence and environmental responsibility dictates that when possible, the cables should be removed and disposed of. Installing cables in conduit would allow THESL to always remove failed and/or decommissioned cables.

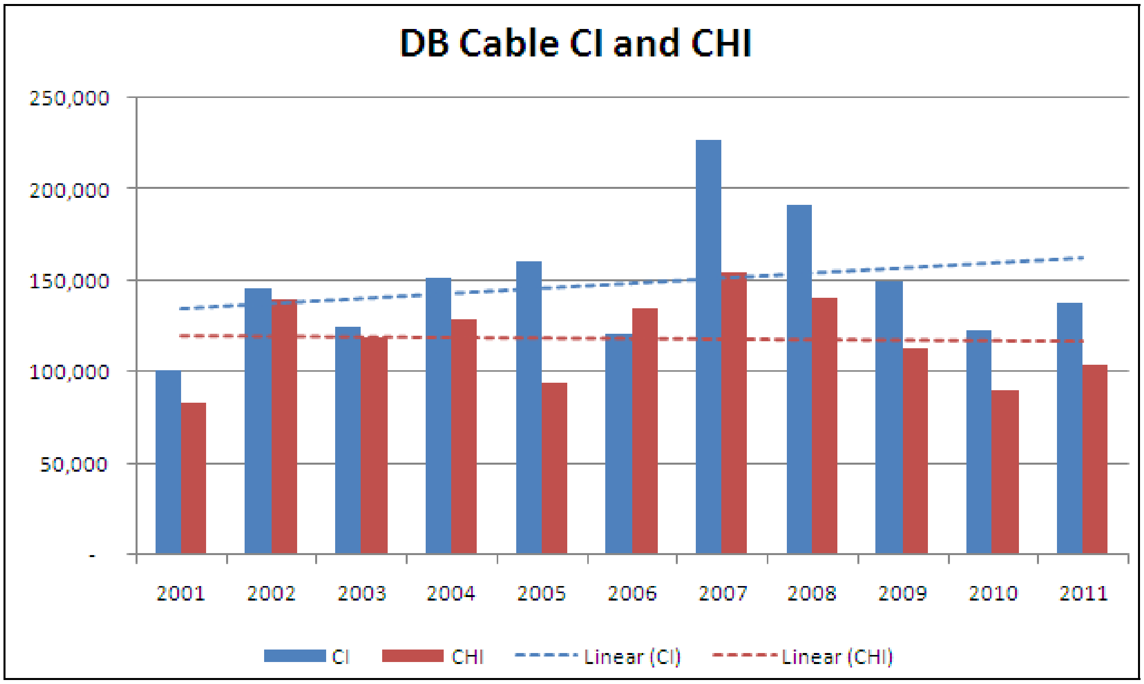
1.5 Reliability

While direct buried cable replacement jobs between 2007 and 2010 allowed for some improvements to reliability over the same period, recent reliability degradation in 2011 suggests that the remaining direct buried cables are still continuing to fail at a rate faster than planned work can be executed.

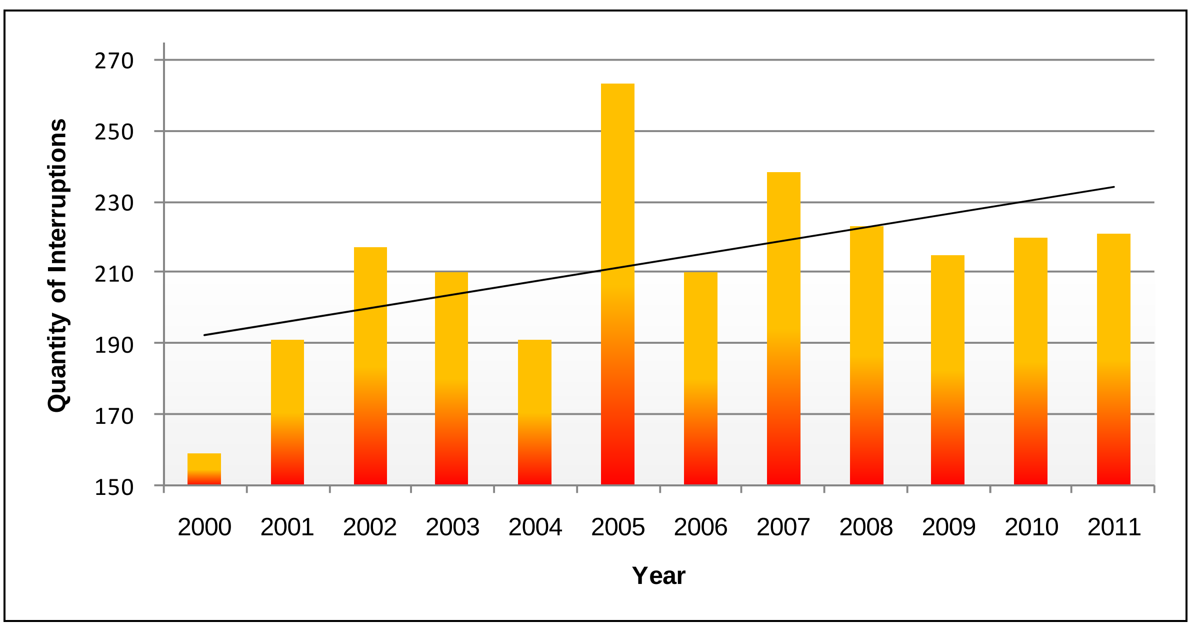
The effects of accelerated hydrothermal aging (which include water and electrical-treeing) on THESL’s direct buried cables have started to become more and more apparent and have resulted in a decline in system reliability. Customer Interruptions (CI) have shown an overall increasing trend since 2001. This is illustrated in Figure 42. In addition, the total number of sustained interruptions or outages has also been increasing steadily over the past ten-year period, as seen in Figure 43.

Both graphs illustrate a significant spike in outages, CI and CHI results in 2007 and 2005 respectively. Recent efforts to replace this existing direct buried cable infrastructure with new strand-filled TR-XLPE cables in concrete-encased conduit resulted in reliability improvements from 2007 to 2010. However, as can be seen in 2011, the remaining direct buried cables are continuing to fail and further degrade underground system reliability at a rate faster than planned work can be performed. While there was not a tremendous increase with respect to the quantity of outages between 2010 and 2011, the CI and CHI increases in 2011 suggest that these outages had a high impact of failure.

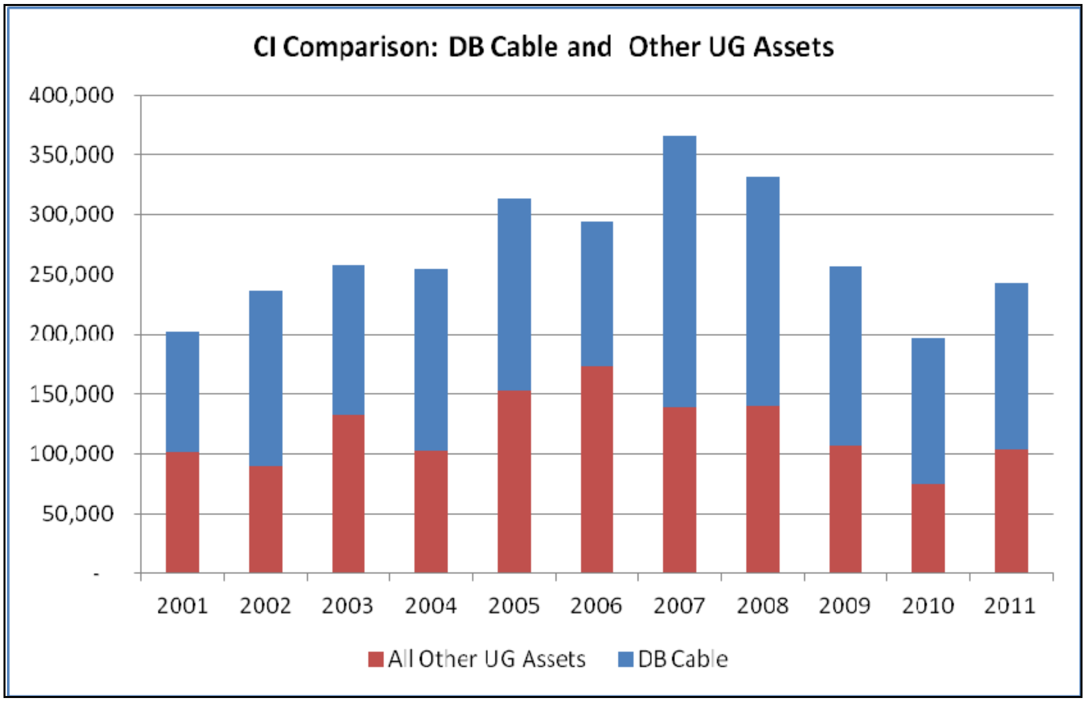
Figures 44 and 45 compare the CI and CHI impacts due to direct buried cables against the entire underground distribution system (including all primary cables). These figures both illustrate that the majority of interruptions attributed to underground system infrastructure have been attributed specifically to direct buried cable.



1 **Figure 42: Customer Interruptions (CI) and Customer Hours Interrupted (CHI) due to outages**
2 **attributed to direct buried cable failures.**

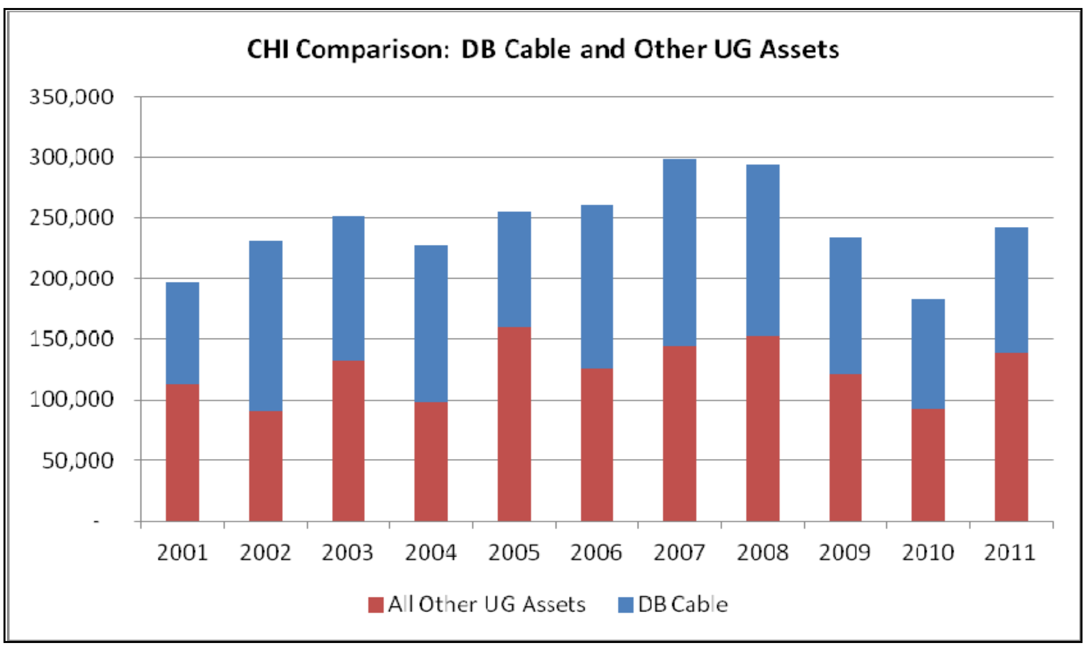


3 **Figure 43: Number of interruptions attributed to direct buried cable failures. Each**
4 **interruption increases the Feeders Experiencing Sustained Interruptions (FESI) count.**



1 **Figure 44: Customer Interruptions (CI) due to direct buried cable versus all other underground**

2 **assets**



3 **Figure 45: Customer Hours Interrupted (CHI) due to direct buried cable versus all other**

4 **underground assets**

In 2011, 57% of all customer interruptions (CI) and 43% of all customer hours interrupted (CHI) due to underground asset failures were specifically related to direct buried cables. This percentage is expected to continue to increase as more of THESL's direct buried cables exceed their useful service life.

There is an immediate need to address the issues associated with direct buried cables, from both a safety and system reliability perspective. Pro-actively replacing direct buried cables with strand-filled tree-retardant cross-linked polyethylene (TR-XLPE) cables in concrete-encased ducts is the most prudent and cost-effective solution. TR-XLPE cables use super-smooth, extra clean materials and employ triple extruded, dry cure processes which are intended to reduce impurities and moisture in cable insulation. The incorporation of a Poly Vinyl Chloride (PVC) or Polyethylene (PE) jacket, metal foil barriers and other water migration controls further reduces the incidence of moisture ingress, which can lead to the formation of water-trees, and ultimately to failure of the cable insulation.

The concrete-encased ducts provide improved mechanical protection against external factors and contamination from the surrounding soil and underground environment. In addition, because these cables are installed in conduit, faulted cable segments are able to be completely and efficiently replaced.

2. Air-Insulated Pad-Mounted Switchgear

2.1. Overview

Air-Insulated Pad-Mounted switches are essential components in the distribution system, used for feeder load switching, isolation and emergency power restoration procedures. THESL has traditionally used air-insulated pad-mounted switches in the 27.6 kV distribution system.

Typical air-insulated pad-mounted switches feature four compartments containing a set of either switches for switching or isolation operations, or fuses for protection. Figure 46 illustrates two circuit configurations of a four-way air-insulated pad-mounted switchgear unit. These switch configurations are commonly used on the trunk part of a feeder. When there is a need to transfer load from one feeder to another, individual switches can be operated to either close or open such that power can be diverted from one feeder to another. Currently Toronto Hydro has approximately 800 pad-mounted switches installed in the field.

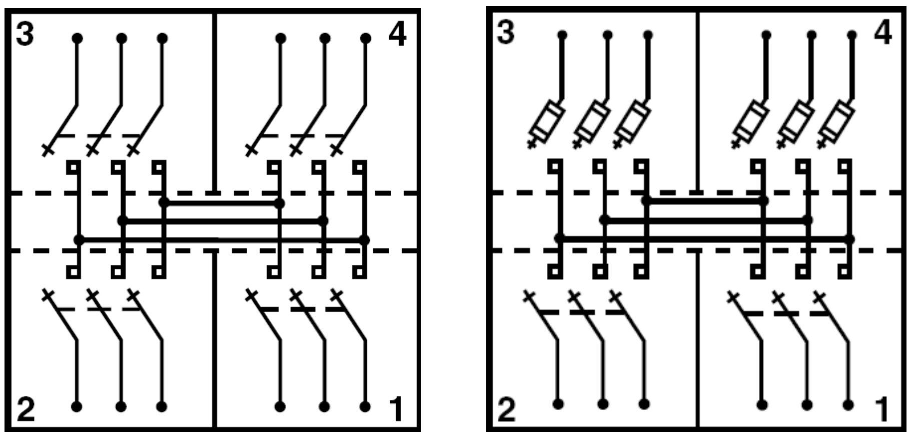


Figure 46: Four-way air-insulated pad-mounted switch configurations

Air-insulated pad-mounted switch failure is a major contributor to outages within the THESL underground distribution system. Over the last ten years, there has been an increasing trend of failures for this asset class as illustrated in Figure 47. Since an air-insulated pad-mounted switch can be used to connect up to four different feeders, in the event of a total failure of the unit, all four feeders will experience a power outage resulting in a loss of supply to a large number of customers. These assets have suffered an annual failure rate of 5% to 10% of the total population during the last five years and this trend is expected to increase further in the future unless mitigation action is taken. According to THESL's historical outage data, failure of this asset typically results in an outage to an average of 1,400 customers for an average duration of 50 minutes per incident. In addition, due to the design of the switchgear, the unit may sometimes fail in a violent manner in which in the energy from the internal arcing fault would cause substantial damage to the equipment enclosure and subject the operator or maintainer of the unit to serious physical injury.

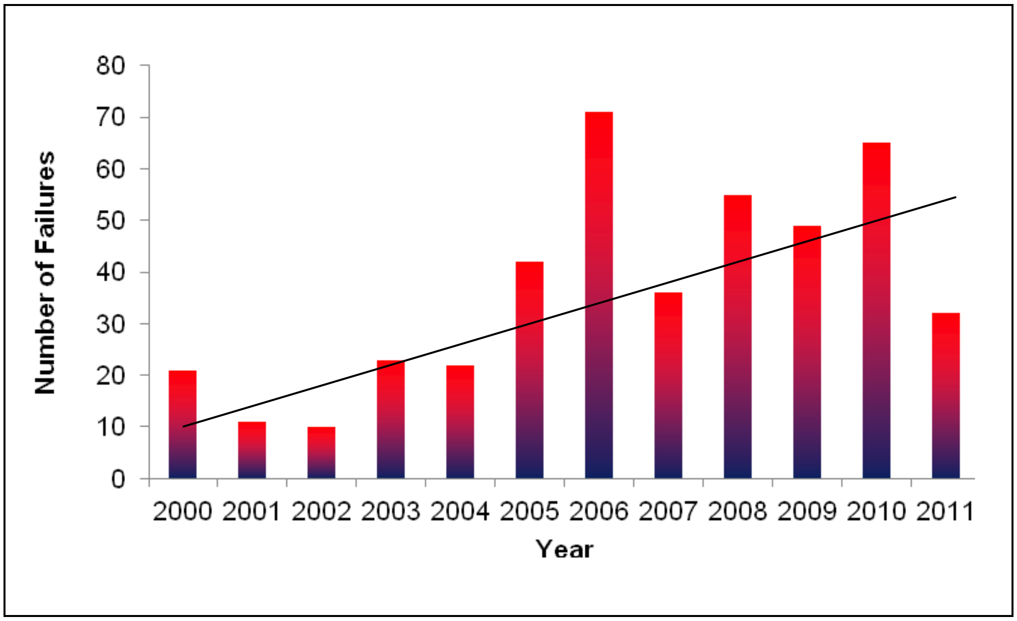


Figure 47: Air-insulated Pad-Mounted Switch Failure Rate

2.2. Contamination Ingress and Failure

Air-insulated pad-mounted switches are designed to be naturally vented through louvers under the hood of the enclosure. This results in ingress of airborne particles, such as dust and road salt, into the switching compartments. Other sources of contamination include the concrete foundation which the air-insulated pad-mounted switch is situated on top of, where primary cables attach to the fusing and switching compartments. These cables may be tightly packed within the enclosure, creating an environment with tight clearances and an increased potential for moisture formation. These contaminants will ultimately land and accumulate over time along the barriers separating the different phases of the switchgear, and along the other components contained within the asset. Although scheduled preventive maintenance is effective in removing this excessive buildup of contaminants, it is only effective for a limited time, until contaminants build up again. Hence, in reality, preventative maintenance is ineffective in preventing the escalating failure rate as it cannot eliminate the failure mode of ingress of air borne contaminants. This is discussed further in a later section.

Moisture from the external environment will also enter the cubicle and become trapped within. As the ambient temperature changes, the trapped moisture condensates and turns into water, dampening the dirt and other contaminants that are already present on the insulation surface. The surface at this time becomes conductive and, at the beginning, a small amount of leakage current starts to flow across the insulation surface between live terminals or between a live terminal and ground. This discharge phenomenon burns the insulation material and creates carbonized tracks. These tracks in turn allow higher magnitudes of leakage current to flow over the surface and result in greater tracks.

The term “tracking” describes the flow of electrical energy over an insulation surface but is not high enough to cause protective devices to operate. Over time, tracking on the insulation surface degrades the strength of the insulation material and eventually causes a discharge of a higher magnitude of energy, known as a flashover. A flashover may also result from partial electrical discharge in the air, known as corona, due to contaminants and moisture.

The result of a flashover is a near simultaneous ignition of all combustible material within the compartment. The flashover also releases an ionized gas that travels to other compartments in the enclosure. This ionized gas is conductive and will result in the discharge of electrical energy within the other compartments of the asset. This ultimately results in additional flashovers and combustion that leads to the total failure of the asset. If an air-insulated pad-mounted switch is connected to four different feeders, then this flashover event will likely result in a loss of power to all of these feeders, thus creating an outage to a large number of customers.

It is believed that the accelerated failure rate of air-insulated pad-mounted switches is due to this insulating medium breakdown process. This is in alignment with the increasing frequency of reports from both THESL and contractor crew workers of corona activity being heard from within the asset when within close proximity. There is also a potential safety risk that is present when accounting for the live-front design where all energized components are exposed to the crew worker when inspection and maintenance activities are being performed.

Figure 48 highlights a failed air-insulated pad-mounted switch. As illustrated in the picture, the switch has evidence of excessive dirt and contamination buildup on the termination and insulators. The switch endured severe damage from a fire and internal explosion, such that the door was dislodged from the frame.

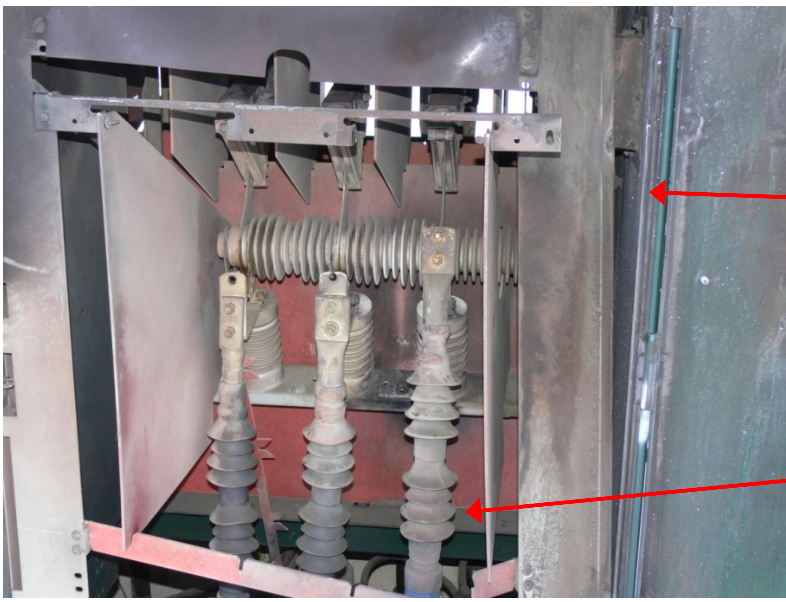


Figure 48: Failed Air-insulated Pad-Mounted Switch (Taken November 19, 2008)

2.3. Safety Hazards

The catastrophic failure mode associated with air-insulated pad-mounted switches presents a potential safety risk.[2] Exposure to the energy of the flashover may result in a serious injury. Anyone near the switch enclosure may be injured due to dislodging of the door or other external parts of the enclosure.

[2] The terms 'catastrophic failure', 'fail catastrophically', and related forms, are used throughout the business cases presented in this Application. These terms refer to a mode of failure of an electrical distribution component in which incidental damage to other equipment and/or injury to a person occurs or could occur, in addition to the loss of the electrical distribution function of the component itself. Explosive arc flashes, fires, falling debris, and structural collapse are examples of catastrophic failure. Catastrophic failure is distinguished from failure-by-design and simple failure modes in which a component, such as a fuse, performs according to design to interrupt the flow of electricity or otherwise ceases to perform its electrical distribution function without creating actual or potential damage or injury to adjacent equipment or persons in the vicinity.

There is a documented incident on October 7, 2006, where a THESL Protection and Control employee suffered facial burns while performing a routine inspection of an air-insulated pad-mounted switch. While opening a compartment door, debris from the environment initiated a flashover event in which a fireball resulted in facial burns to the employee. This incident could have had a far worse outcome.

2.4. Mechanical Defects

THESL recently determined that a batch of air-insulated pad-mounted switches manufactured between 2004 and 2008 have potentially defective mechanical springs, which can result in another serious air-insulated pad-mounted switch failure mode.

These mechanical springs are used as part of the switching operation for these assets. The stored energy in the spring is utilized to move the switch from one position to another (i.e., open to close). The defective spring in the affected units would either render the switch inoperable, thereby prolonging the power restoration time where the switch is being used to re-route power, or break during a switching operation, leaving the switch in a partially open or closed position.

The latter is a very serious failure mode. As both stationary and moving switch contacts are in close proximity to each other, a sufficiently safe air gap is not maintained, resulting in ionization of air and an arcing fault between the switch contacts. The energy from an arcing fault would result in a sudden build up of pressure in the cubicle that is capable of causing explosive damage to the unit, potentially subjecting anyone in the close vicinity of the switch to serious personal injury.

During a failure investigation of a SCADA-controlled air-insulated pad-mounted switch in 2008, a defective spring within the motor mechanism of the switch unit was identified as the root cause of failure. The spring had broken during the switching operation, resulting in an arcing fault across the contact points of the switch in the switchgear. The unit had subsequently caught fire and was destroyed from the energy of the arcing fault.

Upon further investigation and communication with the switch manufacturer, THESL was informed of a manufacturing defect for air-insulated pad-mounted switches shipped between 2004 and 2008 in which there is a risk that the units may contain defective springs. Although no personnel safety related incident has been reported with operation of this type of equipment, the hidden failure mode of a broken spring could create a potential safety risk to THESL crew workers should any of these defective assets be manually operated. Details of this investigation, along with the subsequent safety bulletin can be found in Appendix D and Appendix E, respectively.

2.5. The Solution

The increasing and accelerated failure rate is linked to the insulation medium breakdown process due to contamination ingress, along with defective springs found in specific units manufactured between 2004 and 2008. The failure modes of these units presents potential serious safety risks to crew workers who operate this equipment and perform routine maintenance procedures, due to the live-front design in which energized components are fully exposed. Efforts to eliminate contamination through carbon-dioxide (CO_2) washing have also been identified as possible contributors to accelerated degradation, due to microscopic damage that can occur to the insulation surface.

Over the past five-year period, an average of 55.2 air-insulated pad-mounted switch failures have taken place per year. Applying this average failure rate against the total population of this asset class, the mean useful life for these assets at THESL can be approximated to 18 years. This is far below the useful life of 30 years reported by Kinectrics. This further supports the fact that these assets are failing at an accelerated pace. Due to the increasing accelerated failure rate of air-insulated pad-mounted switches and the associated negative impact on reliability, customer service and safety, the risk must be mitigated through planned capital replacement jobs on an urgent basis.

THESL proposes that thepreferred option to mitigate these risks is to replace these assets with SF_6-insulated pad-mounted switches. These assets are designed in such a fashion that all electrical components are fully sealed, thus mitigating the risk of electrical flashover and safety risk to personnel performing routing inspection and operation tasks. Due to this design, external contaminants cannot enter into these assets, thus eliminating any chance for contamination. These assets can also be SCADA-enabled, thus allowing for remote operation by power system controllers, along with monitoring of loading and status information. These assets can be further upgraded for use within a Feeder Automation scheme.

IV PREFERRED ALTERNATIVE

1) Direct Buried Cable

THESL considered four options for correcting the problems with direct buried cables.

a) Repair faults – defer replacement capital work
b) Rejuvenate existing XLPE direct buried cables via cable injection
c) Replace existing XLPE direct buried cables with tree-retardant XLPE (TR-XLPE) direct buried cables
d) Replace existing XLPE direct buried cables with tree-retardant XLPE (TR-XLPE) cables in concrete-encased ducts

Option 1: Repair Faults – Defer Replacement Capital Work

In this option, direct-buried cables are repaired each time they fail and only the failed portion of cable is replaced. The process can be summarized as follows:

a) Identify the faulted cable segment (50-100m length) based on visual inspection of the interrupted devices
b) Install fault-locating equipment (thumper) to determine the fault location[3]
c) Dig a splice-pit in the identified location (see Figure 1)
d) If the device erred in the location of the fault, repeat thumping and step 3
e) Cut and remove the faulted section of cable (Figure 2)
f) Install a new section of cable and connect via splices (Figure 3)
g) Back-fill pit

[3]Thumping itself weakens an already aged, stressed cable due to the repeated short-term high-voltage (up to 30kV) DC pulses transmitted to locate the fault, http://www.abb.com/cawp/seitp202/003a314df08e8aedc12578380056f1f3.aspx

Figure 1: Field personnel within a splice-pit preparing to splice a faulted cable to restore service to area. (Taken on February 15, 2011)

Repairing faulted cable is remediation and not a solution to the problem. It does not resolve the underlying issue and risks (related to potential dig-ins), specific to direct buried cables. As well, a repaired cable now faces a twofold problem pertaining to moisture, the first due to hydrothermal aging of the cable (accelerating premature aging) and the second due to the two new splices that have been added [Ref 11 – App A]. Cable splices tend to introduce problems and risks to the distribution system. When water accumulates in a cable splice, it leads to a breakdown in the insulation properties. When insulation breakdown occurs, the conductor begins arcing to ground. The arcing produces an intense heat that causes rapid evaporation of the water, which, in turn, results in a sudden high vapor pressure inside the cable splice. The resulting high pressure vapor extinguishes the arcing. Hence, these faults are classified as self-clearing and will simply show up as auto-reclosure or momentary interruptions on the feeder (thus increasing the momentary average interruption frequency index or MAIFI). Once a splice experiences this momentary fault the frequency of these fault occurrences begin to increase over time. Because these first few arcs have already started to weaken and degrade the insulation at the splice location, the occurrence of arcs will likely increase with time until the splice eventually fails. Depending on the condition of the spliced cable, this type of splice failure could happen within a matter of days [Ref 11 – App A]. Maintaining THESL's system in remediation mode such as this, tends to lead to more frequent and longer outages with the associated escalating repair costs. At some point, the cable is no longer useful, and the entire cable segment will have to be replaced. Trending data collected specifically for MAIFI over the past eight years has shown that, on average, 8% of outages specifically related to direct buried cables are caused by cable splices.

Figure 2: Field personnel within splice-pit, removing faulted cable segment. (Taken on February 15, 2011)

Figure 4 illustrates the difficulties pertaining to restoring power to customers along direct buried cables. In this particular case, the customer had to be awoken in the middle of the night to move their vehicle so that the faulted cable under their driveway could be repaired and power restored.

Figure 3: Field personnel completed splicing the cable. Notice two splices required for each faulted cable segment. (Taken on February 15, 2011)

Figure 4: Disturbance to customer in the middle of the night to repair cables and restore service. (Taken on January 27, 2012)

The process for locating and repairing a failed segment of direct buried cable, described at the beginning of this section, can be quite lengthy. Table 1 lists significant outages over the past ten years that were caused by direct buried cable failures. The table includes the system average interruption duration index (SAIDI) contributions of each of these failures. In some cases, customers were out of power for more than a day.

Table 1: Examples of direct buried cable failures that caused significant outages

Category	Year	Feeder	District	Outage Duration (Hours)	SAIDI Contribution
Longest Duration	2010	ETMGF1	Etobicoke	27.98	0.13
	2004	NYSS68-F7	North York	27.77	0.00
	2010	ETLFF1	Etobicoke	27.68	0.05
	2004	NY55M25	North York	25.38	0.00
	2008	NY80M32	North York	24.10	0.03
Largest SAIDI Contribution	2002	NY51M3	North York	6.42	0.98
	2010	NY51M30	North York	5.02	0.97
	2009	NY55M9	North York	3.20	0.96
	2008	NY85M23	North York	2.27	0.95
	2008	NY85M23	North York	17.20	0.95
	2010	NYSS68-F9	North York	16.97	0.77
	2002	NY53M24	North York	3.95	0.73
	2005	NY51M6	North York	12.32	0.70

Figure 5 provides a closer look at the typical environment in which direct buried cables are exposed over the duration of their service. More images of the difficulties and disruptions associated with direct buried cables are provided in Appendix B.

Figure 5: Typical environment of direct buried cable over its service life–surrounded by rocks and immersed in mud. (Taken on January 27, 2012)

Unfortunately, it would not be practical to convert direct buried cables to cables in concrete-encased conduit during an unplanned outage. During an unplanned outage customers are out of power and need service restored as quickly as possible, so burying cable directly in the ground and splicing is the only feasible solution at the time of the event. Replacing direct buried cables with cables in conduit would require planning and sufficient notice to the customers so that the work could be done within a reasonable time frame and with the minimum amount of inconvenience and damage to customer property.

Option 2: Rejuvenate existing XLPE direct buried cables via cable injection

In 2008, THESL completed a cable rejuvenation pilot job. Direct buried XLPE cable was injected with insulation rejuvenating fluids (such as silicon-based fluids). The pilot job was not as successful as THESL had anticipated. Based upon a qualitative analysis, it was determined that the cable injection process had a number of operational issues and drawbacks, including the need to locate and remove existing splices in cable circuits, the difficulties in accurately locating these splices, and the need for extremely long planned outages required to implement the cable injection procedures. A quantitative analysis was performed, which indicated that a very low percentage of cable assets would receive a positive net benefit from injection. It was concluded that cable injection was not an economically viable alternative to replacement. The detailed study of the cable injection pilot job has been included in Appendix C.

Option 3: Replace XLPE direct buried cables with tree-retardant XLPE (TR-XLPE) direct buried cables

This option has the benefit of a longer service life from the newer technology cable type, however is still susceptible to dig-ins and eventual premature hydrothermal aging and all of the other disadvantages associated with Option 1.

Option 4: Replace XLPE direct buried cables with tree-retardant XLPE (TR-XLPE) direct buried cables in concrete-encased duct

This option includes the newer cable technology with its associated longer service life as well as mechanical protection and the ability to easily replace sections of faulted cable. The length of service interruptions to repair faults is also expected to be minimized compared to the other options.

The advantages and disadvantages of each of the above options are summarized in Table 2.

The advantages of replacing existing direct buried XLPE cable with cable in concrete-encased ducts out-weigh the disadvantage of higher initial cost. Replacing direct buried infrastructure with concrete-encased infrastructure at the end of the first service life cycle would lead to reduced replacement costs in the future.

Table 3 compares costs of Options 1, 2, 3 and 4.

1 **Table 2: Advantages and disadvantages of proposed mitigation options**

Option	Advantages	Disadvantages
1. Repair faults – defer all replacement capital work	• Lower capital spending in the short-term	• Higher overall capital costs (reactive plus near-term replacement) • More failures • Longer service recovery time due to o Difficulty locating faults o Trenching required to repair the cable • Premature hydrothermal aging due to nature of underground environment (deteriorating reliability) • Extremely vulnerable to dig-ins
2. Rejuvenate existing XLPE direct buried cables via cable injection	• Laboratory tests indicate that it prolongs the life of an aged cable for a few years	• Does not eliminate the need to replace the direct buried cables • Higher planned outage costs • Increased planned interruptions to the customer • Cable failures still occur on rejuvenated cable segments • Life is only extended by a few years
3. Replace existing XLPE direct buried cables with new strand-filled TR-XLPE direct buried cables	• Lower *initial* installation cost than option 4. • Longer service life than option 1 and 2.	• Higher replacement costs • Longer service recovery time due to o Difficulty locating faults o Trenching required to change the cable • Premature hydrothermal aging due to nature of underground environment • Extremely vulnerable to dig-ins • Higher risk of failure due to the effects of moisture on the splices • Aged cable further weakened due to the new joints installed
4. Replace existing XLPE direct buried cables with new strand-filled TR-XLPE cables in concrete-encased ducts	• Lowest future cable replacement costs • Reduced safety hazard to the public as now cable is protected from dig-ins • Ducts are protected from collapse due to shifting of the ground and other mechanical stresses • Cable is protected from premature hydrothermal aging • Quicker service recovery times to the customer • More efficient to maintain	• Higher *initial* installation cost due to required civil infrastructure

1 **Table 3: Installation/rejuvenation costs of new 1/0 Al TR-XLPE cable and repair costs due to**
2 **an unplanned outage for a single-phase circuit**

	Installation / Rejuvenation Costs				Repair Due to Outage			
Option	**Material / Injection Cost (per meter)**	**Electrical Labour Cost (per segment)**	**Civil Cost (per metre)**	**Total Installation/ Rejuvenation Cost (1)**	**Electrical Material and Labour Cost**	**Civil Cost**	**Total Costs**	**Total Costs per metre**
1.Performing reactive work on the feeder (i.e. replace XLPE with strand-filled TR-XLPE)	$12.97	$5,376.64	$452.00	$51,873.64	$4,921.93 (2)	$1,244 (per splice-pit) (3)	$6,165.60	$6,165.60
2. Rejuvenate existing XLPE direct buried cables via cable injection	20.01	$3,352.08	$522.50	$57,603.08	$4,921.93 (2)	$1,244 (per splice-pit) (3)	$6,165.60	$6,165.60
3. Replace existing XLPE direct buried cables with new strand-filled TR-XLPE direct buried cables	$12.97	$5,376.64	$452.00	$51,873.64	$4,921.93 (2)	$1,244 (per splice-pit) (3)	$6,165.60	$6,165.60
4. Replace existing XLPE direct buried cables with new strand-filled TR-XLPE cables in concrete-encased ducts	$12.97	$5,376.64	$669.05	$73,578.64	$9,340.44 (4)	N/A	$9,340.44	$93.40

Table Notes

1) The total installation assumes 100m segment and cable length.

2) Each faulted cable will require two splices; this price reflects the cost of two splices plus labour.

3) This is assuming that the fault is located on the first try and only one splice pit is required, otherwise multiple pits may be needed and accounted for in the repair calculations.

4) This price assumes a 100m length of cable between two cable chambers is being replaced since the entire cable run of a ducted cable needs to be replaced after a fault.

From Table 3 it can be seen that the initial capital cost associated with Option 4 is higher than that of Options 1, 2 and 3. Although it appears that the repair costs of Option 4 are higher than those of Option 3, it should be noted that these costs only account for the repair of a single faulted section. Typically, when an aged direct buried cable fails once, other failures will begin to occur on the same segment. Based on field experience, if three or more insulation failures occur on a single cable segment that feeder is flagged as unreliable and a recommendation is made to rebuild the entire area associated with that cable segment.

Here, two recent examples of repeated failures on the same segment of direct buried cable are presented; in both cases the entire cable segment now needs to be replaced. The first example is that of a direct buried segment of feeder NYSS53M7. The 35 meter segment has failed nine times since 2008, with four of the failures occurring in January and February of 2012. Field crews have also reported that the insulation of this cable segment is severely damaged to the point that it is visually noticeable. Thus this feeder has been flagged as one which needs immediate attention.

The second example is the case of feeder SCNAE5-M29. In 2009 a segment of this feeder between two transformer stations was flagged due to poor reliability. Some remediation was performed and the feeder trend started to show signs of improvement therefore the jobs and sub-jobs originally assigned to this feeder were deferred. However, the feeder started to fail again in the fall of 2011 and further remediation actions were taken. This did not improve the reliability of this segment of the feeder. The repeated failures deteriorated the dielectric insulation to the point that recently, when field crews attempted to transfer load in order to upgrade pad-mounted switchgear, the cable segment failed.

Unfortunately this is a common scenario experienced by various utilities in the industry as reported by Jack H. Lawson in his paper, *Utility URD Cable Experience* [Ref 12 – App A]

Using the data in Table 3 it can be seen that the cost of repairing the direct buried cable segment along feeder NYSS53M7 – four times in January and February – carried a cost $24,662.40. Additional costs were incurred to address the previous failures, and further costs will be incurred to reactively replace the entire 35-metre segment. Had this cable segment been concrete encased, after the first fault the entire segment would have been replaced with a new segment for a cost of $9,340.44.

It is therefore fair to conclude that the repair costs associated with direct buried cable failures could be as high as three times that which is indicated in Table 3. Furthermore, the cables in concrete-encased ducts will have their asset life renewed (when they are replaced) and will be able to last longer and provide more reliable service compared to the direct buried cables that are not only weakened due to age, but also due to the added splices during repairs. Hence, among the options discussed, Option 4, proactive replacement of direct buried cable with cable in concrete-encased ducts, is the most prudent option.

2) Air Insulated Pad-mounted Switchgear

THESL considered five options to mitigate the reliability and safety risks associated with this equipment:

a) Accelerated maintenance frequency
b) Reactively replace a failed unit with a similar unit
c) Install a moisture barrier at the base of each switch
d) Reactively replace a failed unit with a Pad-Mounted Enclosed (PME) unit
e) Proactively replace with non air insulated pad-mounted switchgear

Option 1: Accelerated Maintenance Frequency

Air-insulated pad-mounted switches are maintained on an annual basis. Maintenance involves visual inspection and infrared and ultrasonic scanning of the live switchgear unit to determine the presence of excess contamination buildup, hot spots and corona discharge (partial electrical discharge in the air). Corrective work resulting from maintenance activities involves carbon dioxide (CO_2) washing of the energized unit to remove dirt and other contaminants while maintaining power supply to customers. Carbon dioxide (CO_2) washing is a process whereby dry ice pellets are propelled at a high velocity by a compressed air gun. Upon impact, the dry ice creates a micro-thermal shock (caused by the extreme cold temperature of -79º C) that breaks the bond between the insulator coating and the dirt. The high pressure air stream removes contaminants from the surface of the material, while the dry ice pellets vaporize. This corrective action is effective in terms of removing excess dirt build up while maintaining power supply to customers.

However, it is also suspected that the process of micro-thermal shock that separates contaminants from the insulation surface also causes microscopic damage to the insulator itself by removing some of its coating. Over time, the integrity of the insulator may degrade, resulting in a premature failure trend like the one THESL has been experiencing for these assets. While CO_2 washing may negatively impact switchgear components, it is the only corrective cleaning that can be performed without requiring an outage.

While the maintenance and corrective actions may reduce the likelihood of insulation breakdown and subsequent failure, they do not completely eliminate the likelihood of such failure. This is because the switches utilize natural air ventilation and are therefore constantly subject to ingress of airborne dirt and other contaminants through the ventilation louvers. When combined with moisture and condensation that can rapidly build up overnight, tracking and flashovers can occur within a short time period. Consequently, even with a frequent maintenance program, this equipment class is still susceptible to a high failure rate. Not only have maintenance activities been ineffective in reducing the failure rate, it also does not eliminate the potential safety risk associated with air-insulated pad-mounted switches.

Option 2: Reactively Replace with Similar Unit

To replace the failed unit with another unit of the same design would not address the root cause of the failure mode, which is exposure to dirt, contamination and moisture. Also, if the unit is to be replaced only after a failure (i.e., in a reactive mode), in addition to the lengthy power outage, the cost of emergency replacement would be much higher than planned replacement.

Option 3: Install Moisture Barrier

THESL has performed trial installation of a fiber-board barrier at the base of an air-insulated pad-mounted switchgear unit to block ingress of moisture from the concrete foundation below the unit. However, this moisture barrier was not effective as it did not address the true cause of flashovers – the ingress of contamination and moisture into the switch cubicle through the ventilation louvers. The louvers cannot be blocked because the units are naturally vented for cooling. In addition, the fiberboard started to collect water after a period of time.

Option 4: Reactively Replace with PME Unit

PME design refers to Air-Insulated Pad-Mounted Enclosed (PME) switches which feature the same general air-insulated design, but with electrical connections that are made within the unit itself. As a result, this form of design is referred to as “dead-front”, as opposed to the “live-front” design associated with the traditional Air-Insulated Pad-Mounted switches. The design for this asset type, as a result, still features the same ventilating louvers as air-insulated pad-mounted switches, meaning that airborne contaminants can still enter the unit through these louvers. Ultimately, this design will result in the same failure modes as with regular air-insulated pad-mounted switches.

Option 5: Proactively Replace with Non-Air-Insulated Unit

The root cause of failure of air-insulated pad-mounted switches is the existence of air ventilation louvers that allow air borne contaminants and moisture to enter the switch cubicle. To completely eliminate this failure mode, air-insulated pad-mounted switchgear must be replaced with completely sealed, air-tight switchgear that blocks any such elements from entering the live compartment of the switchgear. There are three non-air-insulated pad-mounted switchgear options available:

a) Oil-Insulated
b) Solid Di-electric
c) SF_6-Insulated

Oil-insulated pad-mounted switches have been around for many years, but they have drawbacks that prevent them from being a feasible alternative to air-insulated pad-mounted switches. One of these drawbacks – arguably the most serious drawback – is that the failure of an oil-insulated switch can be catastrophic. It is not uncommon for an oil-insulated switch to explode and result in a fire when it fails, presenting a potential safety risk to personnel and the public.

Solid di-electric distribution switchgear is compact and modular, and presents many advantages. However, at this point, solid di-electric switches available from known manufacturers do not meet THESL's fault rating requirement for 27.6 kV distribution.

With SF_6 (sulfur hexafluoride)-insulated pad-mounted switches, all internal live components are physically encapsulated and sealed from the exterior environment. SF_6 gas is used as the insulation medium. Vacuum bottle switches are used for circuit interruption. Both of these components meet THESL's technical specification for fault interruption at the 27.6 kV level.

The advantage of the SF_6 design is that it fully blocks ingress of contaminants and moisture into the switching compartment. External cables are connected to switch terminals using sealed separable elbow connectors, thus completely eliminating exposure of any live components to moisture and dirt. Consequently, safety for THESL personnel is significantly improved. SF_6-insulated pad-mounted switches have the same circuit configuration as air-insulated pad-mounted switches and can be installed atop the same concrete foundation being used by the existing asset. As all external components are sealed, it is expected to be a maintenance-free asset, saving THESL from costly inspection and CO2 washing expenses.

SF_6-insulated pad-mounted switches utilize resettable fault interrupters instead of actual fuses, making them capable of tripping all three phases in the case of a single-phase fault in order to prevent equipment damage. In addition, these assets can be equipped with micro-processor based controllers for remote operation and monitoring of load, switch status and SF_6 gas levels. This type of asset can be upgraded with the appropriate software in order to operate as part of a Feeder Automation scheme.

Options 1 through 4 do not address the root cause of failure – the design of air-insulated pad-mounted switchgear which allows for contamination and moisture to accumulate on the switching equipment – and do not eliminate the likelihood of air-insulated pad-mounted switchgear failures; failures that carry significant reliability impacts. Option 5, proactive replacement of air-insulated pad-mounted switches with SF_6-insulated pad-mounted switches, is the only one of these options that addresses the failure mode associated with air-insulated pad-mounted switches.

3) Avoided Risk Cost

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

Carrying out work on this asset class immediately instead of deferring to 2015 will result in an estimated avoided risk cost of $230 million. This figure shows that there are substantial economic benefits from executing this work immediately. In addition to the avoided risk cost, approximately 67,500 CI and 60,000 CHI are expected to be mitigated by the time the Underground Infrastructure segment is completed in (compared to a "do-nothing" or "run-to–fail" approach). Further explanation is provided in Appendix F.

V APPENDICES

Appendix A – References

Appendix B – Repair to Direct Buried Cables

Appendix C – Report on Toronto Hydro's Experience in Extending the Service Life of Distribution Cables with Insulation Rejuvenating Fluids

Appendix D – Equipment Failure Report # 2008-5

Appendix E – EHS Bulletin: Pad-mounted Switches

Appendix F – Underground Infrastructure Business Case Evaluation (BCE) Process

APPENDIX A

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APPENDIX B

Repair to Direct Buried Cables

Figure B1: Faulted direct buried cable segment due to insulation failure (taken on February 15, 2011)

Figure B2: Typical environment of direct buried cables (taken on August 5, 2011)

Figure B3: Shearing of PVC ducts due to the natural movement of the earth (taken on July 12, 2011)

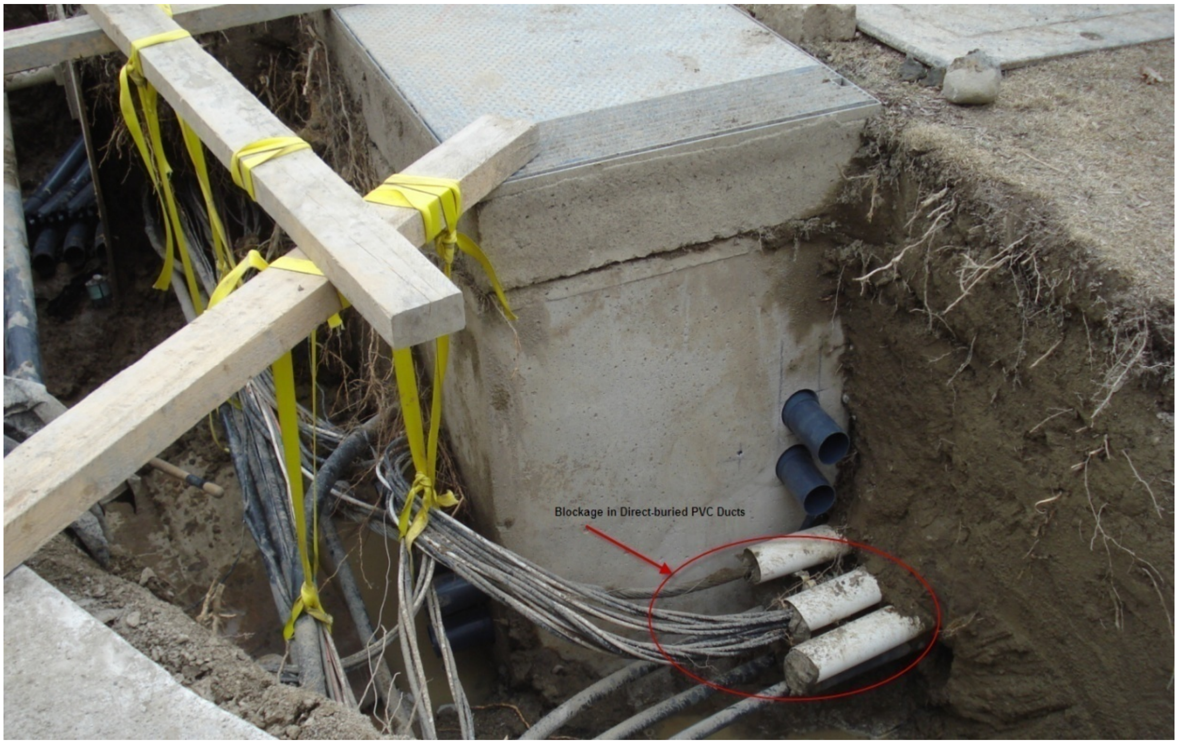
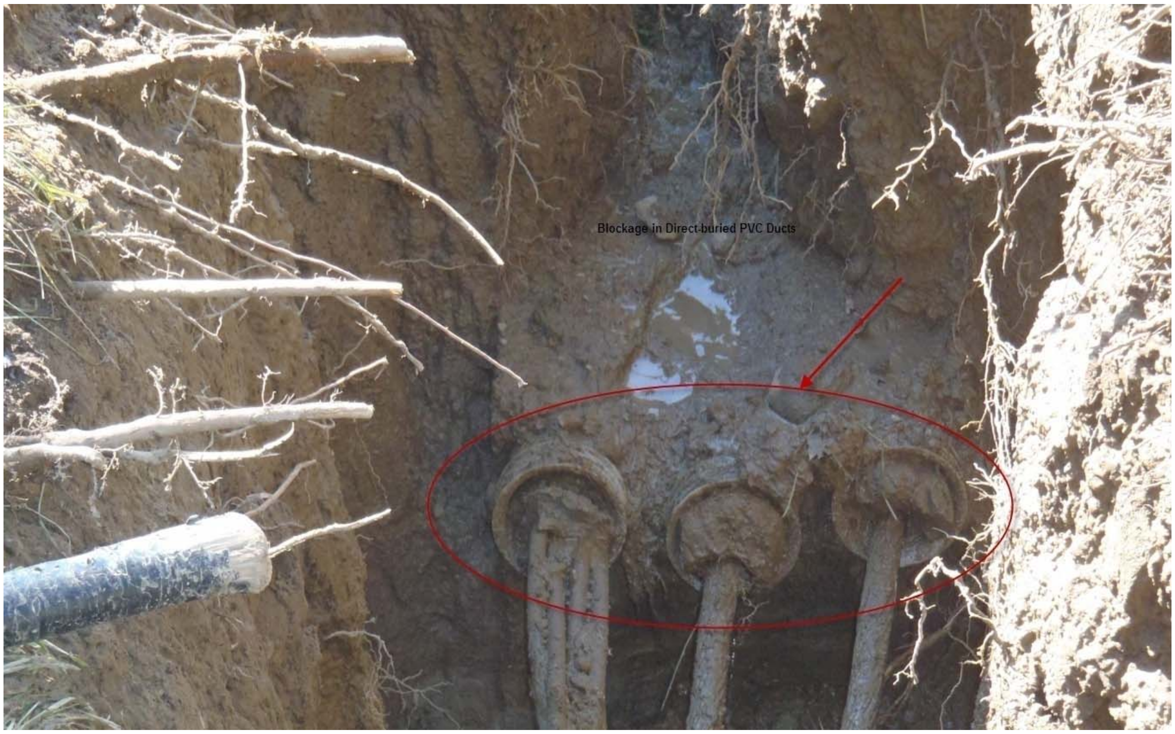


Figure B4: Typical blockage seen within direct buried PVC ducts over time (taken on March 25, 2010)



1 **Figure B5: Close-up of blockage in direct buried PVC ducts (taken on October 5, 2011)**

APPENDIX C

Report on Toronto Hydro's Experience in Extending the Service Life of Distribution Cables with Insulation Rejuvenating Fluids

Toronto Hydro's Experience in Extending the Service Life of Distribution Cables with Insulation Rejuvenating Fluids

Robert Otal

Toronto Hydro-Electric System Limited

Table of Contents

Executive Summary

This paper summarizes the findings of two pilot jobs completed by Toronto Hydro to determine the technical and economic viability of medium voltage XLPE cables' life extension by injecting the cables with insulation rejuvenation fluids. The purpose of the study was to determine if the commercially available insulation rejuvenation products offer a superior solution to replacing underground cables when the risk of their in-service failures approaches unacceptable levels.

Upon completion of the pilot jobs, a comparative study was performed to determine the optimal intervention solution for Toronto Hydro's existing direct-buried, unjacketed, XLPE cable circuits. These assets represent the highest risks to Toronto Hydro, due to their inherently high probability of failure and the excessive length of time required to restore power following cable failures.

Both qualitative and quantitative analysis was performed to evaluate the effectiveness of the cable injection option in relation to the cable replacement. The qualitative analysis closely examined the processes applied for both cable injection and replacement activities including potential operational issues. The quantitative analysis was performed by taking various elements from the replacement and injection process, such as capital costs, planned outage durations required for job implementation and the expected improvements in life following the intervention solution.

THESL calculated the net benefit of each intervention alternative for different cable segments. From this qualitative analysis, it was determined that the cable injection process had a number of operational issues and drawbacks, including the need to locate and remove existing splices in cable circuits, the difficulties in accurately locating these splices, and the need for extremely long planned outages required to implement the cable injection procedures. Although both injection vendors claimed that there would be an extension of life following the injection activities, there were at least three unexplained cable failures within one year of the injection procedure.

Quantitative analysis results varied between the two vendors. With one vendor, it was determined that the planned outage times associated with cable injection alternative were unacceptably high when compared to the expected renewal benefit from the injection procedure. With the second vendor, while these outage times were lower, the expected renewal benefit was also lower, due to expected life extension of 20 years as opposed to 40 years. This resulted in a negative net benefit of injection for the vast majority of cable segments, when compared to performing cable replacement.

Based on the qualitative and quantitative analysis results, we have concluded that for Toronto Hydro’s distribution system, which extensively employs submersible transformers in below ground vaults with low clearances, cable rejuvenation programs commercially available from vendors do not provide an attractive alternative to cable replacement. More research and development by vendors is required, in order to mitigate operational issues, reduce costs and customer outage times and improve the overall cable injection formulations in order to provide guaranteed performance of rejuvenated cables.

I Introduction

This paper assesses the technical and economic feasibility of extending the service life of medium voltage (MV) cables employed on Toronto Hydro's distribution system through injection of cables with insulation rejuvenating fluids.

Toronto Hydro is the local distributor of electricity in the City of Toronto, serving approximately 700,000 residential and commercial customers within its service territory, representing approximately 18.5% of all electricity consumers within the province of Ontario[i]. MV cables are an important asset employed on Toronto Hydro's distribution system for two reasons: (a) they represent a significantly large fraction of the capital investment in fixed assets; and (b) in-service failures of MV cables significantly impact the overall reliability of power supply.

In relation to other assets employed on Toronto Hydro's distribution system, MV cables pose a unique challenge for assessment of their health and condition and to mitigate risks associated with poor health. Because they are installed in either underground ducts or direct buried configurations, visual inspections are not a practical option and it is difficult to perform non-invasive tests to assess their condition. It is even more difficult to implement life extension initiatives on underground MV cables. Up until recently, replacement of cables was the sole intervention applied, when these assets were determined to be at the end of their service life based on the selected assessment criteria.

In its on-going search for cost effective solutions to improve distribution system reliability, Toronto Hydro carried out two pilot jobs in 2008-09 to investigate the costs and benefits associated with extending the service life of MV cables through injection with insulation rejuvenation fluids. This paper summarizes the lessons learnt from these two pilot jobs undertaken by Toronto Hydro and compares the costs and benefits against the traditional approach of cable replacement at the end of their useful service life. A risk-based, cost-driven decision support tool known as the Feeder Investment Model (FIM) was employed to perform economic evaluations under both options to provide quantitative assessment of costs and benefits.

II Distribution Cable Aging Mechanisms and Failure Modes

Approximately 73% of Toronto Hydro's underground distribution system employs Cross-Linked Polyethylene (XLPE) cables, a polymer-based insulation, which was first developed in the late 1960's. The manufacturing processes employed in early vintage XLPE cables did not have sufficiently strict quality controls to (a) keep out the impurities from the insulation system or (b) provide reliable sealing of the insulation system to prevent moisture ingress. The steam curing process employed in the manufacture of early vintage XLPE cables also resulted in moisture being trapped in the insulation system. Due to these manufacturing defects, cable manufactured in the late 1960's and early 1970's have suffered from high rates of premature failure of insulation.

Two key aging mechanisms and failure modes for XLPE cables are related to insulation degradation due to electrical treeing and partial discharge activity. Presence of moisture in the insulation system results in water trees, which under the influence of excessive dielectric stress caused by presence of impurities, result in formation of electrical trees, leading to partial discharge activity. Partial discharge activity further accelerates the aging of polymer insulation resulting in eventual failure of the cable.[ii]

Improved specifications and standards employed in manufacture of cables since 1980's have virtually eliminated these early defects. In 1983, a newer formulation of XLPE cable was introduced; known as Tree-Retardant Cross-Linked Polyethylene (TR-XLPE) insulation[iii]. TR-XLPE Cables use super-smooth, extra clean materials and employ triple extruded, dry cure processes reducing the presence of impurities and moisture in cable insulation. Use of a Polyvinyl chloride (PVC) or Polyethylene (PE) jacket further reduces the incidents of moisture ingress.

It takes significantly longer time, work-effort and cost to repair faulted cables, installed in direct buried configurations. When a failure occurs in case of direct-buried cable, the only short-term intervention available is to locate where the failure occurred, excavate the faulted cable area, remove the faulted section and install a repair splice at that location. On the other hand, when faults occur on cables installed in ducts, the faulted cables can be replaced more conveniently and the power can be restored with greater speed and at lower cost. Therefore the consequences of the risk of cable failures are much more severe in the case of direct buried cables in relation to the cables installed in conduit/manhole systems.

Within Toronto Hydro's distribution system, Unjacketed Direct-Buried XLPE cables pose the greatest risk of premature in-service failures. These cables do not employ TR-XLPE insulation and suffer from a higher probability of failure. Resulting outages on these cables result in a longer restoration time in relation to cables in conduit installations. Even after the repairs have been completed, a greater probability of future failure remains, as the splicing procedure provides relief the localized failure but does not fully resolve the insulation degradation on the remainder of the circuit.

III Proactive Risk Mitigation for Distribution Cables

While there are no practical options for on-going monitoring of health and condition of MV cables in real time, there are a number of tests available that allow assessment of the health of cable insulation to proactively mitigate the risks of in-service failures. These tests can be performed on either energized or de-energized cable circuits. IEEE Standard 400-2001 identifies six field tests to assess the health of MV insulated in two distinct test categories: (a) withstand testing and (b) condition assessment testing.

3.1 Withstand Testing

Withstand tests provide the utility with a binary answer of "go" or "no-go", with no trending or numerical results produced. Tests that fall under this category include Direct Current (DC) High Potential Testing (Hipot Test) and Very Low Frequency Testing (VLF Test). These tests involve subjecting the cable insulation to a worst-case scenario in form of an overvoltage, to determine if it will survive. If the cable survives this test, the insulation is considered to be in adequate condition. These tests do not provide quantified means of determining the overall health of the cable, nor do they provide an accurate prediction as to when the cable is expected to fail. All withstand tests require that the cable be isolated and de-energized, before the tests can be performed.

Direct Current High Potential Testing (DC Hipot Test) is the traditional approach for performing condition assessments on distribution cables. These tests were historically performed on Paper-Insulated Lead Covered (PILC) cables, as well as their successors; the Cross-Linked Polyethylene (XLPE) cables. These tests are commonly used as quality control tests during manufacturing, before the cable is installed in service, and also once the cable has been installed in the field[6]. A number of recent studies show that the DC Hipot tests can damage the test specimen or weaken the insulation, causing the cables to fail prematurely following the test. Two studies published by the Electric Power Research Institute (EPRI) concluded that these tests reduce the life of the tested cable in the field and increase the growth of water trees. On the other hand, it was also concluded that the DC Hipot test does not negatively impact newly manufactured cables that are yet to be installed; in other words, these tests may still be a useful factory test during cable manufacturing[6].

Very Low Frequency (VLF) Testing is another form of withstand testing. VLF tests can also cause damage to the tested cable, however due to the relatively lower energy level employed in testing, the extent of such damage will be less severe when compared to the DC Hipot test.

3.2 Condition Assessment Testing

Condition Assessment tests differ from Withstand Tests in that these tests can be performed without the need to take the cable out of service. These tests can also provide a more accurate indication of the health of cable insulation. While typical withstand tests can harm cable insulation, condition assessment tests offer non-destructive approaches to measure the insulation characteristics. Data generated from these tests can be used for trend analysis to determine the full extent of the insulation deterioration[6] and to quantify Hazard Rate Distribution Functions (HDF) for all cables in the system. Two common techniques employed for condition assessment testing include Partial Discharge (PD) and Dissipation Factor (DF/PF) tests.

Partial Discharge (PD) tests allow for the detection and measurement of partial discharge within the insulating medium. Manufacturing defects within the insulation, as well as deterioration that has occurred while the cable has been in service can both be determined from the PD testing. Problem areas along the cable, at splices or terminations can also be identified as per this approach[5]. PD testing may be performed both online, while the cable is still energized, and also offline, with the cable being de-energized and isolated.

Dissipation Factor (DF/PF) tests apply an AC voltage to the insulation medium in order to measure the Power Factor and Dissipation Factor. Power Factor (PF) is the ratio between the resistive current to the total current. Dissipation Factor (DF) is the ratio between resistive current and reactive current[6]. A brand new cable will yield no resistive current during this test, resulting in a near-zero Power Factor. With degradation of insulation, the Dissipation Factor test will reveal an increase in resistive current, thus resulting in an increase in both the Power Factor and Dissipation Factor[5]. This form of testing, unlike PD testing, requires that cables are isolated and de-energized.

By applying only PD testing, the utility may not be able to capture a completely accurate picture with regards to the health of a given cable. For example, PD testing cannot identify the presence of water treeing, before they have developed into electrical trees. A PD test may be performed on a cable with substantial water treeing, with favorable, low probability of failure results being reported. Following this test, electrical treeing can very rapidly develop and spread within the cable, leading to its eventual failure. This is why most experts recommend Partial Discharge testing to be performed in combination with Dissipation Factor testing to provide a more accurate Probability of Failure assessment can be determined.

3.3 Practicality of Testing

As indicated above in Section 3.2, condition assessment testing offers an improved and accurate picture with respect to the health of cable insulation and probability of failure, as opposed to the withstand tests which only provide discreet results, and can cause damage to cable insulation. On-line Partial Discharge (PD) testing is the most attractive technique, because the cable can remain energized while the test is being performed, thus eliminating the need for planned interruptions to the customer. As indicated in Section 3.2, Partial Discharge testing should be performed in combination with Dissipation Factor tests where possible to ensure an accurate Probability of Failure assessment.

Due to the large population of underground cables employed on Toronto Hydro's distribution system, it is not practical to apply these risk mitigation tests on a system-wide basis. The best option is to apply a combination of Partial Discharge (PD) and Dissipation Factor (DF/PF) tests on key cables in varying locations across the system, and use the test results to establish trends in insulation aging and development of Hazard Rate Distribution Functions (HDF). Hazard Rate functions are then employed as part of the risk analysis within the Feeder Investment Model (FIM), in order to calculate the Probability of Failure for a given section of cable.

IV Intervention Options for Distribution Cables

Once it has been identified that risk of failure associated with certain cable circuits has reached an unacceptable level, there are two key intervention options available for implementation. Cable replacement has been the typical intervention option performed up until recently. Two pilot jobs on rejuvenation of the cable, via injection techniques, have been recently completed by Toronto Hydro to ascertain the technical and economic viability of this option as an alternative intervention strategy.

4.1 Cable Replacement and Splicing

The traditional approach for cable intervention is to replace the cable outright once a circuit is determined to have reached the end of its useful life. When a cable is already installed in conduit, the utility can access both ends of the defective cable section from the applicable pulling chambers, remove this cable and replace it with a new section accordingly. Because this typically results in a large section of cable being removed, this will remove the majority, if not all of the degraded cable section. As explained in Section 2, because these cables are installed in conduit, they can be easily replaced without the need for excavation. Therefore the outage duration time is significantly reduced.

For direct buried cables, both short-term and long-term interventions are employed. The immediate short term intervention, as explained in Section 2, is to install a splice replacing the faulted section. This typically involves excavating the location where the fault took place, removing the specific section of faulted cable, and replacing this section with a corresponding splice. This short term solution must be executed as an emergency repair measure for direct buried cables when a cable fault occurs, in order to restore service to the customer in a timely manner. This is more of a “band-aid” solution, as it does not provide a full resolution to the problem. Because the removed cross-section of cable is so small, there is no guarantee that the degradation associated with the cable fault has been completely removed. Water and electrical trees can easily cascade to other adjacent sections of the cable. The only way to truly eliminate the problem is to replace the entire cable section outright.

Toronto Hydro's policy for direct buried cable replacement is to install new concrete-encased conduit and then install new cable within this conduit. By doing so, Toronto Hydro is optimizing their replacement approach by ensuring that any future outages will result in a reduced response time, and an immediate and full replacement of the cable section. Due to the required timeframe, excavation and costs required to install these conduits, this long term intervention is not always carried out following emergency repairs.

When cable replacement is carried out for direct-buried cables, typically a planned outage of mean duration of four hours is required. This planned outage includes the time required to perform excavation activities, disconnection and abandonment of existing direct buried cable, installation of new civil infrastructure and cables. For the purposes of this evaluation, the capital costs associated with cable replacement are provided in Figure 1.

Cable Type	Material Cost (per meter)	Labour Cost (per replacement)	Civil Cost (per meter)
1/0 STR AL XLPE 1-PH	$10.42	$3,352.00	$522.50
1/0 STR AL XLPE 3-PH	$31.26	$5,572.00	$522.50

Figure 1 – Cable Replacement Costs

4.2 Cable Injection

Dow Corning first invented a cable rejuvenation technology known as CableCURE in the late 1980's. This technology is based in injecting an in-service cable with a silicon-based fluid. This fluid propagates into the insulation material, populates any voids in the insulation and eliminates water trees[iv]. Following the injection process, the cable is expected to be rejuvenated with a mean increase in life expectancy of 20 years. Today, Dow Corning has licensed this technology exclusively to UtilX Corporation.

A second cable injection vendor, Novinium, was established in 2003, by many of the same individuals who were involved in the development of the Dow Corning product. Their formulations have improved upon the original silicon-based fluids, and they claim the rejuvenation extends the service life of cables by 40 years.

The potential advantages of cable injection apply mostly to direct buried cables. As explained in Section 4.1, direct buried cables must be replaced with new cables installed in conduit, thus making the intervention process very costly and time consuming. By performing cable injection as opposed to full replacement, the direct buried cable can be kept in the ground with a theoretical rejuvenated life of up to 40 years with the Novinium vendor. In theory, cable injection should offer an improved performance to the cable at a reduced cost, while reducing potential outages to the customer.

In 2008, Toronto Hydro began working with two vendors to execute cable injection activities for a specific set of cables supplied from two different feeders. The following sub-sections explain in further detail the injection processes offered by these two vendors:

4.2.1 Novinium

Novinium was the first vendor contracted by Toronto Hydro to execute a series of cable injection activities. Their injection process is as follows:

(a) A high pressure injection process is applied, which requires for all splices to be removed from the selected cable section.

(b) A series of Time Domain Reflection (TDR) traces are performed to identify the location of splices. These traces are performed by sending a signal down the cable and producing a corresponding graph. If a spike is identified in the graph, this indicates the presence of the splice. The distance of the splice as marked on the graph is used to determine its relative distance on ground. TDR tracing also identifies any neutral corrosion on the circuit. If neutral corrosion is identified on a circuit, the cable circuit is not considered to be a good candidate for injection. Cables must be de-energized while this process is performed.

(c) Injectable compression lugs are installed on both ends of the cable segment (at the transformer elbow). The lugs contain holes to permit drainage of the injection fluid. To install these compression lugs, the cables must be disconnected from the transformer. The transformers must be de-energized during this installation process, due to the limited clearances available within a typical submersible transformer vault, as shown in Figure 10.

(d) If no splices are found, injection is performed from the compression lug to the other end of the cable, as shown in Figure 2.

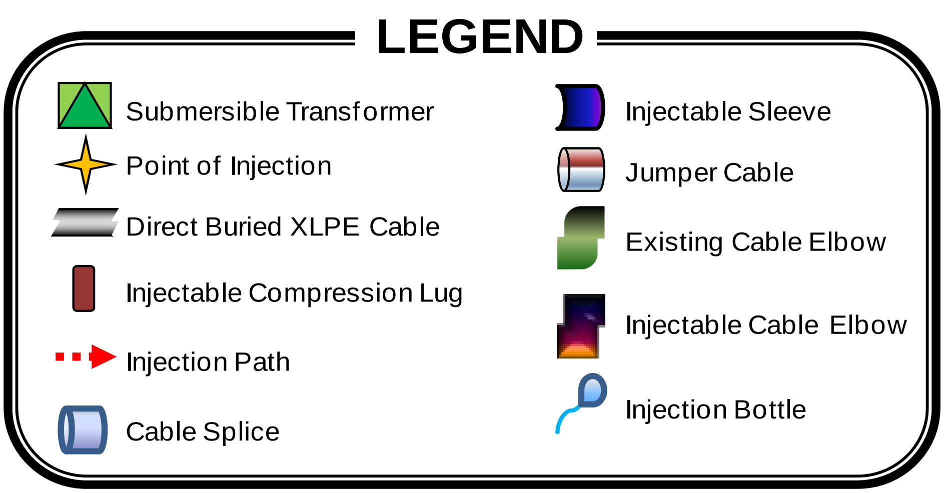
(e) If splices are found, they must be removed accordingly. Injectable sleeves are installed on both ends of the cable where the splice was originally installed. Injection is performed from the respective injectable sleeve to the compression lug. This process is illustrated in Figures 3 and 4.

(f) While injection is performed, equipment must remain de-energized, as employees must remain at both ends of the injection site to ensure that fluid continues to flow, and that no additional blockages are found within the cable.

(g) Following completion of the injection process, the incision holes in the compression lugs are plugged and new splices are installed. Because the splice removal procedure also removed a portion of the original conductor, a jumper cable must be installed to bridge the gap across the original splice location. A new splice must be installed on both sides of this jumper cable. This is illustrated in Figure 5.

(h) In total, an 18 hour planned outage is required on average to each customer supplied from the injected circuit. This outage includes all of the above activities.

(i) Total cost of injection for this Cable Injection Pilot Job process applied to Toronto Hydro's direct buried cables came out to $73 per meter. This cost includes materials and labour costs associated with the TDR tracing, excavation and removal of splices, cable injection, installation of new splices, accessories and components.



Please refer to the above Legend for Figures 2 through to 9

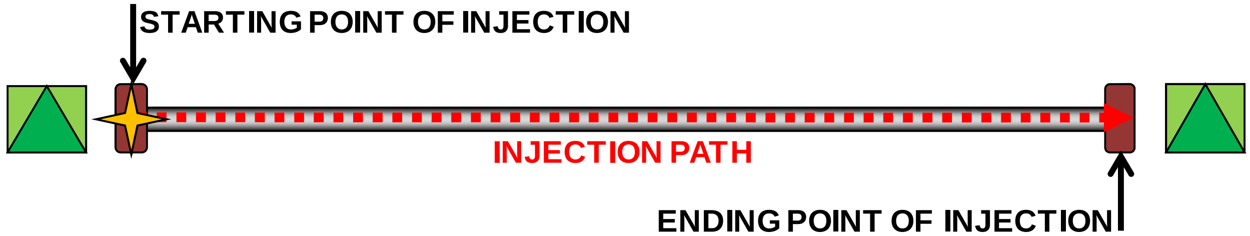


Figure 2 – Injection Process with No Splices (Novinium)

Figure 3 – Cable Configuration with Splice, Prior to Injection Procedure (Novinium)

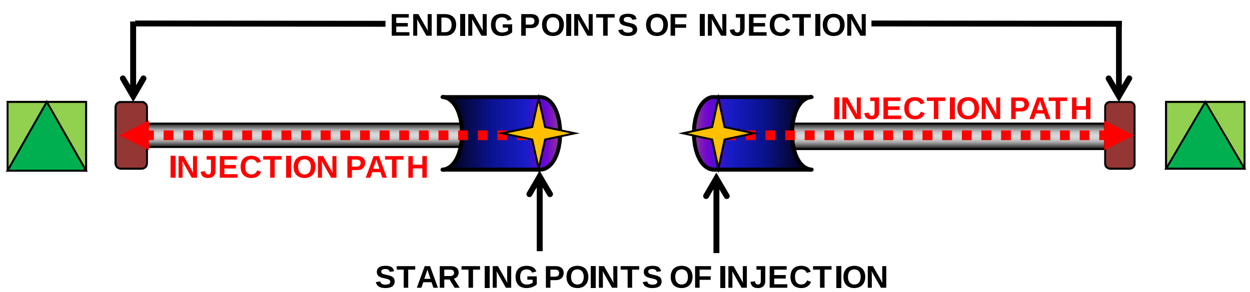


Figure 4 – Removal of Existing Splice, Installation of Injectable Sleeves & Injection Process (Novinium)

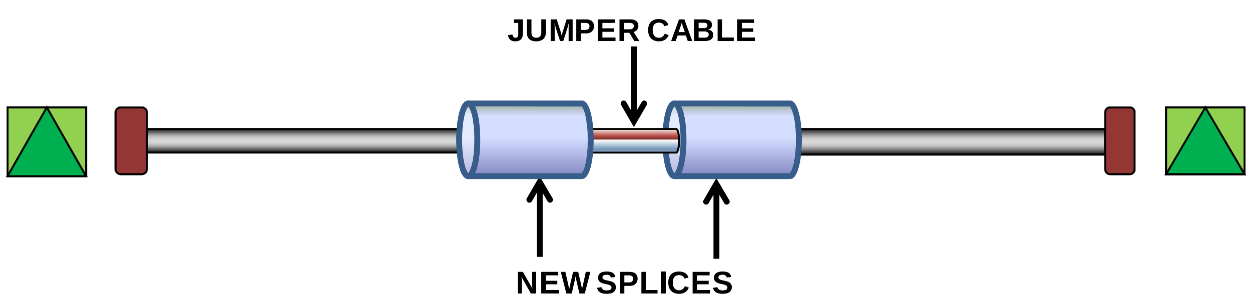


Figure 5 – Installation of New Splices & Jumper Cable (Novinium)

4.2.2 Transelec (CableCURE)

Transelec was the second cable injection vendor contracted by Toronto Hydro. Unlike Novinium, who executes cable injection activities directly, UtilX licenses the CableCURE technology to other vendors. Transelec is the exclusive vendor in Canada to execute the CableCURE injection process. Their process is as follows:

(a) Transelec applies a low pressure injection process. In theory, this means that the injection fluid can travel through splices. The installed splices, however, must support air flow, to allow the injection fluid to pass through.

(b) All transformer elbows between the selected cables are replaced with injectable elbows. Injection bottles are installed at one end of the cable segment. TDR traces and air-flow tests are executed at the same time, as part of a single outage.

(c) If no splices are found, injection is performed from the injectable elbow on one end to the other end of the cable. The fluid will pass from the elbow into the injection bottle, as shown in Figure 6.

(d) If any identified splices fail the air-flow test, these splices must be replaced prior to the injection procedure with new splices which support air flow. Because the splice removal procedure also removed a portion of the original conductor, a jumper cable must be installed to bridge the gap across the original splice location. This jumper cable must be non-tree-retardant/non-strand-blocked such that it will support cable injection. Air-flow supporting splices will be installed on both sides of the jumper cable. This process is shown in Figures 7 and 8.

(e) Once all applicable injection equipment and splices are installed, distribution assets are re-energized.

(f) Cable injection is executed at one end of the cable segment, at the transformer elbow. Due to the nature of this low pressure process, the assets do not require monitoring as the injection fluid is flowing through the cable. Therefore, this Injection process takes place while assets are energized. Injection fluid passes through cable and into bottle at other end. This process is illustrated in Figure 9.

(g) Average time for planned outage using Transelec approach is as follows:

- Single Phase customers: Planned outage lasted total of six hours for each customer.

- Three Phase customers: Planned outage lasted total of five hours for each customer. Outage time was reduced, due to availability of solid-blade disconnect switches connected to the three-phase transformers. Therefore, customers could be restored in shorter time by using the available switches.

(h) Note that with both injection vendors, the injection cost is set to $83 per meter of cable. This cost accounts for the total materials and labour costs associated with cable injection activities.

(i) Total cost of injection for this Cable Injection Pilot Job process applied to Toronto Hydro's direct buried cables came out to $83 per meter. This cost includes materials and labour costs associated with the TDR tracing, excavation and removal of splices, cable injection, installation of new splices, accessories and components.

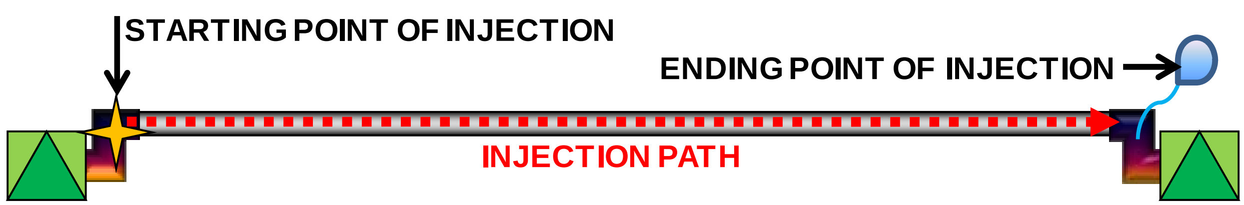


Figure 6 – Injection Process with No Splices (Transelec)

Figure 7 – Cable Configuration with Splice, Prior to Injection Procedure (Transelec)

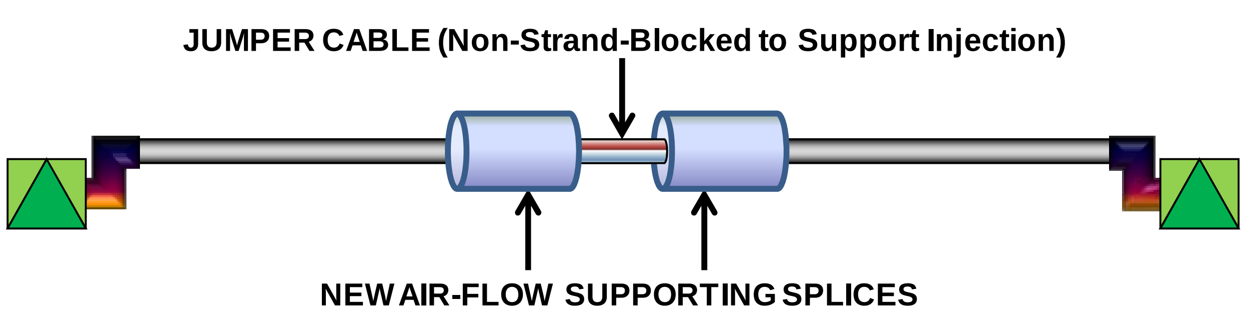


Figure 8 – Installation of Air-Flow Supporting Splices & Non-Strand-Blocked Jumper Cable (Transelec)

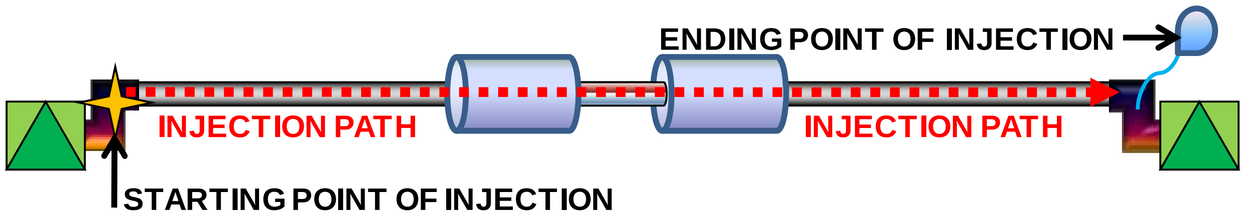


Figure 9 – Injection of Cable from Injectable Elbow to Injection Bottle (Transelec)

V Comparison of Intervention Solutions

A comparative study was performed to determine the most optimal intervention solution for Toronto Hydro. Both a qualitative and quantitative analysis was performed for cable replacement and injection. Data from a recent pilot study was used to support the cable injection analysis. The quantitative analysis involves the use of the Feeder Investment Model (FIM), which employs a risk-based approach rooted in value-based reliability planning to perform an economic analysis for both solutions.

5.1 Qualitative Assessment of Cable Injection Activities

The advantages and disadvantages for cable replacement activities have already been highlighted in Section 4.1. With respect to cable injection activities, the qualitative assessment varied between the two cable injection vendors.

5.1.1 Novinium

A total circuit length of 8,137 m was injected under this pilot job, out of which 2763 m was three phase circuit. The circuit supplied a total of 45 single phase submersible distribution transformers and one three phase building vault transformer. As per the Novinium process, all identified splices within a direct buried cable span were removed prior to injection activities taking place. Novinium was responsible for executing the TDR tests and marking down the locations for the splices. However, there were numerous cases where a location was excavated and no splices were found. These unnecessary excavations resulted in a higher job cost and more outages to the customer.

The Novinium process did not permit for cables to remain connected to their respective transformers during injection; the cables (elbows) had to be disconnected in order to install injectable compression lugs on both ends. Due to the reduced clearances within the submersible transformer vaults, the transformers were de-energized such that this disconnection procedure could be safely performed. A typical submersible vault is shown in Figure 10. If the connected transformers were pad-mounted, and the respective elbow connections were above-grade, then there would be no need to de-energize the transformer equipment and customers would remain connected during the injection process. However, in case of Toronto Hydro, all of the highest risk cables are supplying submersible transformers installed below-grade in vaults, which require a customer shutdown during rejuvenation of the cables.

As per the Novinium process, the injection of fluids into the cable was approximately three hours long on average. This time duration could vary substantially from one location to another, from as little as one hour for 80 meters of cable, to as high as ten hours for 136 meters of cable. Under certain situations where the injection activities could not be completed in a single day, certain transformers would need to be de-energized twice, subjecting the connected customers to a second outage. In total, 33 planned outages were carried out as per the Novinium injection process.

Due to the de-energizing of the equipment during the injection process, there were situations where the crew was forced to wait until the injection process was completed. Due to lack of visible work performed during this time, this presented a poor perception of the utility staff to customers who noted the staff standing by without doing any work, while the power was out.

Each customer ultimately experienced a mean outage time of 18 hours, during which activities highlighted in Section 4.2.1 were performed. As part of this outage time, switchable transformers were installed at available open points.

Figure 10 – Typical Submersible Transformer Vault

5.1.2 Transelec

A total circuit length of 6,658 m was injected under this pilot job, out of which 3860.5 m was three phase circuit. The circuit also supplied a total of 30 single phase submersible distribution transformers, and 5 three phase building vault transformers.

Transelec applied a low pressure injection procedure, as opposed to the high pressure procedure offered by Novinium. Therefore, splices that supported air-flow could be injected without the need of a planned outage. Like the Novinium process, there were still problems with the Transelec vendor with respect to identifying and locating splices in the cable. In Toronto Hydro's case, none of the installed splices supported air-flow, and therefore had to be removed. Splices were removed and replaced with air-flow supported splices. However, the customer outage was reduced, due to the ability of restoring power following the transfer of supply via the transformer elbows. This process was even quicker with three-phase transformers, where available switches allowed a quick transfer of power.

Both the Novinium and Transelec processes required two splices to be installed at the former splice location, since a portion of the original conductor was removed as part of the splice removal procedure. A jumper cable was installed, in order to bridge the gap within the former splice location. With respect to the Novinium procedure, any jumper cable could be installed since this was performed following the injection procedure.

As part of the Transelec procedure, this jumper cable had to be installed prior to cable injection. For the injection fluids to pass through the cable, this jumper cable had to be non-tree-retardant/non-strand blocked, which posed a problem for Toronto Hydro, since all new cables ordered by the utility were tree-retardant and strand-blocked. Therefore, a special non-strand-blocked cable had to be ordered by Transelec such that the injection could be performed. In this manner, the Novinium process had a key advantage by performing splice replacement after injection activities were complete.

As indicated in Section 4.2.2, the actual injection process took place while the equipment was energized, thus resulting in a greatly reduced outage time when compared to the Novinium process. The planned outage was reduced to six hours on average for single-phase customers, and five hours on average for three-phase customers.

Although splice replacement did not incur an outage to the customer, due to the switching activities taking place, the activities still took a long time to perform by the utility, such that the overall injection activities could not be completed on time. Unlike Novinium, which completed all injection activities as scheduled, Transelec was unable to complete all activities within the allotted timeframe.

Overall, there were a number of limitations as to which cables could be injected for both Novinium and Transelec. Neither vendor could inject cables with corroded neutrals, for example. Transelec, however, appeared to have greater difficulty being able to inject all of their selected cables. Because Novinium injected cables around the removed splice area, this added an additional flexibility with their procedure.

The Transelec procedure presented serious problems when cables were unable to pass air-flow tests, even following the replacement of splices. In one situation, significant time, effort and costs were spent to properly prepare a cable for injection, including excavation of splice locations, replacement of splices and cable terminations. Following the replacement of identified splices, the cable was still unable to pass the air-flow testing, and the remaining splices could not be located. The cable was ultimately not injected, and is currently in the process of being replaced as part of a separate capital job.

As a result of these pilot jobs, Toronto Hydro had anticipated the full renewal in life expectancy for the injected cables, with no further cable failures within the pilot job locations. However, at least three unexplained failures took place within one year of these two pilot jobs. These failures may have taken place due to a variety of reasons.

5.2 Quantitative Assessment of Cable Injection Activities

5.2.1 Quantitative Methodology

The quantitative assessment for Cable Injection was performed with help of Toronto Hydro's Feeder Investment Model (FIM) decision-support tool, which was developed with the assistance of BIS Consulting LLC. The FIM applies a risk-based approach rooted in value-based reliability planning. FIM was used to perform an economic evaluation between cable injection and cable replacement activities, to determine which solution provides improved benefit/cost ratio to Toronto Hydro.

The FIM calculates an assets' risk, by accounting for the Probability and Impact of Asset Failure. To determine the probability of failure, the FIM relies upon the assets' Hazard Rate Distribution Function (HDF). The Hazard Rate represents a conditional probability of asset failure from the remaining population that has survived up to that time. Typically, the Hazard Rate is calculated by examining the historical failure data for a given asset class, and establishing the Probability

Density Function (PDF) from this data. PDF can also be derived from the health and condition of an asset, i.e., results of Partial Discharge (PD) and Dissipation Factor testing and relating the health index of cables to probability of failure as described in Section 3.2.

PDF indicates the percentage of probable failures at any given asset age. The Cumulative Distribution Function (CDF) is then calculated by performing a running sum of these failures across the lifespan of the asset population. The Survival Rate, shown in Equation 1, represents the number of assets that have survived up to a given age out of the total sample size. Finally, the Hazard Rate is computed as per Equation 2. Note that the Hazard Rate represents the average failure probability for that given asset class, at a given age. The overall process for Hazard Rate curve generation is provided in Figure 11.

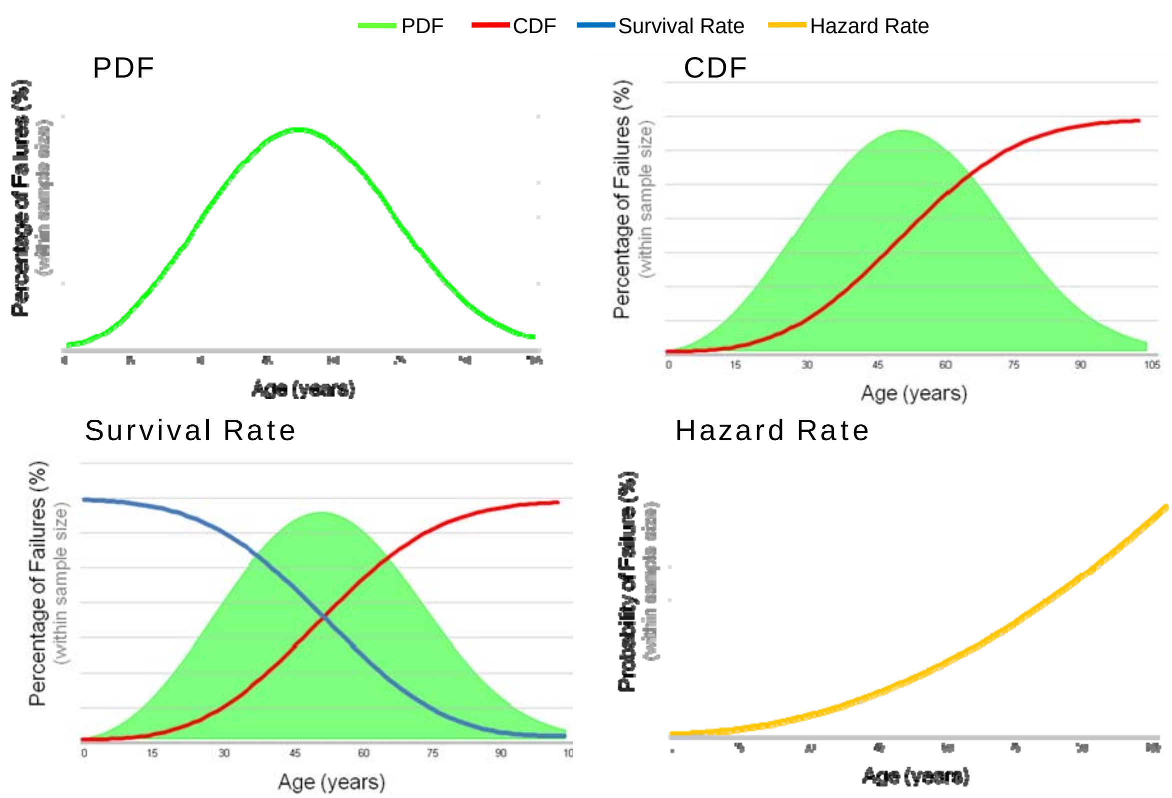


Figure 11 – Hazard Rate Calculation

$$Survival\ Rate = 1 - CDF \quad \text{(Equation 1)}$$

$$Hazard\ Rate\,(HDF) = \frac{PDF}{Survival\ Rate} \quad \text{(Equation 2)}$$

The Feeder Investment Model (FIM) quantifies the Impact of failure into a cost, by considering both the Direct Tangible Costs to the utility as well as the Customer Interruption Costs (CICs). The Direct Tangible Costs represent the materials and labour costs associated with replacing these assets upon their failure in the worst case scenarios. The Customer Interruption Cost (CIC) represents a measure of the monetary losses experienced by the customer due to an outage event. These costs account for the direct and indirect impacts to the customer, including loss of productivity, loss in customer profits, damages to sensitive electronics and appliances, spoilage of food and loss of leisure time.

The Impact Cost represents total of the Direct Tangible Cost and Customer Interruption Cost. The final Risk Cost is computed by multiplying the Hazard Rate curve for each asset with its corresponding Impact Cost.

As part of the final economic evaluation, Life cycle cost analysis is performed to determine the optimal intervention solution for each cable asset. Once the optimal intervention solution has been determined, the FIM also determines the optimal timing to execute this solution. The life cycle cost of the asset is calculated as per Equation 3:

$$LIFE_{CYCLE\,COST} = \sum RISK_{COST} + \sum CAPITAL_{COST} \quad \text{(Equation 3)}$$

Where:

$\sum RISK_{COST}$ = annualized risk cost of the asset.

$\sum CAPITAL_{COST}$ = annualized capital cost of the asset.

$LIFE\_CYCLE_{COST}$ = total operating cost of the asset across it's' life cycle.

The computed Life Cycle Cost, displayed graphically in Figure 12, represents the total operating cost of the asset, taking into account the annualized risk and the capital during its entire life cycle. The optimal time to intervene upon the asset is when these operating costs are at their lowest, as shown by the Equivalent Annualized Cost (EAC) value; the red marker on the Life Cycle Cost curve, for the New Asset in Figure 12.

If replacement is selected as the optimal intervention strategy, the FIM will account for the fact that the existing asset to be replaced (unjacketed, Non-TR XLPE direct buried cable) and the new asset to go into service (jacketed, TR-XLPE cable-in-conduit) have different risk properties. As a result, the EAC from the Life Cycle Cost curve of the New Asset must be cross-referenced with the Risk Cost curve of the Existing Asset, in order to determine the Optimal Timing of Replacement for the existing asset, as indicated by the green marker on the existing assets' risk cost curve in Figure 13. It is at this specific point in time that the existing asset has reached its' economic end-of-life criteria. As per the example in Figure 13, the Optimal Intervention Time for the existing asset is at approximately 47 years of age.

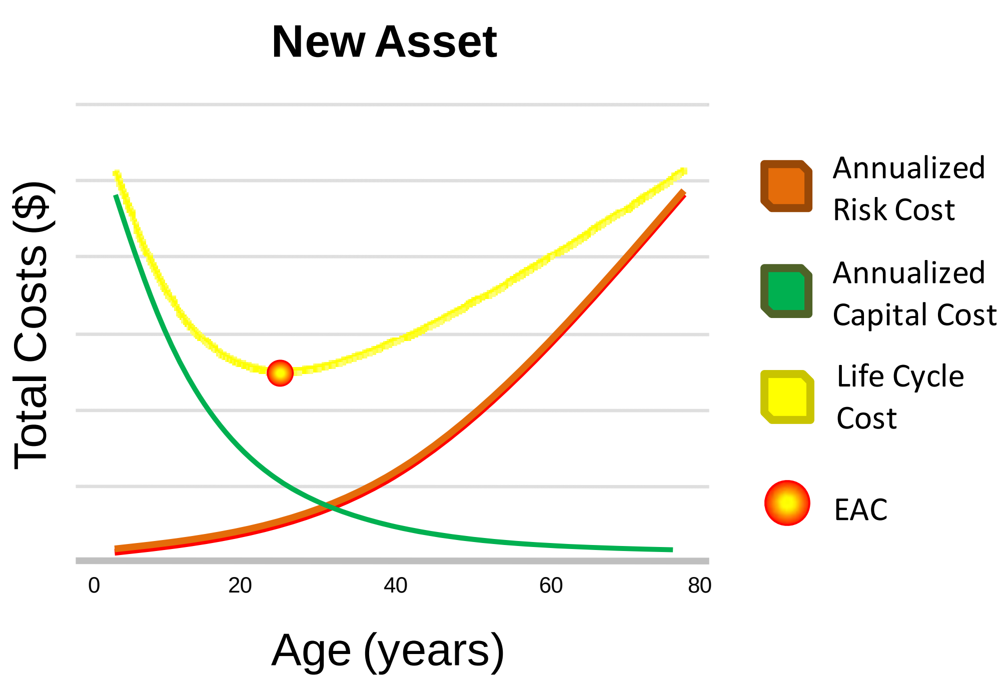


Figure 12 – Life Cycle Cost Analysis for the New Asset

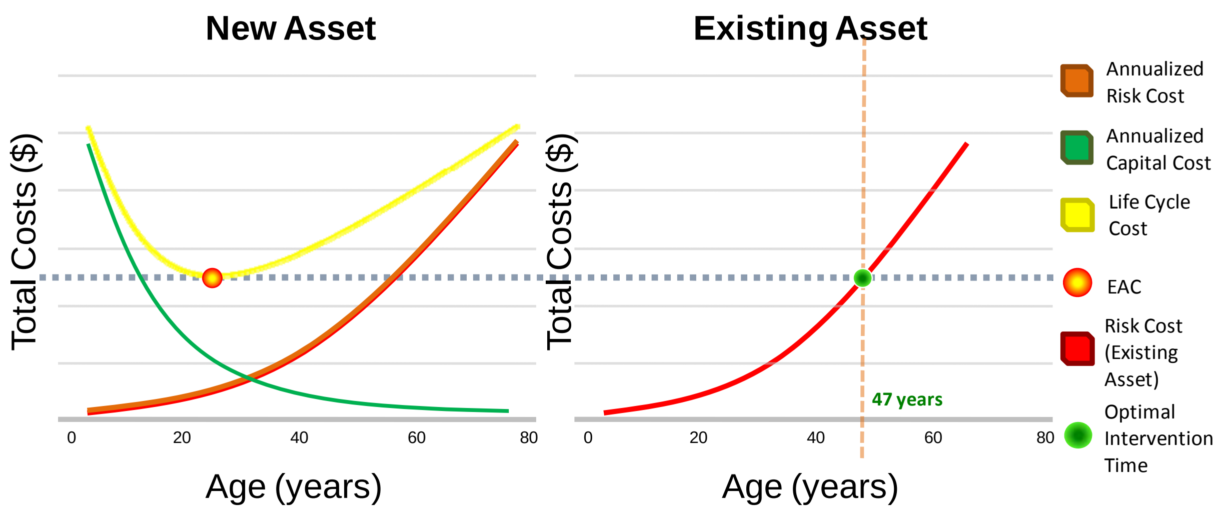


Figure 13 – Optimal Intervention Time of the Existing Asset

To establish the optimal intervention solution between cable replacement and injection, the FIM first solves for the Net Benefit of Injection. This is calculated by examining the Risk Cost curve for the existing asset and comparing this with the deviated Risk Cost curve for the injected asset. As per Figure 14, the injected asset will receive a life extension of 20 years (40 years with the Novinium process). Therefore, there will be an adjustment to the Risk Cost curve, due to the reduction in failure probability and risk, which is represented by the shaded area in Figure 14, also known as the Benefit of Injection. By determining the net present value of this benefit, and subtracting this with the total cost of injection, the Net Benefit of Injection can be determined. If this net benefit is positive, then cable injection is the optimal intervention solution to be carried out as opposed to replacement.

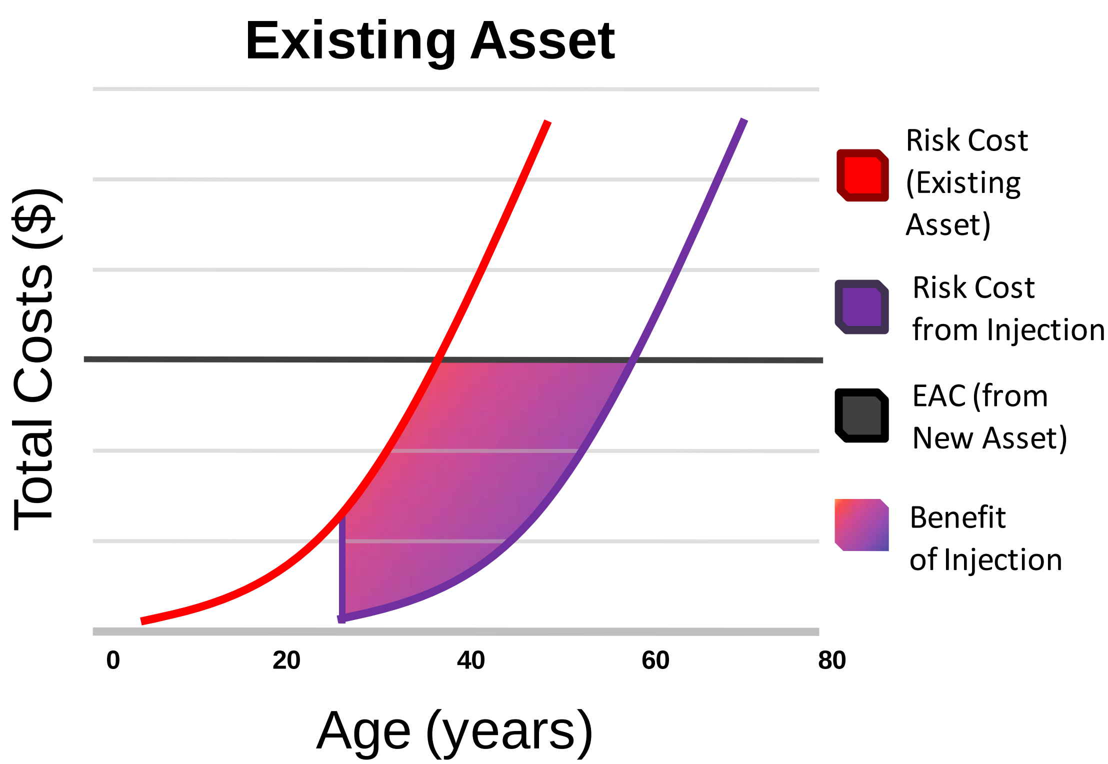


Figure 14 – Net Benefit of Cable Injection

This Net Benefit value is calculated across the life cycle of the asset. As shown in Equation 4, the maximum Net Benefit of Injection value (NB_{INJECT}) will be selected from time 0 to the Optimal Replacement Timing (ORT) of the cable asset. Points along the life cycle where this Net Benefit is positive represent points in time where cable injection is the more optimal intervention option to be executed as opposed to replacement. The time (t) at which the injection intervention reaches its maximum benefits becomes the Optimal Injection Timing (OIT).

$$NB_{INJECT_{OIT}} = \sum_{t=0}^{ORT} MAX\left(INJECTION_{NET_{BENEFIT}}(t)\right)$$

(Equation 4)

Where:

$INJECTION_{NET\_BENEFIT}(t)$ = the net benefit of injection, measured year-to-year.

ORT = the optimal timing of the replacement intervention.

NB_INJECT_{OIT} = the net present value of the benefit of injection, at the optimal timing of injection. It is at this time that the maximum benefits of injection are achieved.

The FIM makes its final recommendation as to whether the cable should be replaced or injected, based upon the current age of the evaluated cable asset, in comparison to its Optimal Injection Timing. Under certain circumstances, a cable may have already passed beyond its Optimal Injection Timing value, and at its' current age, cable replacement may become the more economically viable intervention option.

The Net Benefit of Cable Injection is shown graphically in Figure 15, calculated across the life cycle of the Existing Asset. Should the existing asset's age happen to fall between 20 and 40 years, cable injection will be selected as the optimal intervention option. Should the cable be older than 40 years, replacement will become the optimal intervention option. In this example, the Optimal Injection Time will be at 28 years, where the Net Benefit value of Injection is maximized.

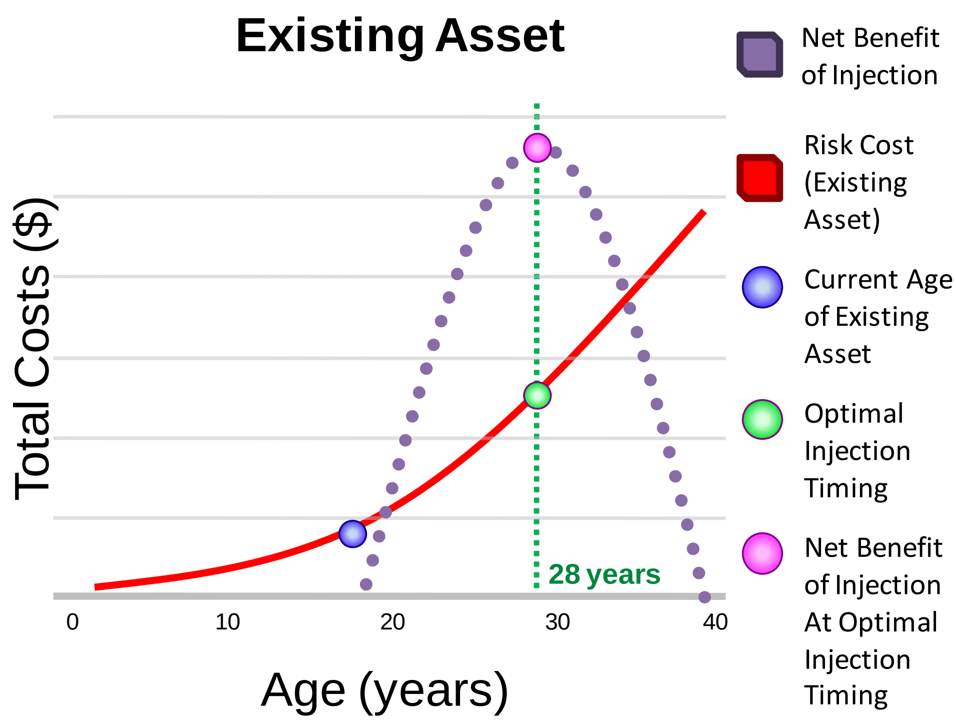


Figure 15 – Net Benefit of Cable Injection across Existing Asset Life Cycle

Each of the assets within the cable injection pilot study was evaluated within the FIM, to determine the optimal intervention solution and timing. Actual planned outage duration times and rejuvenation (life extension) benefits provided in Section 3 were applied within this study, for both replacement and injection activities. Due to the tremendous variations in customer outages, it was assumed that a planned outage would have the same impact as a forced outage to the customers.

5.2.2 Quantitative Results

The final results with regard to this quantitative assessment varied between the Novinium and Transelec vendors. This variation was primarily due to the differences in outage durations between the two injection processes.

With respect to Novinium, none of the studied cables were recommended for cable injection. The average Optimal Intervention Age was 57 years. With respect to Transelec, only 7.78% of the studied cables received a positive Net Benefit value for cable injection. The average Optimal Intervention Age was 46.4 years.

These results are logical when accounting for the material and labour costs, outage costs and the 40 year and 20 year life extension offered by the two rejuvenation options, in relation to the 40 year life expectancy benefits offered by full cable replacement. Since a very low percentage of assets receive a positive net benefit for injection, it can be concluded that it is not economically viable to execute injection activities as opposed to replacement.

Figure 16 provides a summary of results from this quantitative analysis, for both the Novinium and Transelec approaches.

NOVINIUM				
Average Optimal Intervention Age (years)	# of Transformers in Injection Area	Total Cables Studied (meters)	Total Cables Successfully Injected (%)	Total Cables Recommended for Injection (%)
57.4	46	8,137	96.11%	0.00%
TRANSELEC				
Average Optimal Intervention Age (years)	# of Transformers in Injection Area	Total Cables Studied (meters)	Total Cables Successfully Injected (%)	Total Cables Recommended for Injection (%)
46.4	35	6,658	75.68%	7.78%
TOTALS				
Average Optimal Intervention Age (years)	# of Transformers in Injection Area	Total Cables Studied (meters)	Total Cables Successfully Injected (%)	Total Cables Recommended for Injection (%)
53.4	81	14,795	85.70%	3.20%

Figure 16 – Results of Quantitative Analysis

Net present value analysis for these cable injection activities was performed for two cases:

(a) Cable injection is performed at the Optimal Injection Timing (OIT), where the Net Benefit of Injection value is maximized at this time (NB_INJECT_{OIT}).

(b) Cable injection is performed in 2008, as per the actual execution timing of both pilot jobs.

(c) For case (a), Figure 17 provides the graphical representation of the Net Benefit of Injection value per meter (NB_INJECT_{OIT}/meter) at the Optimal Injection Time for all of the studied cables within the Novinium and Transelec pilot jobs respectively. As shown in this figure, the bulk of this cable population receives negative Net Benefit values, ranging in cost from $0 to approximately -$5,500/meter. The largest quantity of cable (approx. 2240 meters in length) receives a Net Benefit of approximately -$320/meter. By contrast, few quantities of cables within the Pilot Jobs receive positive Net Benefits of Injection, varying from $0 to approximately $170/meter. The largest quantity of cable with a positive Net Benefit of Injection (approx. 730 meters in length) receive a Net Benefit of approximately +$2/meter. These results further illustrate that replacement is the more optimal intervention solution for the cable segments within both pilot jobs, as opposed to the cable injection procedures described in Section 4.2.

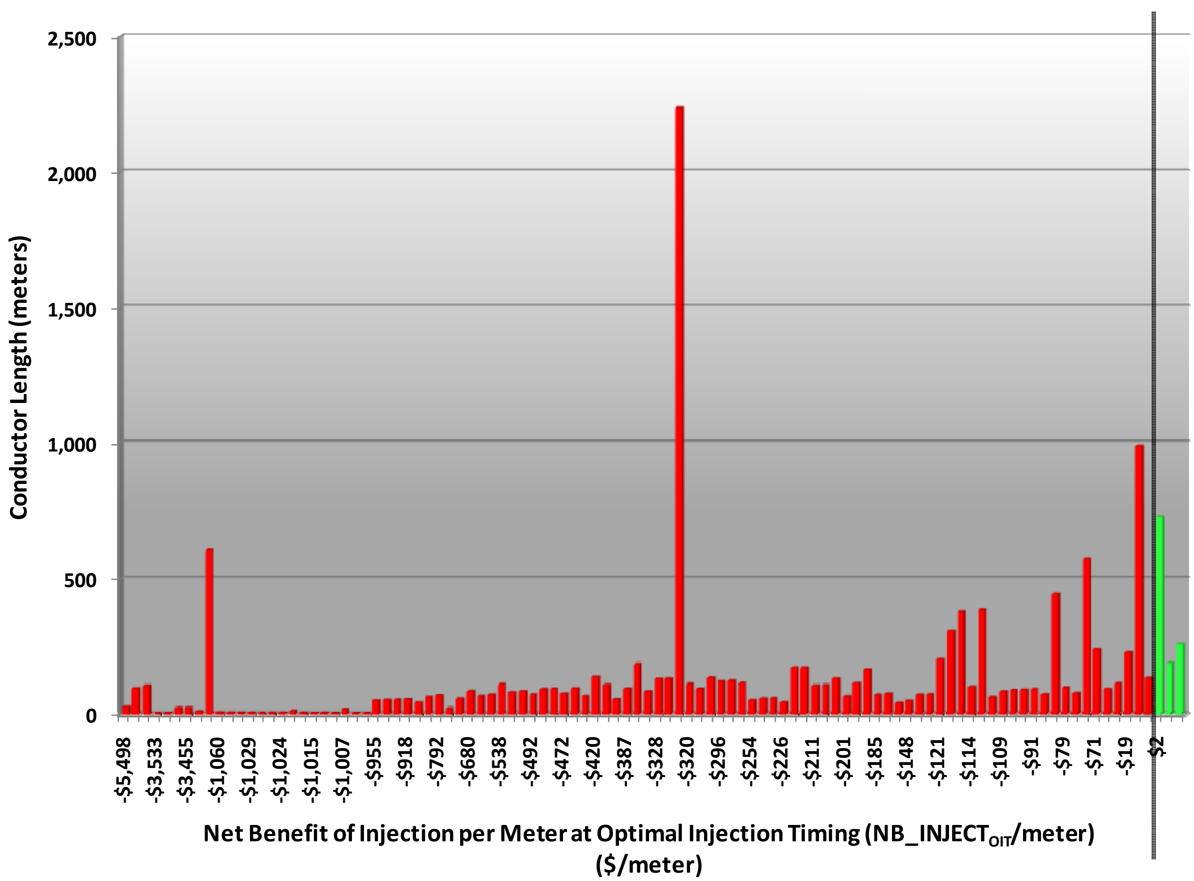


Figure 17 – Net Benefit of Injection per Meter Results at Optimal Injection Timing

For case (b), Figure 18 provides the graphical representation of the Net Benefit of Injection value per meter ($INJECTION_{NET\_BENEFIT}/meter(INJECT_{TIME})$) calculated at the specific time when both Cable Injection Pilot Jobs were executed (where $INJECT_{TIME}$ = 2008) for all of the studied cables within both Novinium and Transelec pilot jobs respectively. The results illustrate a larger population of cables which receive negative Net Benefit values from \$0 to approximately -\$83,000 per meter. A smaller population of cables now receive positive Net Benefit values from \$0 to approximately +\$60 per meter. These results further illustrate not only that replacement was the optimal intervention solution, but that cable injection activities as described in Section 4.2 were executed well before these cables had reached their economic end-of-life criteria.

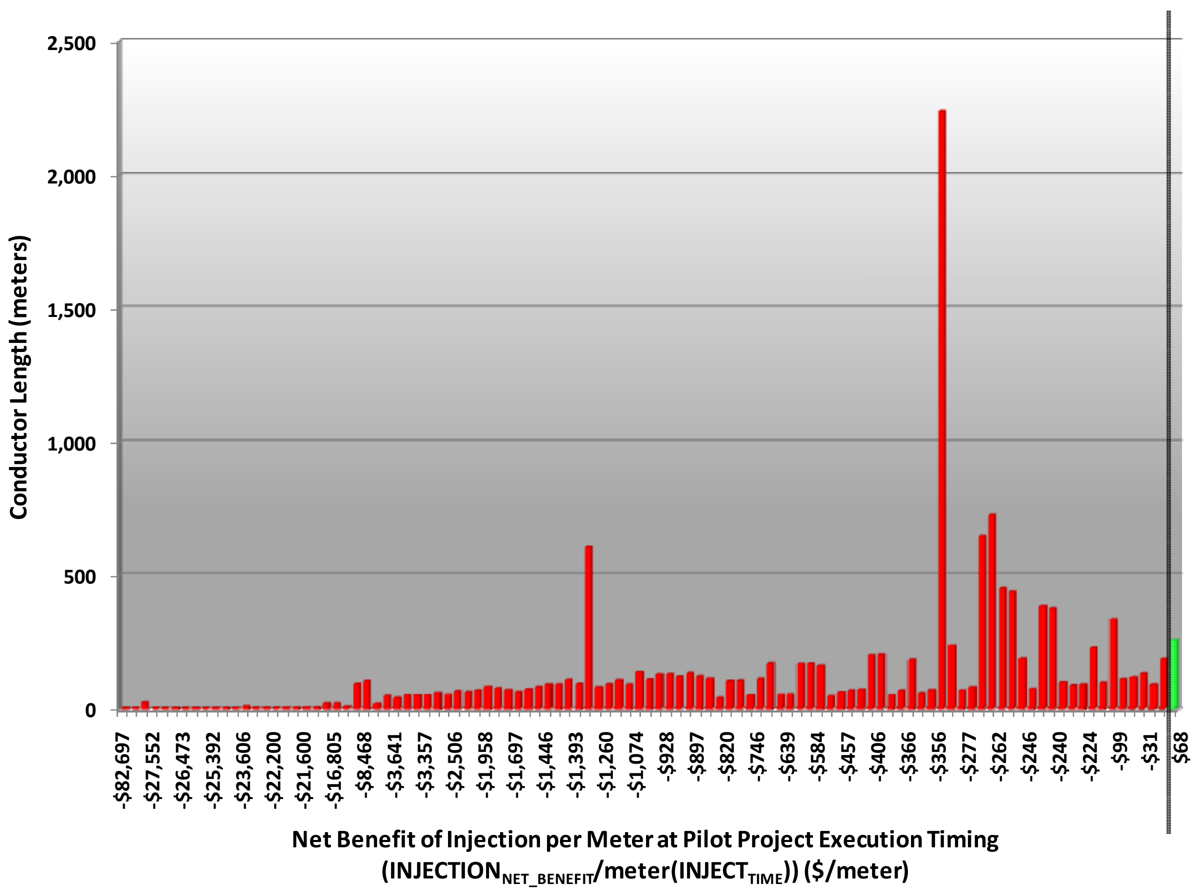


Figure 18 –Net Benefit of Injection per Meter Results at Pilot Job Execution Timing

By breaking down the cable injection activities from both the Novinium and Transelec pilot jobs respectively into 11 different jobs, Figure 19 provides a percentage breakdown of cables that received positive and negative net benefit values on a per job basis. This figure also reveals that only 8.4% of the studied cables within the two Pilot Jobs received positive Net Benefit of Injection values, as per Toronto Hydro's cable injection procedures described in Section 4.2. Figure 20 provides a similar percentage breakdown for each job, as per their execution timing in 2008. Similar to the Net Benefit results presented in Figure 18, these results indicate that the jobs were executed well before their optimal timings, as the total percentage of cables from both Pilot Jobs receiving positive Net Benefit values falls to 1.85%.

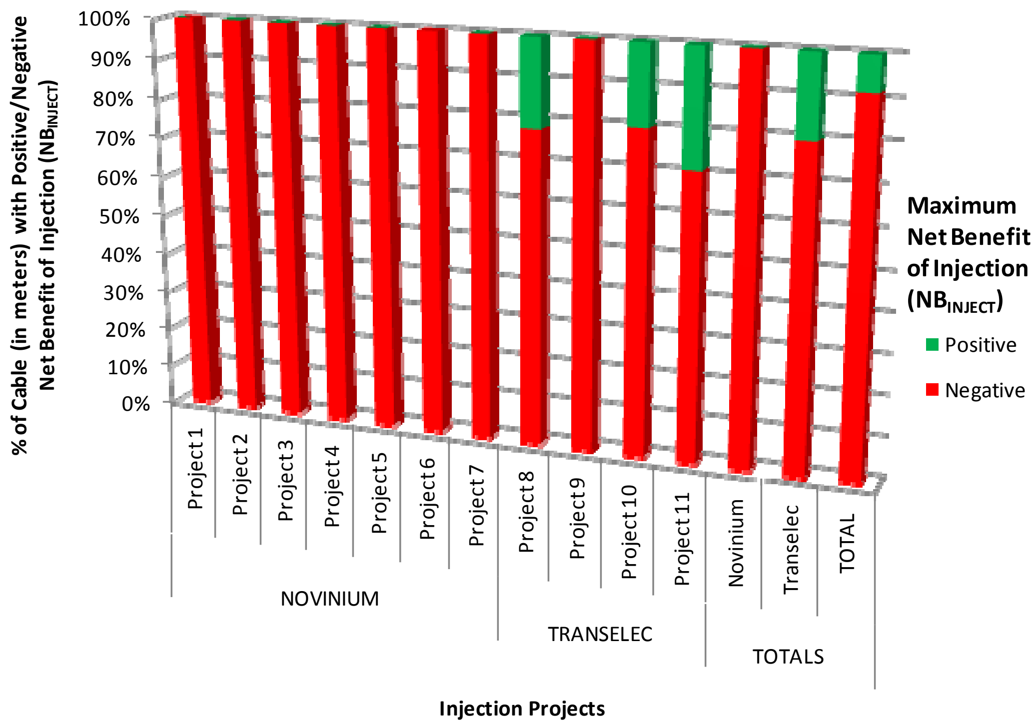


Figure 19 – Percentage Breakdown of Positive/Negative Net Benefit of Injection Results per Job

VI Conclusions

As per the results from the quantitative and qualitative comparative analysis' performed within this study, it is clear that cable injection activities did not yield favorable results when compared to cable replacement.

As per the qualitative analysis, there are a number of operational issues and limitations associated with the cable injection process, which prevent it from being a practical alternative to cable replacement activities. Both the Novinium and Transelec processes offer notable constraints and issues when executed in the field. In addition, there have been failures encountered on post-injected cables; three of which have occurred within a one year time span. These failures and the inconclusive evidence to pinpoint appropriate failure modes, suggest that these injection activities require further research and development before they can be accepted as proven successful alternatives.

As per the quantitative analysis, it is clear that Novinium's process results in unacceptably high interruption impacts to the customer when compared to cable replacement activities. While the capital cost of injection is lower when compared to the capital cost of replacement activities, the impact costs associated with injection are significantly higher. While the Transelec process provides a reduced impact to the customer, the majority of cables still do not receive a positive Net Benefit value for Injection. This is due to the reduced life extension properties of the Transelec injection formulation (20 years), when compared to the benefits of full cable replacement.

The qualitative assessment results taken on their own suggest that injection activities will yield positive net benefit values on a small percentage of studied cables. However, when factoring in both the quantitative and qualitative results collectively, it is clear that for submersible transformer installations employed at Toronto Hydro, the cable injection is simply not an ideal solution for direct buried cables, when compared to the benefits and costs associated with the cable replacement program.

Collectively, these results demonstrate the need to further refine and improve upon these cable injection processes, such that the operational constraints and post-reliability issues can be eliminated, and these processes may become economically viable when compared to the cable replacement program.

Despite the very high costs associated with replacing direct buried cables with new cables in concrete-encased conduit, this replacement approach ensures that Toronto Hydro is making the optimal decision from an economic and risk mitigation standpoint, when taking into account the qualitative and quantitative costs and benefits associated with alternative solutions.

VI References

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APPENDIX D

Equipment Failure Report # 2008-5

Component Reliability Planning

EQUIPMENT FAILURE REPORT

Issue Date: Sept. 22, 2008
Report # 2008 – 5 (draft)

FAILURE DETAILS	
Date of Failure:	February 1, 2008
Failed Equipment:	27.6kV 600 Amp PMH11 Motorized Switchgear
Equipment #:	PS14771+++SCPS (formerly SUG-138)
Location:	Kennedy Rd & William Kitchen
Ellipse ID #:	SC++++++05T7871
IT IS #:	N/A
CI:	N/A
CMO:	N/A
Feeder Affected:	Scarborough East TS SCNAE5-1M29

Background:

We recently experienced what we thought to be a RTU failure at the PS14771 (formerly SUG-138) motorized PMH11 switchgear. At the switch #1 location, the flags indicated the switch was open however the switch blades were in the closed position. A Work Request was initiated to have the switch replaced.

Failure Summary

On or around March 12, 2008, CRP was notified by DGH of a PMH11 switch failure involving a broken spring in the quick-make quick break switch mechanism. The broken spring did not result in an outage however it did have an impact on operational flexibility in the area. The switch was removed from service on March 12, 2008 and returned to Underwriters Rd. S&C were contacted to provide a return authorization to have the switch shipped back to S&C for repair and to provide a root cause analysis. The switch was repaired by S&C at Underwriters Rd.

Equipment Specifications:

Padmount Switch # PS11787 (formerly SUG-138)
600 Amp 27.6kV PMH11 Padmounted Switchgear (motorized)
Cat. # - 256163R3-T219
Manufacturer – S&C Electric Serial # - 05T7871
Year of Manufacture – Sept/05

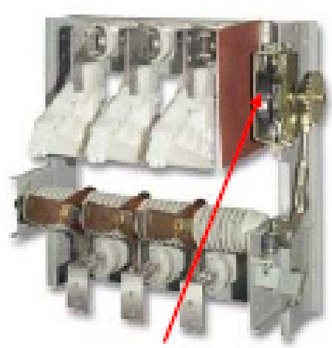
Inspection & Maintenance:

Padmount Switch # PS11787 (formerly SUG-138)
Installation Date – August 31/06
Last inspection performed – none (new switch)
Padmounted switches are typically inspected on a two year cycle. This switch was scheduled for inspection in 2008.

Observations:

The following photo #1 identifies the location of the spring in the quick-make quick break mechanism of the mini-rupter switch and photo #2 shows the broken spring in switch # PS14771.

#1



SPRING LOCATION

#2

BROKEN SPRING IN PS11787

From our inspection of the switch, it was apparent that the spring had failed prematurely. From the switch counter in the RTU, the switch had only seven operations since being installed on Aug. 31/06.

The broken spring was replaced at Underwriters by S&C technicians in May/08. Replacement was relatively simple and took approx. 1-1 ½ hours to complete.

S&C completed their failure analysis and reported the following:

- Edges of the spring were found to have rougher than normal edges.
- Rust was observed on the surface of the spring.
- The outside edge of the spring had an orange peel texture which indicates a high material hardness.
- Rusts spots were evident in the nine partial fractures in the spring.
- The hardness of the stainless steel spring was tested and found to be on the high side.
- S&C had received previous reports of failed springs in a few 2005 & 2006 units.
- It was identified that the stainless steel supplier changed the metal composition in 2004 and in doing so may have introduced contaminants which may have been a contributing factor to the internal corrosion in the metal.
- The stainless steel supplier has changed the formulation of the metal to address the reported flaws.

We have since learned of a second spring failure at Toronto Hydro in a PMH9 switch manufactured in Nov/06. This switch has been sent back to S&C for spring replacement and repainting.

S&C have agreed to replace any future broken springs found in our PMH switchgear free of charge (material cost and S&C Labour cost only). The replacement will include all springs in the switchgear regardless of their condition.

Replacement of the springs shall be coordinated through S&C and where practicable the work should be performed on site. A DGH crew will be required to assist S&C by establishing the required work protection to complete the replacements.

S&C will require two to three days notice to obtain the replacement spring(s) and schedule a crew to perform the replacement. They estimated that each spring will require 1 to 1 ½ hours to replace.

Initiating Event:

The initiating event would appear to be material flaws in the stainless steel. Once the flaws are exposed to the environmental elements, rust develops and causes stress risers, which in turn causes the fracture to propagate rapidly.

Corrective Actions:

1. Monitor any future PMH spring failures. (Action by: CRP)

2. S&C to provide free of charge replacements for any future broken springs within a three day timeframe. Replacements will include all springs in the switchgear regardless of their condition. (Action by: S&C)
3. Coordinate with S&C to have any future spring replacements performed on site where practicable. S&C Contacts: Jim Filleter @ 416-451-6739 or Ming Wong @ 416-249-9171. (Action by DGH)
4. Schedule for and provide S&C with the necessary work protection to carry out the replacements. (Action by: DGH)
5. Observe future spring replacements by S&C in efforts to gain experience and with the intent of eventually performing the replacements in-house. (Action by: DGH)
6. Coordinate with S&C the repair of any PMH switchgear that is returned from the field having broken springs. (Action by: Inventory Management)

Reported completed by:
Don Pemerowski – Component Reliability Planning

APPENDIX E

EHS Bulletin: Pad-mounted Switches

August 2010 – Issue: Equipment, Padmounted Switches (remote and manual)

EHS Bulletin

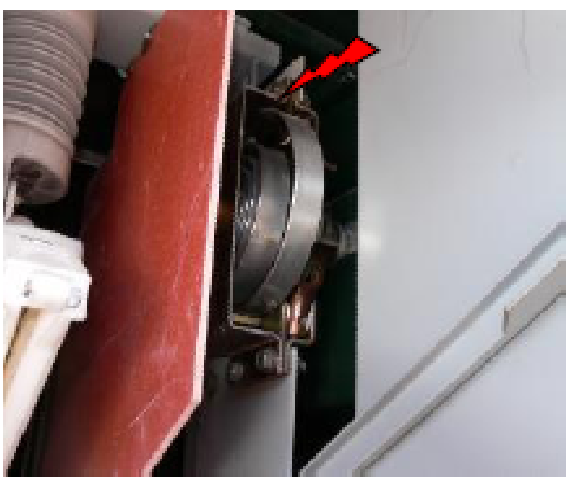
Posting Date: August 12, 2010
Removal Date: September 12, 2010

Padmounted Switches (Remote and Manual)

During a recent remotely operated PMH failure that caused a major outage, Asset Management identified a hazard with the old (2004-2010) "Quick-make/Quick-break" springs used in all Padmounted switchgear and ScadaMate switches.

The switch "Quick-make/Quick-break" springs could break mid-way during their operation and could cause an arc. The new procedure states that prior to the operation of any manual PMH switchgear they should be **visually inspected**. Look for cracks or spring deformation as signs of a break in the spring.

The pictures below are silver springs that are broken completely or partially:



If you find a defected silver spring, please tag it and send a request to the Work Request Desk to repair the unit.

All suspect remotely supervised and motor operated switches have been identified and are scheduled for replacement this year. Eventually all silver springs will be replaced with "Gold" springs.

My Goal is Zero

EHS Bulletin – 2010 – 011

Toronto Hydro Environmental, Health and Safety Bulletins are intended for internal use only unless otherwise authorized.

APPENDIX F

Underground Infrastructure Business Case Evaluation (BCE) Process

The business case evaluation (BCE) process involves the calculation of the net benefit of a capital job and incorporates quantified estimated risk, which is calculated based upon the asset's probability and impact of failure. The probability of asset failure is determined using the asset's age and condition. The impact of asset failure is derived from 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 of asset failure with the impact of asset failure provides the quantified estimated risk of asset failure.

1.1 Life Cycle Cost & 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 until that time. These functions are validated either directly by THESL or through the assistance of asset life studies from third-party consultants. The impacts of failure are then quantified by accounting for the direct costs associated with the materials and labour required to replace an asset upon failure, as well as the indirect costs. These indirect costs would include the costs of customer interruptions, emergency repairs and asset replacements. The final estimated risk cost produced represents the product of a hazard rate function for the given asset and its corresponding impact costs. Lastly, as shown in Figure 1, the lifecycle cost is produced, representing the total operating costs for a new asset, taking into account the annualized risk and capital costs 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.

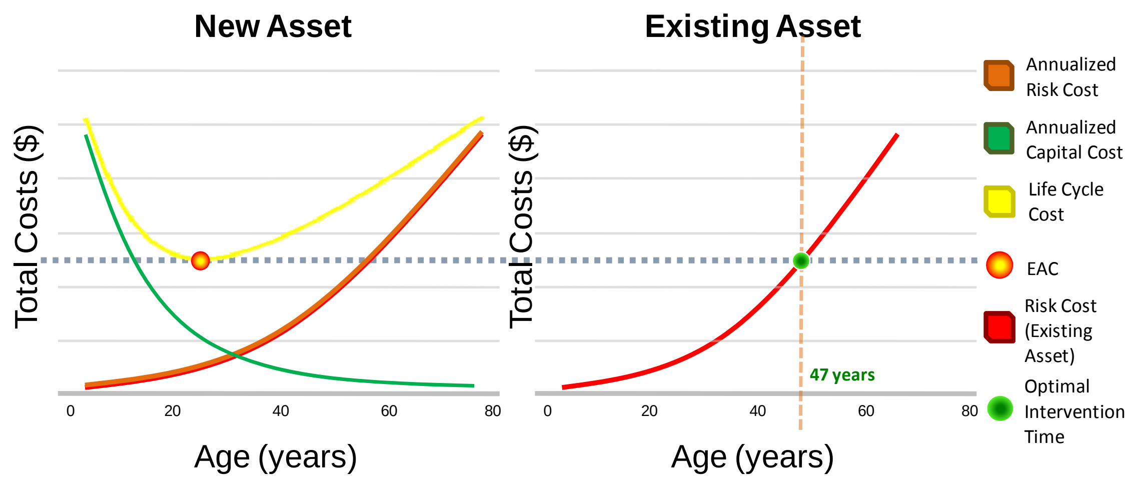


Figure 2: Typical Example of Optimal Intervention Time (Existing Assets)

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 Underground Infrastructure segment represents an “in-kind” replacement project in which the existing underground assets are being replaced with new standardized versions of those assets, while the overall configuration associated with this infrastructure remains the unchanged.

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 are taken into account.

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

The optimal year is the lowest point on the Project Net Cost curve, represented by the blue curve in Figure 3, meaning 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.

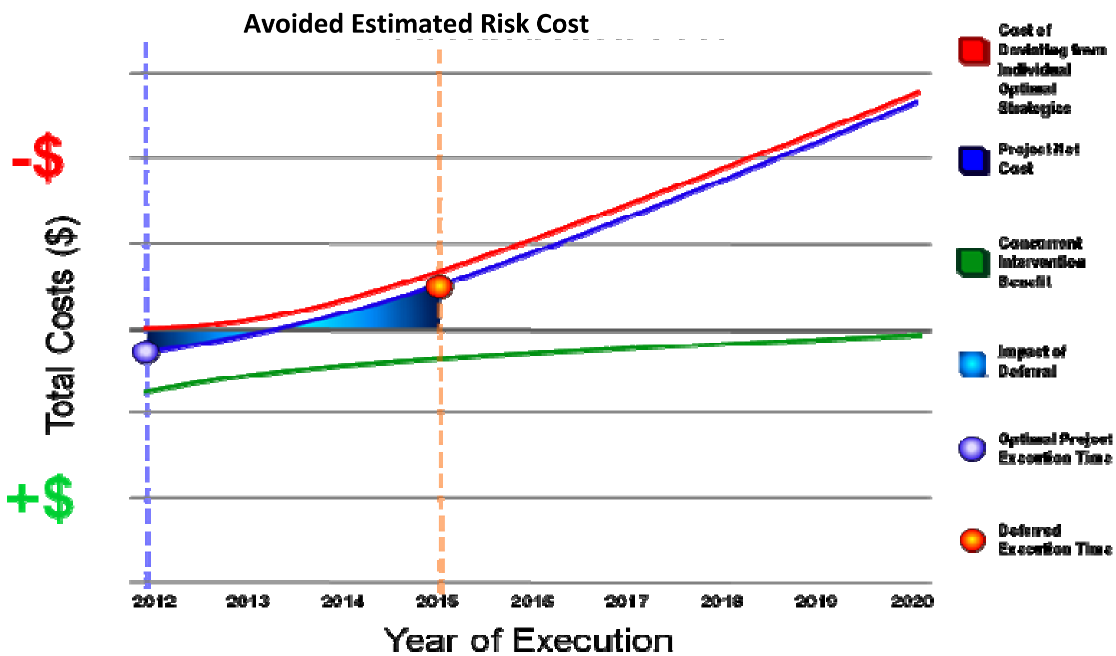


Figure 3: Example of Project Net Benefit Analysis for Job-Based Approach

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

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

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

Table 1: Avoided Estimated Risk Cost for Underground Infrastructure Segment

Business Case Element	Cost (in Millions)
Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015))	$354
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	$124
Avoided Estimated Risk Cost = **(PV(PROJECT$_{NET_COST}$(2015)) – PROJECT$_{NET_COST}$(2012))**	**$230**

ICM Project – Underground Infrastructure and Cable

Paper Insulated Lead Covered (PILC) Cable – Piece Outs and Leakers Segment

Toronto Hydro-Electric System Limited (THESL)

I EXECUTIVE SUMMARY

1. Project Description

PILC cable in THESL's distribution system is primary cable at either 13.8kV or 4.16kV. This cable has been used extensively in the downtown core to connect commercial and industrial customers to either 13.8kV terminal stations, or 4.16kV substations, and in some cases to connect one terminal station to another. PILC was the first type of underground cable installed in Toronto and THESL currently has approximately 1,305 kilometres of PILC in the system.

This cable type is compact and until it's outer lead cover becomes cracked or develops pin holes, is impervious to water ingress. These features made this cable type the primary cable type of choice downtown where space was at a premium, chambers were small and often accumulated run off and ground water.

Until about 1990, THESL did not consider cracked and leaking cables as defective and confined space work practices had not yet matured (See Figure 1). It was normal operating practice to work in and around energized leaking PILC cable, and move energized cable out of the way to make enough room to enter, work in, and exit chambers. Since that time, work practices have changed and today leaking PILC cables are considered defective, presenting potential safety hazards to workers, environmental concerns, and remediation requirements.

Figure 1: Leaking PILC Cable (January 18, 2012)

This segment includes 17 discrete jobs to repair and replace Paper Insulated Lead Covered (PILC) cable in 2012, 2013, and 2014 at an estimated cost of $23.97M.

Each cable chamber in each job must be inspected to determine if any deficiencies, other than the known leaking cables and cables requiring piecing out, have occurred since the last inspection.[1] Leaks can occur along the cable itself or on the lead sleeves encapsulating cable splices. As part of the work, cables will be placed and racked in a way such that the center of the cable chamber remains clear of cable for safe access and egress. In some limited cases, a leaking PILC cable can be repaired with the replacement of the lead sleeve over the splice.

[1] As discussed more fully below in Section III, "piecing out" refers to the process of extending a cable in a chamber, usually by adding an additional piece of cable, such that it has the correct length to allow placement on cable racks, thereby permitting ample clearance for personnel entering a cable chamber, and also providing proper support to prevent damage to the cable.

Cables that have deteriorated beyond repair will be replaced with the new section running to the adjacent cable chamber.

Loading and switching limitations prevent this work from proceeding at a faster pace. Usually the work must be scheduled for the evening or weekends when load is lower. For each job, customers must be switched to alternate feeders before de-energization and grounding work proceeds.

The Bridgman to High Level PILC replacement is a special case in that these cables run between two stations (Figure 2). In addition to the hazards presented to workers, and the environmental risks associated with these leaking cables, their deteriorated condition has caused numerous HONI transformer trips.

Figure 2: Leaking Oil from PILC Cables Connecting Bridgman to High Level Stations (January 18, 2012)

2. Why the Project is Needed Now

The PILC jobs proposed are necessary to remove safety hazards that have caused injuries and near misses to underground workers. If nothing is done, this problem is expected to continue to grow, and increase the safety risk to the workers. In addition to the safety concern, the defective cables are leaking oil, creating a possible environmental concern, and faulting regularly, reducing system reliability.

Over the past 20 years, work practices have become more and more prescriptive, and the operating constraints and costs have escalated. THESL has been repairing leaking cables and piecing out cable in congested chambers each year but not keeping up with a growing backlog. With age, and load cycling, the lead covering has cracked in many locations and oil is leaking from the cable. This creates two potentially serious problems: the dielectric strength of the cable is compromised, and oil leaks into the cable chamber. Many cable chambers downtown are routinely filled with water to the point where these cables can be submerged, which further compromises the cable. During load cycling, these cables expel oil under load, and draw water into the cable as load subsides and the cables cool down. Because inspections where brittle, damaged PILC cables are moved within a chamber will likely create more faults than simply leaving the cables untouched, age is used as a replacement factor rather than Asset Condition Assessment for PILC cables.

Each year, many cable chambers become more congested with the addition of new customers and services in the downtown core. These congested chambers must be rebuilt to the current, larger standard to accommodate additional cables. During the course of rebuilding a chamber, the existing PILC cables, and other service cables in the chamber, must be lifted from their racks against the outside walls and suspended in the middle of the chamber in order to break the existing walls and widen the chamber. In order to restore the chamber to a condition that crews can safely enter and work, all of the cables must be pieced out to provide additional cable length in the chamber, and allow the cables to be re-racked against the walls to provide space in the center of the chamber for crews to insert ventilation hoses, ladders, and fall arrest/rescue equipment. The longer these chambers are left in an unimproved condition after rebuilding, the more likely PILC will begin to creep and leak oil, and the longer these chambers remain inaccessible to crews. This situation also limits the choices that engineers and planners have for cable routing and service connects.

Cable chambers in Toronto are considered to be confined spaces. Where work must be carried out in these spaces, it is conducted under strict protocols and governing rules in order to mitigate the associated risks to workers in accordance with governing safety legislation. A confined space data base is maintained to capture and log all leakers that are identified in order to make all workers aware of their existence, and support operations in the safe scheduling of work. In addition, the drains in these chambers are sealed, to protect the environment, which leads to a requirement for additional inspection to determine when water levels become high enough in the chamber that pumping becomes necessary.

A backlog of chambers requiring piece outs and leaker repairs now exists which contributes to a higher level of risk exposure for crews associated with confined space entry and rescue requirements, and operating restrictions that must be alleviated. Chambers that require piecing out generally cannot be entered or worked in without exposing workers to additional risk.

Good utility practice directs that hazards in the workplace be eliminated where it is feasible to do so and to correct situations that create unacceptable operating conditions such as the Bridgman to High Level cable replacement.

An example of a chamber requiring piecing out is shown in Figure 3 below.

Figure 3: Chamber Requiring Piecing Out at Yonge and Merton (January 16, 2012)

3. Why the Project is the Preferred Alternative

Several options have been considered for dealing with leaking PILC cable, and piecing out PILC cable in chambers including:

1) Defer the work;
2) De-energize all cables in the chamber prior to entry;
3) Repair leaking cables and perform piece out on an emergency basis;
4) Pro-actively schedule and repair all hazards and defects on a feeder basis.

Option 1: Deferring the work is essentially a run-to-failure option. This approach does not address the existing risks to workers associated with working in confined spaces where defective primary cable is in service. It also would expose customers to potential for extensive outages from collateral cable damage in a chamber should a cable fail. This option would also require that chamber drains to be blocked so oil does not enter the sewer system resulting in additional operating costs to pump chambers when work is required. Finally, it reduces the choices for routing new underground cable because the chambers remain congested. For all these reasons, this option is not preferred.

Option 2: De-energizing all of the PILC primary cables in the chamber prior to entry would eliminate many of the associated hazards for workers. However, in the downtown core, often the service and standby cables run in the same chambers and de-energizing both of them would create outages. With up to ten primary cables in a single downtown chamber, each with a capacity of 10MVA, this option would create multiple outages to a significant number of customers on a regular basis. As a result, this option is not feasible.

Option 3: Repair leaking cables and perform piece outs on an emergency basis. In many cases, workers are dispatched to cable chambers to investigate an event or situation only to find that there are leakers or piece out requirements that prevent them from addressing the situation that originally caused them to be there. If the original task was to restore power because of a cable failure, or some other urgent need, the leaking cables or piecing out work must be completed first. These operating restrictions become unmanageable as the backlog of leakers and feeders requiring piecing out increases. This situation also adds to the control room's switching and operating workload. Selecting this option for dealing with leakers and piece out requirements would mean that the work was unplanned. The result of unplanned work is often failure to complete all aspects of the job, or a requirement for substantial overtime. This option is not preferred because it prolongs the time to complete the original task and its cost.

Option 4: Proactive repair of leakers and piecing out chambers allows work to proceed in a planned way, focussing on the highest priority areas. Feeders with multiple leakers and chambers requiring piecing out can be scheduled for isolation and all of the associated hazards and defects can be addressed at the same time while the feeder is out of service. This approach is the most efficient and preferred approach.

The various options considered are summarized below in Table 1 and fully discussed in Section IV. The calculations underlying Table 1 appear in Appendix A. Table 1 establishes that Option 4, proactively repairing or replacing the affected cables, offers the greatest benefit compared to any of the other options. For the reasons above, it is the preferred alternative.

Table 1: Options for Addressing PLC

Business Case Element	NPV (in Millions)
Option 1 — Deferral of Repair and Replacement Activities Cost of Ownership **[CO1]**	**$36.2**
Option 2 – De-energize Feeders within Cable Chamber during work activities—Cost of Ownership **[CO2]**	**$3,005**
Option 3— Repair Leakers and Cables Requiring Piece Outs When Performing Emergency Work –Present Value **[CO3]**	**$30.4**
Option 4— – Proactively Repair or Replace the Affected Cables – Present Value **[CO4]**	**$22.2**
Option 1 versus Option 2 NPV [CO1-CO2]	-$2,969
Option 1 versus Option 3 NPV [CO1-CO3]	$5.8
Option 1 versus Option 4 NPV (preferred Solution) [CO1-CO4]	**$14.0**

II DESCRIPTION OF WORK

1. Bridgman to High Level PILC Feeder Replacement

1.1. Objectives

After the near miss incident that occurred on a feeder connecting Bridgman to High Level stations on December 15, 2011, and explained in detail in Section III-1.1, all the PILC cables connecting these two stations and housed in the same civil infrastructure were inspected by THESL personnel. The results of these inspections show that many of the cables are leaking beyond the point of repair. Faults in these cables have taken a HONI transformer out of service six times in the past one and a half years which is not a sustainable approach for continuity of service, and it is also putting HONI assets at risk at the station.

The objective of this job is to address THESL's safety and operational issues, as well as concerns about HONI's equipment.

1.2. Scope of Work

The Scope of Work includes replacement of eight feeders that run between Bridgman and High Level Station. The feeders are A31BH, A32BH, A37BH, A38BH, A43BH, A44BH, A45BH and A46BH. Since all these cables are single phase, 1500kcmil, a total of 24-1500kcmil cables, over a distance of 455m is needed. This equates to a total distance of 10.9 kilometres of new 1500kcmil cable. Because of the lack of suppliers of lead-based PILC cable today, along with the hazards associated with leaking PILC cable, the 1500kcmil PILC cable will be replaced with 1500kcmil TRXLPE cable. This cable is a larger diameter and to accommodate this cable, the civil infrastructure needs to be rebuilt. The estimated cost of this job is $14.8M.

ICM Project | PILC Piece-Outs and Leakers Segment

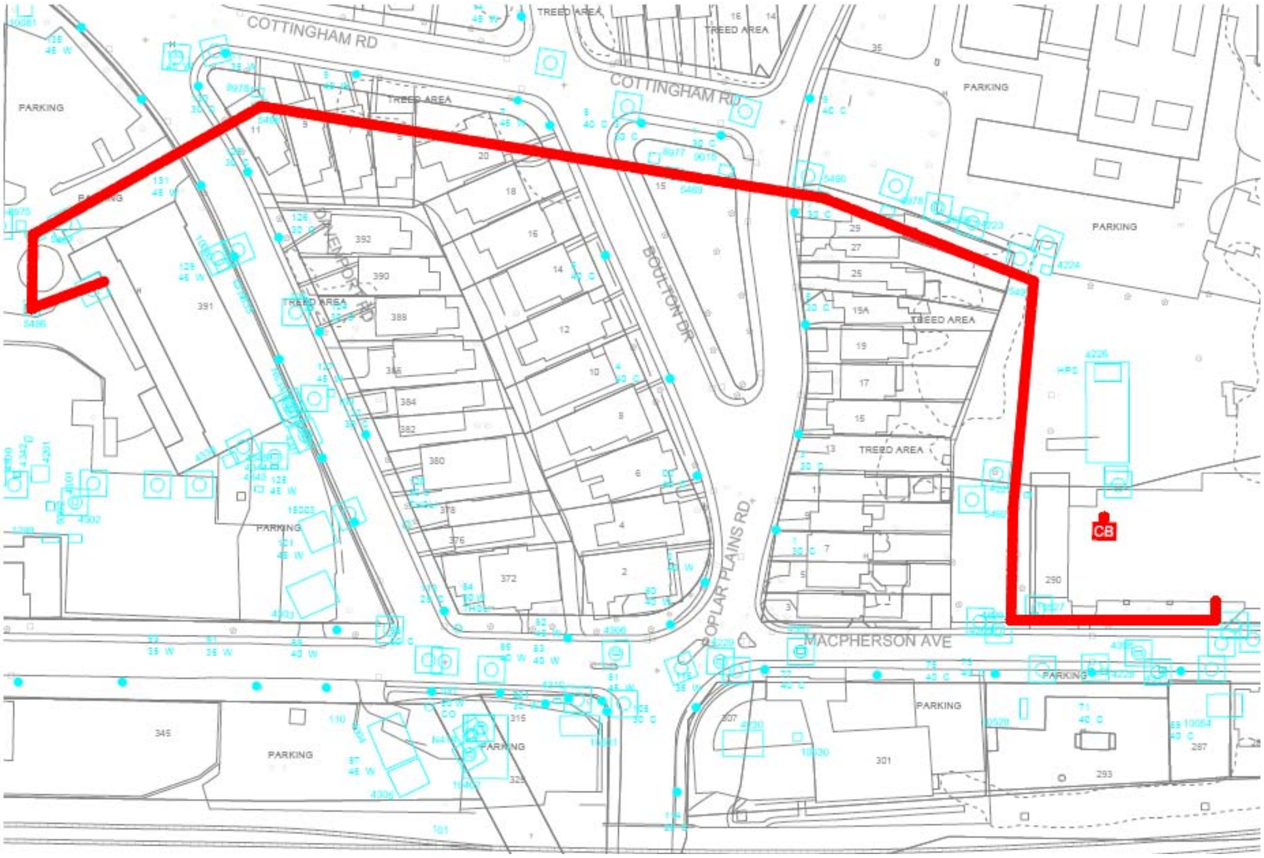


Figure 2: Project Map and Locations

Table 2: Required Capital Costs

Job Estimate Number	Job Title	Job Year	Total Estimated Cost ($M)
24463	Bridgman to High Level PILC Feeder Replacement	2012-2013	14.8

1.3. Need

In one safety-related incident, a PILC cable between Bridgman Station and High Level Station faulted and resulted in a near-miss arc flash. Upon investigation of the incident, many leaking PILC cables where discovered in the cable chambers between the two stations. As leaking cables present a hazard to the underground workers, workers are required to leave the cable chamber upon identification of a leaking cable and not to re-enter until the cable is de-energized and repaired. Because of the extent of the leaking oil from the PILC cables and because the cable is the oldest, belted type currently found in the THESL system, it is necessary to replace the entire cable. The modern standard 1,500kcmil TRXLPE cables will not fit in the existing three-inch ducts, so the duct banks and cable chambers must be rebuilt.

PILC cable faults have tripped the HONI station transformer pilot wire/blind spot protection six times in the past year and a half, and require HONI to take remedial action to verify the health of their transformers following each incident. As a result, HONI is requiring that THESL resolve this problem in a timely manner.

Figures 3, 4, and 5 show the leaking PILC cables that connect Bridgman and High Level stations which are planned for replacement. One PILC cable had such a large hole in it that the Emergency Trouble Crew had to be called in to address the problem immediately, as shown in Figure 5.

Figure 3: Leaking Oil from PILC Cables Connecting Bridgman to High Level Stations (January 18, 2012)

Figure 4: Leaking Oil from PILC Cables Connecting Bridgman to High Level Stations (January 18, 2012)

Figure 5: Leaking Oil from PILC Cables Connecting Bridgman to High Level Stations (January 18, 2012)

2. Piece Out and Leaker Repairs

2.1. Objectives

There are 16 jobs in this segment to piece out rebuilt cable chambers and repair leaking PILC cable in 2012, 2013, and 2014 at an estimated cost of $9.17M. The discrete jobs are listed, and locations depicted, in Table 3 and Figure 6, below, respectively.

ICM Project | PILC Piece-Outs and Leakers Segment

1 **Table 3: Piece Out and Leaker Jobs**

Job Estimate Number	Job Title	Units	Job Year	Total Estimated Cost ($M)
21216	Carlaw Station Piece Out and Leakers	24	2012	0.51
21217	Leaside Station Piece Out and Leakers	21	2012	0.24
21218	Esplanade Station Piece Out and Leakers	12	2012	0.11
21219	Glengrove Station Piece Out and Leakers	15	2012	0.29
21220	Cecil Station Piece Out and Leakers	17	2012	0.20
21221	Duplex Station Piece Out and Leakers	41	2012	0.61
21222	Main Station Piece Out and Leakers	31	2012	0.58
24682	Windsor Station Piece Out and Leakers	49	2013	0.68
19798	Windsor Station Piece Out and Leakers II	8	2013	2.24
24684	Strachan Station Piece Out and Leakers	37	2013	0.62
24687	Dufferin Station Piece Out and Leakers	55	2013	0.89
19554	Terauley Station Piece Out and Leakers	49	2013	0.76
24688	Bridgman Station Piece Out and Leakers	17	2014	0.17
24703	Gerrard Station Piece Out and Leakers	12	2014	0.10
24706	Basin Station Piece Out and Leakers	3	2014	0.05
24711	4kV Stations Piece Out and Leakers	103	2014	1.15
Total				**9.17**

ICM Project | PILC Piece-Outs and Leakers Segment

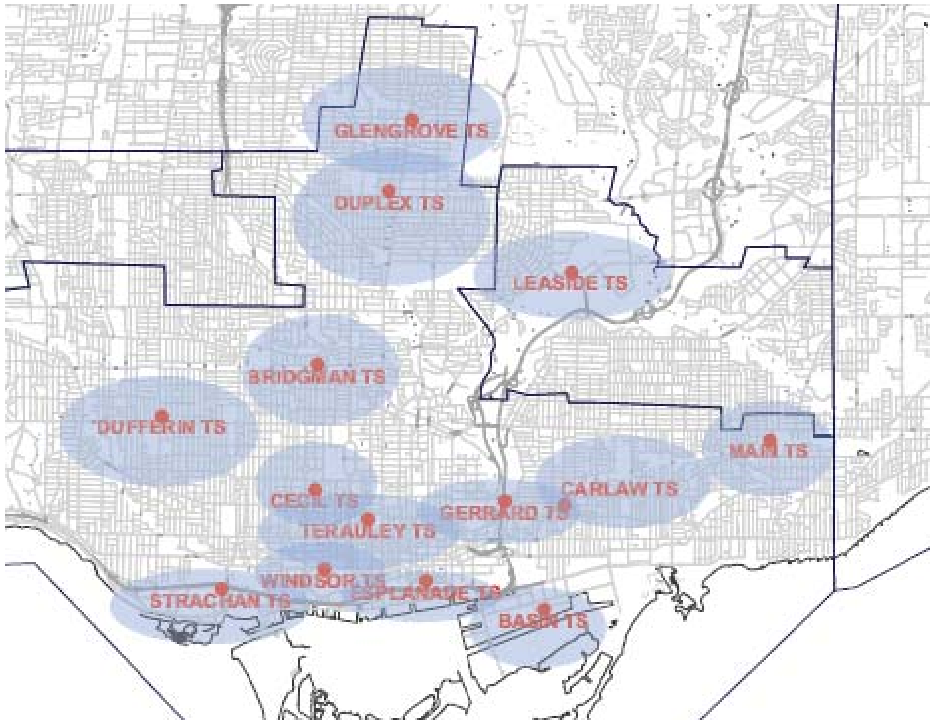


Figure 6: Location of PILC Leaker Repairs

2.2. Scope of Work

For each job, crews inspect each cable chamber to determine the inventory of hazards in order to establish a work plan for the load transfers, isolation, and work area protection required. Partial road closures may need to be coordinated with the City to allow for equipment to occupy the roadway while cable is being pulled. This pulling equipment includes a truck with a wheel trailer parked at one cable chamber which feeds the cable, and a truck with a winch trailer park next to the second cable chamber pulling the cable. Since a feeder must be de-energized for these repairs to take place, all piece-out and leakers are repaired at all locations on a given feeder when it is de-energized. This is expected to minimize the total cost of work and the total outage time to repair all known issues on a feeder, instead of taking a whole feeder out of service each time, to only repair or replace deficiencies at a single location. Where possible, the splice or cable will be repaired instead of a new cable being pulled, thereby reducing the total cost of this work.

Because of the hazards associated with leaking PILC cable, the operational constraints they introduce, and the time associated with splicing new cable into an existing cable, a number of kits have been trialed to encapsulate certain types of PILC leakers. It was expected that the repair time required could be reduced by installing a kit rather than cutting out the leaking portion of cable and replacing it with a new portion plus two splices.

Ultimately, kits were rejected primarily for two reasons. First, it is impossible to determine how compromised a cable is once it has been leaking for an undetermined length of time. Consequently, there is concern that encapsulation only covers up a defect. The hazard remains and, in essence, becomes a fault waiting to happen. Second, the kits that were tested eventually started to leak again after a number of load cycles.

III Need

Primarily in the downtown area, underground 13.8 kV and 4.16kV feeders commonly utilize oil-impregnated PILC cable. THESL currently has approximately 1,305 kilometres of PILC in the system. The cables perform well as long as the outer lead jacket is not damaged. However, when mechanical and electrical stresses weaken the outer protective lead sheath that encapsulates the insulating oil, this oil may leak out of the cable, causing a deterioration in insulation strength. This type of cable is commonly referred to as a ‘leaker’ and has the potential to suddenly explode, flashover, or present an electrical contact hazard to workers in the vicinity. In addition, the oil is an environmental concern. As a result, the water containing oil from the leaking cables in a cable chamber must be pumped out, tested, and processed for contaminants.

PILC cable is also used to connect THESL’s station switchgear assets to the high voltage transformers owned by Hydro One Networks Inc. (HONI). When these PILC cables leak and fault, the HONI-owned transformer protection systems operate, disconnecting the associated HONI-owned transformer, resulting in 35 MW of lost capacity and creating a single contingency situation. In addition, HONI personnel must be dispatched to assess the situation and ensure satisfactory operating conditions prevail. As a result of numerous transformer protection operations, HONI now requires THESL to take action to resolve the problem.

An energized PILC cable carrying up to 10 MVA of load can be seen below in Figure 7, with oil leaking out of the lead sleeve.

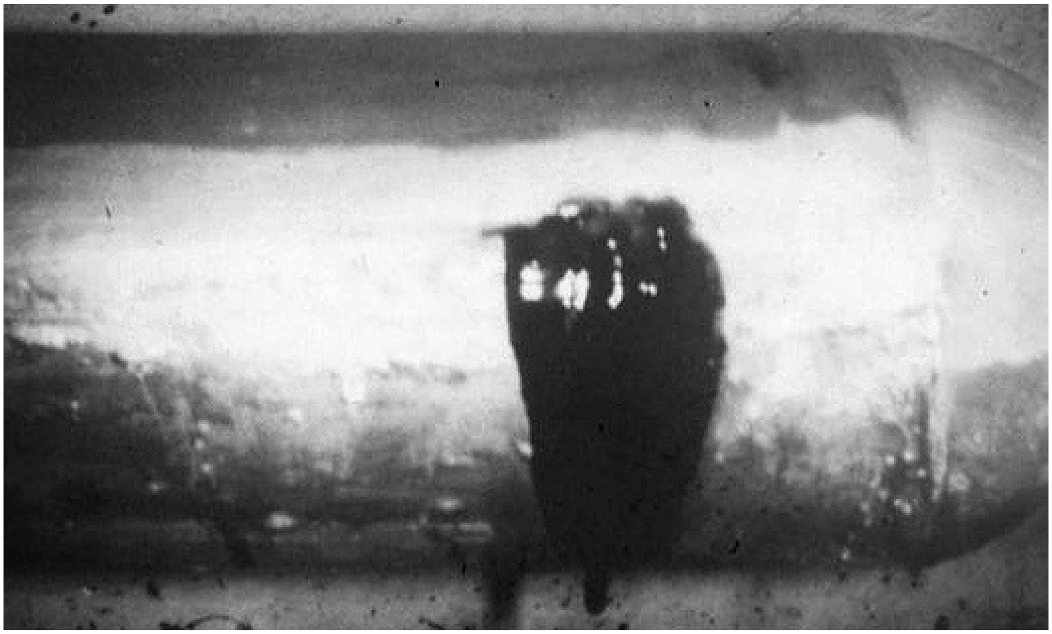


Figure 7: Oil leaking out of cable splice

Currently, there are 91 identified cable chambers that are severely congested because PILC cables are not adequately racked on the chamber walls; they run through the middle of the chamber and are often temporarily suspended from the roof. This poses a risk to THESL underground workers as they cannot enter a cable chamber without direct contact with the cable; if the cable faults when the worker contacts the cable while entering, as occurred in the safety incident detailed below, the worker can be severely injured. In addition, the cable congestion within a cable chamber creates opportunity for the failure of one cable and can result in collateral damage to other nearby cables, further compromising the reliability of the underground system. It is essential that cables are properly separated and supported in a cable rack within the cable chamber. Figure 8 below shows a cable chamber that workers are not able to safely enter because of cables that require piece outs. 'Piece out' is the term used for arranging the cables in the cable rack, usually by adding an additional piece of cable or by replacing the cable from the closest cable chamber, if necessary. Figure 9 below shows the desired cable racking after a piece-out job has occurred, where all the cables and splices are properly supported in a cable rack, and the workers are able to enter through the cable chamber opening without contacting any cables.

Figure 8: Before — Cable Chamber Requiring Piece Outs at Yonge and Mt. Pleasant (January 16, 2012)

Figure 9: After — Cable Chamber showing properly supported cables and splices in a cable rack within the cable chamber (January 18, 2012)

Several safety incidents have occurred as a direct result of damaged PILC cables. In one incident, a worker contacted a PILC cable splice that required piecing out while climbing down a ladder to enter a cable chamber. In this incident, the cable was not properly racked, but running unsupported and directly beneath the cable chamber opening. The worker received flash burns to his face, neck and shins, and further injured his forehead, buttock, and left knee as he fell from the ladder. Figure 10 and Figure 11 respectively show photographs of burns on the worker's pants and burns on the ladder, from this arc flash incident.

Figure 10: Burn marks and tears after worker experienced an arc flash from a cable that required piecing out (April 27, 2007)

Figure 11: Piece out cable is shown obstructing entry to cable chamber. Burns are seen on the ladder where the cable made contact with the ladder (Note: ladder not in original position but raised for the photo, April 27, 2007)

In another incident, a near miss occurred on December 15, 2011 while work was being carried out on a 13.8kV PILC tie cable from Bridgman to High Level stations. In this near miss incident, a second fault occurred when repairing a first fault on an adjacent cable. Moving the other cable was required because of congestion. However, due to age and condition, the PILC cable sheaths were brittle and cracked, resulting in oil leaking out of the lead sheaths and a reduction in dielectric strength. When the worker moved one cable to allow him to fix a problem on another cable, the cable faulted and arced .

In Figure 12, a leaking PILC cable can be seen in cable chambers neighbouring the near -miss chamber. In Figure 13, a hole from the splice that caused the near miss arc flash can be seen as the Trouble Crew repairs the cable. Finally, in Figure 14, a hole in the PILC insulation, after the outer lead sleeve has been removed during the repair, can be observed.

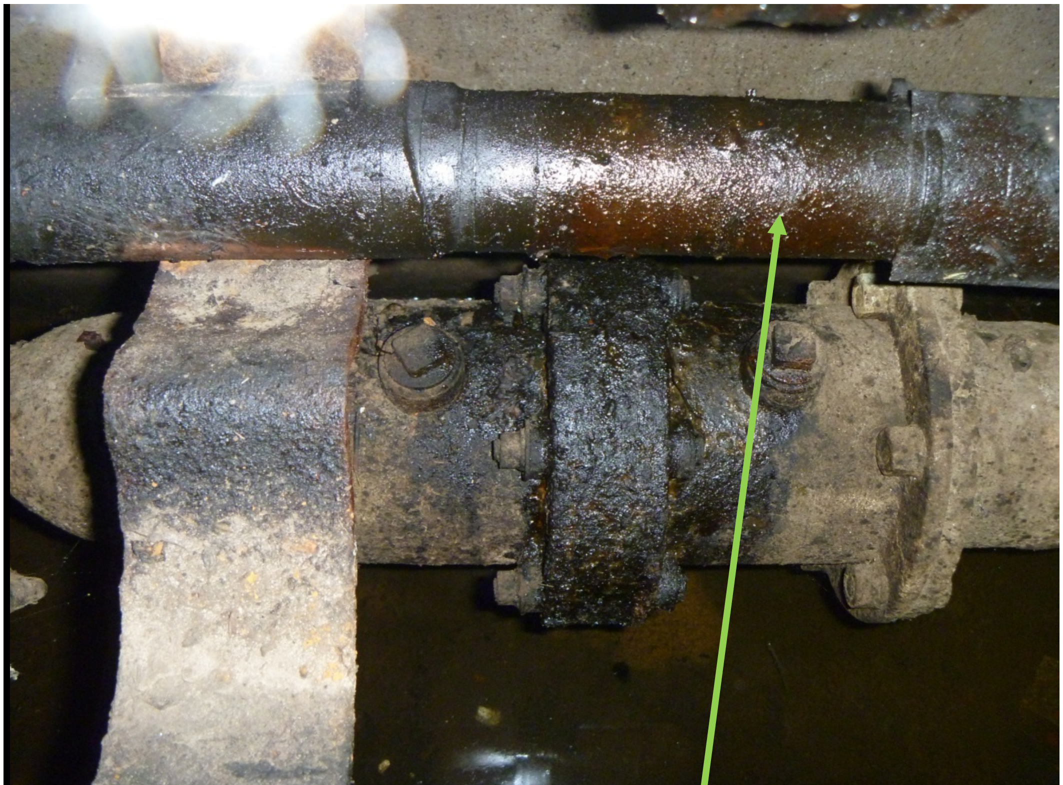


Figure 12: Near Miss Incident —Damaged, leaking PILC cable (December 15, 2011)

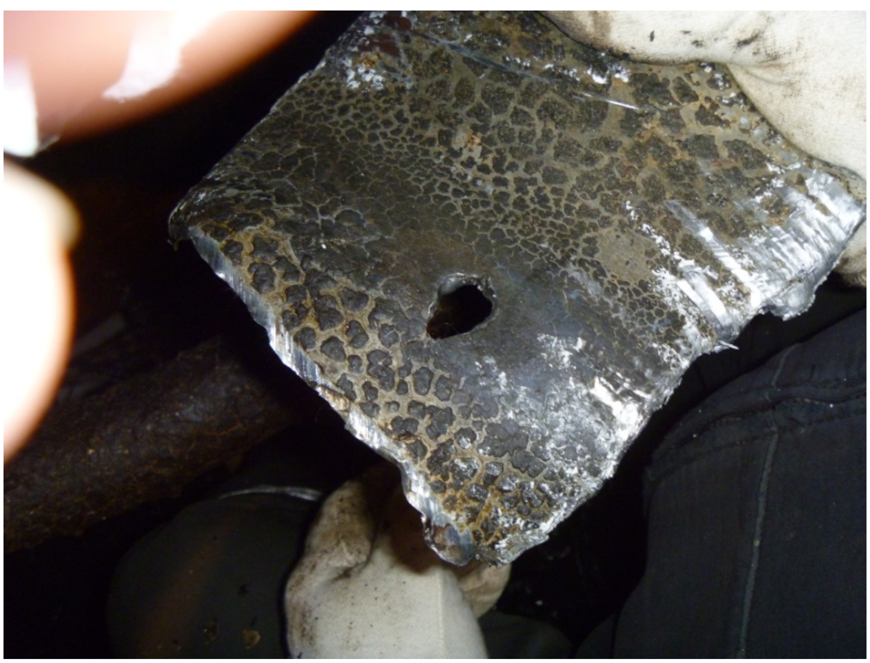


Figure 13: Near Miss Incident —Hole in Cable Joint Sleeve of A46BH (December 15, 2011)

1 **Figure 14: Near Miss Incident —Hole in Cable Insulation of A46BH, sleeve removed**
2 **(December 15, 2011)**

IV Alternatives Considered

There are four options available to address the issues with PILC cables:

Option 1 – Deferral of Repair and Replacement Activities

By deferring this work, hazardous conditions remain and continue to develop in downtown cable chambers. All damaged PILC, including the leaking cables and those that require piecing out, remain in the distribution system and continue to expose THESL workers to unsafe working conditions. Figure 15 below from the Electrical Safety Authority shows, in general, how injuries are precursors to fatalities, and enforces that these hazards must be removed from the system. The increased potential for safety-related injuries to workers, and environmental risks remain. In addition to safety, reduced productivity from emergency repairs taking twice as long when a leaking cable is found, reduced reliability from leaking and unsupported cables faulting more frequently, and added environmental costs from processing water in cable chambers that contain oil from leaking PILC cables, will also be expected with this option. The present value of the risk associated with this option is $36.2M which is detailed in Appendix A.

Figure 15: Injury Triangle from the 2010 Ontario Electrical Safety Report by the Electrical Safety Authority (ESA)

Option 2 – De-energize Feeders within Cable Chamber during work activities

Most chambers in the downtown area contain up to eight primary feeders. De-energizing all feeders present in a cable chamber whenever anyone is required to enter that cable chamber is not a feasible option since in most cases the normal and standby feeders for the associated customers run in the same chambers, and substantial outages would result. De-energizing all feeders would remove the hazards to workers associated with energized PILC cables, however, this option would result in additional and substantial outages of up to 50MVA to allow workers to enter cable chambers safely, and does not mitigate the environmental risk.

In 2011, there were 28,576 cable chambers and vaults entered by THESL workers. This option would increase customer interruptions (CI) by about 30% resulting in a present value of the associated risk associated of $3 Billion, which is detailed in Appendix A.

Option 3 – Repair or Replace Leakers and Cables Requiring Piece Outs when performing Emergency Work

Repairing or replacing leakers and cables that require piecing out, when a worker is required to enter a chamber containing these hazards to perform emergency work, introduces additional costs. Because of space constraints in a cable chamber, only a certain number of workers can fit inside. Because of this fact, the emergency work and repairs of the piece out and leakers cannot be completed in parallel, and will force one of these repairs to take place on premium-priced over-time, causing a higher cost to repair or replace the piece out and leakers. This option also is expected to do nothing to reduce the operating restrictions associated with leaking PILC and congested chambers. The present value associated with this option is $30.4M, which is detailed in Appendix A.

Option 4 – Proactively Repair or Replace the Affected Cables

Proactive repair or replacement of the affected cables allows all the damaged sections along the entire feeder, in numerous cable chambers, to be repaired or replaced while the feeder is de-energized. This minimizes the total job cost to address all PILC hazards along a feeder. By proactively repairing or replacing the damaged PILC cable, customers can usually be switched to stand-by feeders, allowing the repair or replacement to occur with a minimum number of customer outages. The present value of this option is $22.2M, which is detailed in Appendix A.

Preferred Option

In consideration of all the options and associated factors, Option 4 is preferred as it allows THESL to take advantage of planned feeder outages to proactively address all the sections of cable requiring piecing out and all the sections of leaking cable. Option 4 is the most cost-effective option, as seen in Table 4 below.

1 **Table 4: Present Value of Options**

Business Case Element	PV (in Millions)
Option 1 — Deferral of Repair and Replacement Activities Cost of Ownership **[CO1]**	**$36.16**
➢ Environmental Cost	$5.06
➢ Emergency Repairs—Additional Tool Time	$31.10
Option 2 – De-energize Feeders within Cable Chamber during work activities—Cost of Ownership **[CO2]**	**$3,005**
➢ Cost of Customer Interruptions	$3,000
➢ Environmental Cost	$5.06
Option 3— Repair Leakers and Cables Requiring Piece Outs When Performing Emergency Work –Preset Value **[CO3]**	**$30.38**
➢ 2012 Project Cost	$19.9
➢ 2013 Project Cost	$10.4
➢ 2014 Project Cost	$2.9
Option 4— – Proactively Repair or Replace the Affected Cables – Present Value **[CO4]**	**$22.2**
➢ 2012 Project Cost	$17.3
➢ 2013 Project Cost	$5.2
➢ 2014 Project Cost	$1.5
Option 1 versus Option 2 PV [CO1-CO2]	**-$2,969**
Option 1 versus Option 3 PV [CO1-CO3]	**$5.8**
Option 1 versus Option 4 PV [CO1-CO4]	**$14.0**

Appendix A

Detailed Calculations

Option 1— Deferral of Repair and Replacement Activities

- The average age of the PILC cable population is 28 years old. Assume that all cables are set to average age of the population of 28 years.
- Assume that if cable is replaced due to failure, no risk of environmental processing water exists.
- Assume life cycle (and PV calculation) ends at age 100.
- Assume there is no change in total number of piece out/leakers from year to year
- It takes twice as long to perform any task in a cable chamber containing piece out and leakers because of congestion. Average task when a cable chamber is visited is 4 hours long, and takes 2 people
- Assume the total environmental processing cost in 2011 is applied only to cable chambers containing piece-out and leakers, and each piece-out and leaker cable chamber must have its water environmentally processed each time it is visited
- Assume there are 2 segments x 4 feeders = 8 segments/chamber

Given

- Total Cable Chambers with piece-out and leakers = 484
- Average PILC Cable Segment =0.157km
- Total Cable Chamber Population = 10,854
- Total Chambers visited = 28,576
- Total Chambers with Piece-out and Leakers visited in 2011 = 1,301
- Average age of PILC cable = 28 years
- Useful Life of PILC Cable = 75 years
- Environmental Cost to clean a cable chamber =$243
- Cost of two underground cable people, for 4 hours, plus material, truck = $1,493

The risk only remains if the cable with the piece-out or leaker does not fail, and is not replaced with a new cable. Therefore, taking the average age of the population of PILC cables, and multiplying by the (probability of no having a new PILC cable) x (impact), a risk cost is calculated. This risk is taken from the average age until the population is 100 years old, and done for each cable chamber visited containing a piece out leaker. Finally, the present value in 2012 dollars is taken. The calculation of the probability of failure relies on the assets' Hazard Distribution Function ("HDF"), which represents a conditional probability of an asset failing from the remaining population that has survived up till that time. These functions are validated through the assistance of asset life studies from third-party consultants. The useful life for underground PILC cable is 75 years, meaning that 50% of the population will have failed by 75 years old.

When a leaking cable is present, the water in the cable chamber contains oil, and has to be pumped and processed. Using the calculations described above, this accounts for a present cost for a single cable over the life of a cable with a leaker of **= $ 3,893.**

Also, cables containing piece out and leakers take twice as long to perform work in them, as workers have to use mirrors to work around the problem, switch customers to de-energize leaking cables such that they can be worked on energized, etc. Using the calculations described above, this accounts for a present cost over the life of a single cable containing piece-out or leakers of **= $23,910.**

Given that 1301 cable chambers are visited each year that contain a piece-out and leaking PILC cables, the total present cost is 1301*($3,893 + $23,910) **=$36.1M**

Option 2 – De-energize Feeders within Cable Chamber during work activities

- The average age of the PILC cable population is 28 years old. Assume that all cables are set to average age of the population of 28 years.
- Assume that if cable is replaced due to failure, no risk of environmental processing water exists.

- Assume life cycle (and PV calculation) ends at age 100.
- Assume there is no change in total number of piece out/leakers from year-to-year
- Assume average cable chamber load is 3200kVA (6 feeders, 9MVA, operating at 60% load)
- The time the feeders require to be de-energized is 1 hour

Given

- Total Cable Chambers with piece-out and leakers = 484
- Average PILC Cable Segment =0.157km
- Total Cable Chamber Population = 10,854
- Total Chambers visited = 28,576
- Total Chambers with Piece-out and Leakers visited in 2011 = 1,301
- Average age of PILC cable = 28 years
- Useful Life of PILC Cable = 75 years
- Event Impact = $30/kVA
- Duration Impact = $15/kVA*h

An outage impact is calculated using 3200 kVA for 1 hour.

Outage impact= ($30/kVA)(3,200kVA) + ($15/kVA*h)(3,200kVA*1h) =$480,000

The risk only remains if the cable with the piece-out or leaker does not fail, and is not replaced with a new cable. Therefore, taking the average age of the population of PILC cables, and multiplying the (probability of having a piece-out leaker) x (impact), a risk cost is calculated. This risk is taken from the average age until the population is 100 years old, and done for each cable chamber visited containing a piece out leaker. Finally, the present value in 2012 dollars is taken.

The present value of de-energizing until the cable is 100 years old is $3.0M per chamber. It is assumed that a given load cannot be transferred to another feeder because the standby feeder would also run in the cable chamber where work is happening, and be de-energized. Given

1,301 chambers are visited a year, this number is **$3 Billion** if all feeders are de-energized each time a worker is required to enter a chamber.

Option 3 – Repair or Replace Leakers and Cables Requiring Piece Outs when performing Emergency Work

- Assume all 1,301 leakers/piece outs are addressed within a three-year time period.
- Even with staggering of work over a three-year period, do not account for existing risks (environmental/de-energization) from year-to-year.

Because of space constraints in the cable chamber, the emergency work will be completed first and then the repairs of the piece-out and leakers completed second, stretching half the job into premium priced, over-time. Given that the Bridgeman to Highlevel station ties job cannot be completed in this manner, only the piece-out and leakers jobs can be completed on over-time.

Considering the premium over time, and the fact that the dollars of this job are spent over a three-year period, the job costs each year are:

2012 = $ 19,850,950
2013 = $ 10,358,037
2014 = $ 2,933,222

The present value in 2012 dollars, equates to **$30.4 Million** using 6.06% discount rate.

Option 4 – Proactively Repair or Replace the Affected Cables

- Assume all 1,301 leakers/piece outs are addressed within a three-year time period.
- Even with staggering of work over a three-year period, do not account for existing risks (environmental/de-energization) from year-to-year.

All the dollars of this job are spent over a three-year period. Given the job costs each year:

2012 = $ 17,323,056

2013 = $ 5,179,018

2014 = $ 1,466,610

The present value in 2012 dollars, equates to $22.2 million using a 6.06% discount rate.