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Delivered by E-Mail

August 2, 2007

Ms. E. Kirsten Walli
Board Secretary
Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited's Distribution Revenue Requirement and Rate Application for the 2008, 2009 and 2010 rate years

OEB File No.: EB-2007-0680

We are counsel to Toronto Hydro-Electric System Limited ("Toronto Hydro"). We attach Toronto Hydro's Application for revenue requirements and corresponding rates for three individual and successive rate years commencing May 1, 2008 and ending April 30, 2011. This Application is being filed pursuant to the Board's e-Filing Services. We will be delivering two paper copies of the Application to the Board over the next few days.

Yours very truly,

BORDEN LADNER GERVAIS LLP

J. Mark Rodger

Encl.
copy to:

Anthony Haines, Toronto Hydro-Electric System Limited
Pankaj Sardana, Toronto Hydro-Electric System Limited

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INTRODUCTION

SCOPE OF APPLICATION

With this Application, Toronto Hydro-Electric System Limited ("THESL") seeks approval from the Ontario Energy Board ("OEB") for revenue requirements and corresponding rates for the three individual and successive rate years commencing May 1, 2008 and ending April 30, 2011. Essentially, this Application is for the combination of those three rate years with each rate year considered distinctly, rather than as a single rate period lasting three years with one approved tariff.

THE NEED FOR A COST OF SERVICE REBASING APPLICATION

It is necessary for THESL to apply to the OEB on a cost of service basis for the rate years covered by this Application because that is the only approach that will clearly accommodate THESL's need for annual rebasing. The alternative rate making approach involving an Incentive Regulation Mechanism does not provide for recovery of the significant capital spending in excess of depreciation and amortization that THESL plans to undertake. In order for THESL to recover the capital costs of its planned investments in the distribution system and other assets, the ratebase must be revalued in each successive year and corresponding rates be set accordingly.

In this respect THESL's situation differs from that of other utilities, which may face the prospect of a large investment (for a transformer station, as an example) over a one- or two-year period. In that circumstance a single revaluation of ratebase could substantially capture the required investment without subsequent revaluations, leaving open the possibility that that utility could then move into an incentive regulation framework.

In THESL's case, the evidence in this Application demonstrates the need for very substantial capital investments, not over one or two years, but over an extended period of

ten or more years. The required annual investments are significantly in excess of annual amortization, and ratebase is projected to increase correspondingly.

THESL cannot sustain an extended period of ratebase growth without the rate adjustments necessary to support that growth. While cost of service rebasing proceedings are designed to deal with those needs, there is no apparent mechanism to do so in the existing or anticipated incentive ratemaking systems.

Therefore, THESL believes that cost of service proceedings will be justified and necessary for annual rate setting purposes at least over the next decade. However, THESL recognizes that this will place demands on OEB and intervenor resources as well as its own, and wishes to minimize those demands subject to achieving a fair regulatory outcome. Consequently, THESL has applied for a test period consisting of three successive test years, with the expectation that if this approach is accepted by the OEB, the regulatory burden over that period will be reasonably reduced.

The proposed approach results from a balanced consideration of the benefits of reducing regulatory burden versus the risks to the utility and ratepayers of an extended forecast period. THESL is not prepared to forecast revenue requirements for a period beyond three years due to the possibility of unforeseen factors significantly changing costs in either direction. However, if the test period is shortened, regulatory resource costs to all parties would be correspondingly increased.

In summary, THESL believes that its approach of presenting three successive test years in this application represents an appropriate balance of the need to achieve a fair regulatory outcome with the needs to minimize regulatory burden and manage risk. THESL has structured this Application on that basis, and requests that the OEB process the Application accordingly.

GLOBAL ASSUMPTIONS AND CONVENTIONS

The evidence set out with this Application provides the costs constituting the proposed revenue requirement for each rate year together with the corresponding rates for that year.

This approach has made it necessary for THESL to make assumptions concerning the evolution of costs and rates over the three-year test period for the purpose of calculation and presentation. The principal assumptions underpinning this Application are:

1) The revenue requirements and corresponding rates for each rate year are approved by the OEB, and serve as the starting point for the succeeding year in calculating the revenue sufficiency/deficiency as well as rate impacts;
2) Parameters governing the cost of capital and return on equity in particular are derived by application of the OEB-approved methodology for the relevant variables as forecast at the time of this Application;
3) The OEB-approved adjustments to THESL's capital structure take place in 2008 and 2009 as prescribed;
4) Capital additions subject to the half-year rule for a given rate year are fully reflected (after amortization) in the opening balance of ratebase in the succeeding year;
5) All other stock variables (such as accumulated amortization and staff levels) for which continuity is required assume the year-end closing balance in one year as the opening balance in the next rate year;
6) Costs are stated on a fiscal-year (i.e., calendar) basis and revenue is stated on a rate-year basis, such that costs are matched with the revenues that are meant to correspond to those costs, despite the lag in receiving those revenues; and
7) The investment and operating plans for the prior year are approved and executed and serve as the basis of the plans in the succeeding year.

FORECAST UPDATES

Certain of THESL's forecasts have been based in part on values of exogenous items such as interest rates, degree days, tax rates, and other economic variables.

In the event that changes in these exogenous variables by the time of the hearing produce material changes in costs or rates, THESL plans to provide updated forecasts based solely on those exogenous variables.

COMPLIANCE WITH FILING REQUIREMENTS

THESL has prepared this Application in accordance with the filing requirements issued by the OEB on November 14, 2006 under file number EB-2006-0170. THESL believes that it has met the filing requirements in all relevant respects.

CORPORATE RESTRUCTURING

At the outset of OEB regulation of electric utilities, the former municipal Hydro Electric Commissions had been corporatized as part of the overall restructuring of the province's electricity sector. In Toronto Hydro's case, a parent company, Toronto Hydro Corporation ("THC") was formed which was and is 100 percent-owned by the City of Toronto.

In turn, THC holds a number of subsidiary companies. THESL was and is the principal subsidiary, accounting for the vast majority of overall assets and revenues. However, up to and for some time after "market opening" in May of 2002, THC also operated an energy retailing business through its subsidiary Toronto Hydro Energy Services Inc. ("TH Energy"). In addition, THC does operate or has operated a number of other subsidiaries, which conduct or have conducted telecommunication, street lighting, and other businesses.

At and after the initial industry restructuring, it appeared that the non-utility businesses of THC had significant growth potential and would require corresponding levels of support in terms of 'corporate' services such as legal, finance, human resources, and information technology. In addition, it was and is the case that the utility business (THESL) also required those services.

In that operational context, Toronto Hydro management took the view that unnecessary and expensive duplication of services could be avoided by maintaining a shared services model under which corporate services would be provided centrally to the subsidiaries from THC. Compliance with the Affiliate Relationships Code ("ARC") was ensured by executing Service Level Agreements ("SLAs") and adopting a fully-allocated costing approach.

Shortly after market opening, provincial policy changed and electricity retailing opportunities were substantially eliminated. TH Energy wound up its energy retailing portfolios in an orderly fashion over the next several years, and sold its water heater rental business in early 2007. The street lighting business was folded into TH Energy, which continues to develop business opportunities in distributed generation. Concurrently, the telecommunications business has expanded steadily but has evolved quite separately from the utility distribution business.

Overall, the development and prospects for the non-utility businesses operated by THC have followed a very different course than was originally anticipated and that supported the need for a shared services model. THC now envisions that THESL will continue to be its main focus.

In addition, it became apparent during the EB-2005-0421 proceeding, THESL's 2006 Electricity Distribution Rate ("EDR") Application, that the shared services model, if

continued, would be cumbersome from a regulatory efficiency and transparency point of view.

In summary, the benefits of the shared services model as it was originally implemented have declined while the costs, especially in terms of regulatory complexity, have increased. Therefore, Toronto Hydro management made the decision in 2006 to move substantially all of the formerly shared service functions from THC to THESL, and to implement revised SLAs between THESL and its affiliates to provide for the services still required by those affiliates.

On this basis, THESL provides services to affiliates in accordance with the ARC and removes from the utility accounts an allocation of the fully burdened salaries of executives and other employees who provide services to those affiliates.

MAJOR COMPONENTS OF REVENUE REQUIREMENTS

Distribution System Modernization

THESL has entered an extended period, which it forecasts will last ten or more years, during which demands for capital investment along with associated labour costs will be elevated. At all times, THESL strives to provide quality service to its customers, and THESL incurs a cost to do so. Over and above this ongoing cost of operation, THESL will experience growth in revenue requirements due to capital spending significantly in excess of depreciation and amortization; increased labour costs to both support the planned capital program and to ensure that the required skills and capability of its workforce are maintained over a period of cresting eligibility for retirement; and mandated investments in smart meters and associated assets required by the provincial smart metering initiative.

THESL has undertaken a thorough assessment of its existing physical distribution plant and has filed, as directed by the OEB in EB-2005-0421, a ten-year capital plan, titled 2007-2016 Electrical Distribution Capital Plan (the "Capital Plan") with the OEB. The Capital Plan sets out at a broad level the need for and types of capital investment that THESL must undertake in order to maintain quality service and reliability levels for customers, and identifies the magnitude of spending required for that capital program.

This Application provides information on specific capital programs and spending levels that flow from the Capital Plan for the three rate years 2008 through 2010. THESL's assessment of its distribution plant indicates the need for significant refurbishment and modernization of facilities that have been in place for several decades, in many instances for periods beyond their expected life spans. However, THESL's asset assessment is based on asset condition rather than age *per se*, and the capital plan is focused on replacing or refurbishing assets that will contribute most highly to reliability improvement. In some instances this involves substantially replacing certain categories of equipment (defined by type or vintage), such as direct-buried cable, that exhibit poor reliability.

Detailed evidence setting out THESL's proposals in this area is found at Exhibit D1, Tab 8.

Workforce Staffing

Two major factors will affect staffing needs at THESL over the test period and for several years beyond: labour needs for infrastructure renewal, and cresting eligibility for retirement as members of the baby boom generation reach retirement age. Evidence concerning THESL's workforce staffing plan is set out at Exhibit C2, Tab 1, Schedule 6.

THESL is not insulated from demographic trends, and its workforce is aging as the workforce is in many other sectors of the economy. For THESL, this issue becomes critical due in part to the need to ensure maintenance of required skills in its workforce as retirements crest over the next decade. In trades and technical areas, which are vital to providing safe, reliable service to customers, a significant period of training (four to five years) is required for new recruits to become fully certified in the job.

THESL will ensure the required transfer of knowledge and skills through two avenues: a formal trades school, which hired apprentices will attend, and in-the-field mentoring by experienced staff. In-the-field training will clearly require a period of overlap during which experienced staff can transfer their knowledge prior to their retirement. The required period of overlap is largely due to the crest in retirements; in periods of normal workforce turnover, the percentage of the workforce retiring over a given period is significantly lower and knowledge transfer can occur on a steady-state basis.

The trades school will provide the formal training foundation supporting and complementing in-the-field training. THESL's experience is that a formal training school is necessary to augment the training that is available to candidates prior to their recruitment. The school covers trades areas such as Certified Power Line Persons, Jointers, Substation Technicians, and Power Cable Persons, all of which are highly specialized. THESL also maintains a technical apprenticeship program for Design Technicians, Engineers, and Power System Controllers.

In addition to the need to replace retiring workers and transition skills to new recruits, THESL has embarked on a major program of infrastructure renewal. This program will place correspondingly increased demands on THESL's labour force, as skilled workers will be required for the planned increase in capital work as well as normal operations.

The combined forecasted effect of these factors (new hires offset by cresting retirements) is to increase the workforce FTEs (full time equivalents) by approximately 110 relative to 2007, to a peak of 1,720 in 2009. Afterward, the total workforce declines steadily to a level of 1,636 in 2012, slightly above the 2007 level of 1,610. The decline is driven by anticipated retirements, which continue to occur.

Capital Contributions to Hydro One Networks Inc. ("HONI")

Evidence concerning the HONI transmission system projects affecting the Toronto Hydro load area is found at Exhibit D2, Tab 1. In particular, theLeaside-Birch reinforcement has been identified as a priority after considering both the probability and consequences of "contingency" conditions, i.e., the loss of one or more elements of the transmission system. This project is required to maintain reliability and avoid significant service disruptions triggered by contingency conditions.

Leaside-Birch is considered to be a Connection project (as distinct from Network projects). As such, the Transmission System Code requires that capital contributions be paid by the transmission customer benefiting from the enhancements, in this case THESL. In total over the three years 2008-2010, HONI forecasts that approximately $35 million will be required for capital contributions. In general, assuming that need for a project and OEB approval are granted, capital contributions are non-discretionary on the part of the benefiting utility.

THESL anticipates that the OEB will have released its decision in the HONI EB-2006-0501 proceeding before the hearing for this Application commences. THESL has assumed that the decision in that proceeding will approve the Leaside-Birch project, and THESL has therefore included the projected capital contributions for this project in ratebase according to the projected timing of the contributions.

Smart Meters

THESL has undertaken a major commitment of resources to support the Province's Smart Meter Initiative. By the end of 2007, THESL will have installed approximately 400,000 smart meters, primarily in the residential and small general service (<50kW) classes. THESL intends to continue the smart meter rollout through to completion by year-end 2010.

Evidence concerning the details of THESL's ongoing smart meter implementation plan ("SMIP") is set out at Exhibit D1, Tab 8, Schedule 5. THESL's SMIP provides for the installation of smart meters by December 31, 2010 for existing metered customers, including demand-metered customers over 50kW, but excluding those who are or would be interval metered. This timeline is in accordance with the Province's smart meter initiative. THESL's SMIP also accounts for the introduction of smart suite metering for condominiums presently metered on a bulk basis.

In March of 2007, THESL filed an omnibus application (the "Supplementary Amended Application") requesting recovery of amounts related to CDM activities in 2005 and 2006 as well as amounts related to smart meter activities in 2006 and 2007. Specifically with respect to smart meters, the Supplementary Amended Application sought clearance of the 2006 smart meter deferral account balance; adjustment of 2007 ratebase to reflect the average net book value ("NBV") of 2006 smart meter investments through 2007, together with corresponding adjustments to base distribution rates in 2007; and revision of the smart meter rate rider for 2007 according to the OEB-supplied model and methodology.

On March 27, 2007, the OEB advised THESL that it would sever the Supplementary Amended Application to: deal with the CDM-related amounts in a separate proceeding (EB-2007-0096); determine the 2007 smart meter rate rider in conjunction with the 2007 annual rate adjustment for THESL (EB-2007-0582); and consider the remaining smart

meter-related portion of the Supplementary Amended Application in a combined proceeding including other distributors.

The OEB convened a Combined Smart Meter Proceeding (EB-2007-0063, the "Combined Proceeding") on its own motion in May 2007, and heard THESL's remaining smart meter application in that proceeding. Although the OEB required additional and updated evidence, there was no change to the relief sought by THESL in that application, other than with respect to rate implementation matters.

In this Application, THESL assumes that the relief sought in the Combined Proceeding will be granted by the OEB. In particular, this means that ratebase at year-end 2007 will include the value of the 2006 year-end smart meter investment, carried forward and amortized through 2007. In addition, THESL assumes that permanent base distribution rates will be adjusted effective November 1, 2007 to reflect the ratebase adjustment, and that rate riders pertaining to the disposition of the 2006 deferral account balance and recovery of the base distribution revenue foregone during the first six months of the 2007 rate year will be implemented effective November 1.

During the course of the Combined Proceeding, THESL advised the OEB that subject to the OEB's ruling in that proceeding, THESL intended to bring a similar application early in 2008 seeking disposition of the balance in the smart meter deferral account for 2007. With respect to smart meter investments and their inclusion in ratebase, this Application assumes the forecast year-end NBV of smart meter investments undertaken in 2007 as a component of the 2008 ratebase opening balance. THESL has included its forecast smart meter revenue requirements for the years 2008 through 2010 in this Application, and therefore believes that separate smart meter rate riders for those years are unnecessary.

Conservation and Demand Management

In accordance with Provincial policy and with OEB regulatory direction in support of that policy, THESL has largely transferred its CDM activities to operate under the auspices of the Ontario Power Authority ("OPA"). As a result, THESL is including for recovery in this Application only amounts that relate to established programs that are not presently eligible for OPA funding. Specifically, these programs are Residential Load Control and CDM Governance. Evidence concerning THESL's CDM programs for 2008 through 2010 is set out at Exhibit G1, Tab 1, Schedules 1 to 3.

The Residential Load Control program will maintain, expand, and operate residential load control infrastructure. Much of that infrastructure will have been installed prior to 2008. The system is designed to reduce residential load (such as air conditioners and pool heaters) during periods of high or critical peak demand, in response to dispatch instructions issued by the IESO through its Emergency Load Reduction Program.

It is important to maintain the installed infrastructure and corresponding peak shaving capability continuously. Interruption of the program due to loss of funding would mean abandoning an important and cost-effective source of peak shaving, and would send negative signals to participants about the necessity of and commitment to CDM.

THESL anticipates that the Residential Load Control program will have negligible impact on energy consumption, which is the basis of residential billing, since the program expressly operates to reduce peak demand rather than reduce energy consumption. Therefore the impact on distribution revenues is likely to be correspondingly minimal.

To the extent that the IESO calls on THESL to reduce peak under the Emergency Load Reduction Program, THESL will receive revenues from the IESO in payment for the load reductions achieved. THESL recognizes that revenue received under the Emergency

Load Reduction Program is properly a revenue offset for purposes of setting distribution rates. However, the amount of that revenue is negligible ($1,970 in 2006), and is not expected to materially increase over the test period.

CDM Governance is comprised of administrative functions including monitoring of compliance with OEB and THESL regulations and contractual requirements, contract execution and legal work, accounting and financial reporting, project control, program measurement and evaluation, OEB and internal reporting, and other activities necessary to the support and maintenance of THESL's CDM portfolio. As such, the costs involved in CDM governance are not directly attributable to individual programs, but are allocated across programs.

The CDM governance budget proposed in this Application has been significantly reduced from levels in prior years ($643,000 in 2006 versus $326,000 in 2008) due to the migration of the bulk of CDM to the OPA framework, and is related only to governance of existing programs, excluding programs funded by the OPA.

More generally, THESL has separated and excluded the fully allocated costs of undertaking OPA-sponsored CDM from the revenue requirement proposed in this Application. On the same basis, and in accordance with OEB policy, the revenues obtained from the OPA for CDM are also excluded from the calculation of base revenue requirements for the test years covered by this Application.

Working Capital Allowance

Over the course of OEB regulation of electric utilities, the OEB has typically allowed a Working Capital Allowance ("WCA") calculated as 15 percent of the sum of the overall cost of power and controllable distribution expenses (i.e., excluding depreciation). In EB-2005-0421, THESL requested a WCA of $307.6 million based on the application of

that formula to forecast 2006 data. The OEB accepted THESL's proposal in that case, but stated that "it would be useful to have a lead/lag study and directs the utility to file such a study prior to the next rate case."

THESL complied with the OEB's direction and commissioned Navigant Consulting Inc. to perform a lead/lag study ("the Navigant Study"). THESL filed that study with the OEB on June 20, 2007.

The Navigant Study was based on the then most recent data available, which comprised the 12-month period ending August 31, 2006. Using methodology that was accepted by the OEB in the HONI RP-2005-0020/EB-2005-0378, Navigant estimated working capital requirements (based on that data set) of $298 million, or 12.45 percent of operations, maintenance, and administration expense (OM&A) including the cost of power.

In this Application, THESL has adopted the methodology of the Navigant Study and has applied it to the forecast levels of OM&A including cost of power for the three distinct test years 2008 through 2010. The resulting WCA amounts for those years respectively are $266.4 million, $268.1 million, and $269.6 million. On average over these three years, the WCA requirements are $51 million less per year than would have been the case using the previous methodology.

Evidence concerning the proposed working capital allowances for 2008 through 2010 is set out at Exhibit D1, Tab 15, Schedules 1 to 4, and Tab 16, Schedule 1.

REVENUE REQUIREMENTS

In this Application, THESL requests approval of base distribution revenue requirements (which result after deduction of revenue offsets from service revenue requirements) for the rate years 2008 through 2010 of $498.4 million, $534.0 million, and $562.4 million

respectively. Evidence specifically addressing the derivation of the revenue requirements and revenue deficiencies is set out at Exhibit J1, Tabs 1 and 2.

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 Toronto Hydro-Electric System Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2008, May 1, 2009 and May 1, 2010.

Title of Proceeding:	An Application by **TORONTO HYDRO-ELECTRIC SYSTEM LIMITED** for an Order or Orders fixing just and reasonable distribution rates and other charges, effective May 1, 2008, May 1, 2009 and May 1, 2010.
Applicant's Name:	**TORONTO HYDRO-ELECTRIC SYSTEM LIMITED** ("THESL")
Applicant's Address:	14 Carlton Street Toronto, Ontario M5B 1K5

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APPLICATION

INTRODUCTION

THESL hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998*, as amended, for approval of its proposed electricity distribution rates and other charges for three individual and successive rate years, commencing May 1, 2008, May 1, 2009 and May 1, 2010.

THESL was one of 25 LDCs selected by the OEB for rebasing in 2008 in proceeding EB-2006-0330. Because the existing incentive regulation mechanism does not provide for the significant capital spending THESL plans to undertake over the next three years, THESL files this forward test year Application on a cost of service basis for those three years.

In preparing this Application, THESL has been guided by the OEB's November 14, 2006 *Filing Requirements for Transmission and Distribution Applications* and except where specifically identified in the Application, THESL followed the methodology set out in the OEB's 2006 Electricity Distribution Rate Handbook ("DRH"), issued on May 11, 2005.

PROPOSED DISTRIBUTION RATES AND OTHER CHARGES

The Tariffs of Rates and Charges proposed in this Application are identified in Exhibit M1, Tab 2, Schedules 2, 3 and 4 and the material being filed in support of this Application sets out THESL's approach to its 2008, 2009 and 2010 distribution rates and charges.

PROPOSED EFFECTIVE DATE OF RATE ORDER

THESL requests that the OEB make its Rate Order or Orders effective for each of forward test years May 1, 2008, May 1, 2009 and May 1, 2010.

PROPOSED DISTRIBUTION RATES AND OTHER CHARGES ARE JUST AND REASONABLE

THESL submits the adjustments to its distribution rates contained in this Application are just and reasonable on the following grounds:

1) THESL has applied generally accepted ratemaking principles to guide the development of distribution rates;
2) THESL has designed rates that collect the annual revenue requirement, begin to incrementally implement the changes suggested by the cost allocation study, and provide for a stable progression of customer rates;
3) there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by THESL;
4) this Application is authorized by Pankaj Sardana, Vice-President, Treasury, Regulatory and Rates of THESL; and
5) such further and other grounds as may be set out in Exhibit M1, Tab 1, Schedule 1 and other areas of this Application.

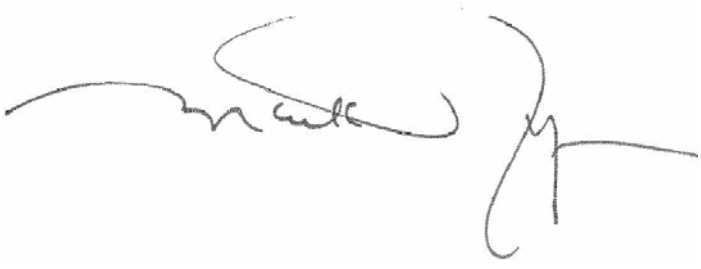
RELIEF SOUGHT

THESL applies 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, for each of the three forward test years effective May 1, 2008, May 1, 2009 and May 1, 2010.

Dated at Toronto, Ontario this 2nd day of August, 2007.

All of which is respectfully submitted,

BORDEN LADNER GERVAIS LLP



J. Mark Rodger, Counsel to Toronto Hydro-Electric System Limited

Calculation of Revenue Deficiency

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**	**Source of Data**
2	Rate Base ($M)	1,846.8	1,978.6	2,138.3	2,269.9	Exhibit D1,Tab 04, Schedule 01
3	Net Utility Income ($M)	121.9	93.7	129.2	146.9	Exhibit J1,Tab 02, Schedule 05
4	Indicated Rate of Return	6.6%	4.7%	6.0%	6.5%	Line (3) / Line (2)
5	Requested Return on Rate Base/Utility Cost of Capital	6.7%	6.8%	7.0%	7.1%	Exhibit J1, Tab 02, Schedule 02
6	Sufficiency (Deficiency) in rate of return	-0.13%	-2.04%	-0.92%	-0.59%	Line (4) - Line (5)
7	Revenue at existing rates and Other Revenue ($M)	464.1	463.0	525.9	566.5	Exhibit J1, Tab 02, Schedule 05
8	Service Revenue Requirement ($M)	467.9	524.7	555.7	586.7	Exhibit J1, Tab 02, Schedule 03
9	**Net Revenue Sufficiency (Deficiency) $M**	**-2.4**	**-40.4**	**-19.7**	**-13.5**	Line (6) * Line (2)
10	**Gross Revenue Sufficiency (Deficiency) $M**	**-3.8**	**-61.7**	**-29.8**	**-20.1**	Line (7) - Line (8)

CONTACT INFORMATION

The following is contact information for correspondence on any matter regarding this Application:

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STAKEHOLDER CONSULTATION

BACKGROUND

On June 18, 2007 THESL invited stakeholders and interested parties to attend an information session on its ten-year capital plan, filed as Exhibit D1, Tab 8, Schedule 10 of this Application. THESL's goal is to continue to provide reliable electricity to all customers in the City of Toronto. As with any type of system or technology, over time it is necessary to repair, upgrade or replace equipment. Much of THESL's existing plant is nearing the end of its life expectancy and this ten-year capital plan is being implemented over 2007-2016 to improve service and reliability, reduce the frequency of power outages and accommodate future growth and electricity service demands.

OBJECTIVE

THESL's stakeholder information session on its ten-year capital plan was hosted on July 10, 2007. The objective of the information session was to provide attendees with a high level description of THESL's capital investment plans which are aimed at addressing deteriorating asset performance and aging infrastructure over the next ten years. Parties were invited to ask questions and to seek further clarification on the material presented.

ATTENDANCE

Guests at the information session included key stakeholders and interested parties, namely, parties who have previously or historically intervened in THESL's rate cases before the Board and parties otherwise reasonably thought to have an interest in THESL's long term electrical distribution capital plan which forecasts annual budget amounts to sustain and develop THESL capital investments over a ten-year horizon. THESL believes that those invited were representative of the interests of the majority of its stakeholders.

PREVIOUS DIRECTIONS AND UNDERTAKINGS

DIRECTIONS FROM 2006 EDR DECISION

The following Directions were issued to THESL by the OEB in its April 12, 2006 Decision with Reasons in EB-2005-0421:

1) file compensation studies as specified in the Decision (Section 3.1);
2) file a lead-lag study prior to the next rate case (Section 4.1);
3) conduct proper cost allocation study with respect to corporate overhead cost (Section 3.2);
4) file comprehensive capital budget prior to the next rate case (Section 4.2);
5) ensure that at least one-third of Toronto Hydro's Board of Directors is independent from affiliates as of July 1, 2006 in accordance with Compliance Bulletin 200601 (Section 6.5);
6) any dividend payout by Toronto Hydro to an affiliate be approved by a majority of the independent directors (Section 6.4); and
7) file a proposal to reduce [THESL's] line losses by at least 5%. (Section 3.4).

Actions taken by THESL in response to the OEB's Directions are set out below.

1) Compensation Studies

Compensation and Benefits Competitiveness, dated May 31, 2007 and prepared by Mercer Human Resources Consulting, was filed with the OEB on June 20, 2007. This Report is referred to in Exhibit C2, Tab 1, Schedule 3 of the current Application.

2) Lead-Lag Study

A *Report on Lead Lag Study and Working Capital Results using 2005 Expense Levels*, dated December 4, 2006 and prepared by Navigant Consulting Inc., was

filed with the OEB on June 20, 2007 and is also filed in the current Application as Exhibit D1, Tab 15, Schedule 1.

3) Cost Allocation Study with respect to Corporate Overhead Cost

A *Report on Affiliate Transactions Regulatory Compliance: Methodology and Implementation*, dated June 2007, was prepared with the support of Key Willow Consulting and is filed with this Application as Exhibit Q1, Tab 1, Schedule 1.

4) Capital Budget

On February 9, 2007 THESL filed with the OEB a *Distribution Asset Condition Assessment* prepared for THESL by Kinectrics Inc. and a long term electrical distribution capital plan. The *2007-2016 Electrical Distribution Capital Plan* forecasts annual budget amounts to sustain and develop capital investments over a ten-year horizon. These documents are filed with this Application as Exhibit D1, Tab 8, Schedule 9 and Exhibit D1, Tab 8, Schedule 10, respectively.

5) One-third Director Independence from Affiliates

Effective August 24, 2006, one-third of THESL's Board of Directors was independent from any affiliate. THESL has previously reported to the OEB on this matter in its Q1, 2007 RRR Affiliate Relationships Code self-certification filing.

6) Dividend Payout by THESL to an Affiliate Approved by a Majority of the Independent Directors of THESL

THESL has commenced a court action challenging the OEB's authority to impose this requirement on the THESL Board of Directors.

7) Line Loss Proposal

THESL's *A Plan to Reduce Line Losses by 5%* was filed with the OEB on July 11, 2006.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

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

EB-2007-0582

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

SERVICE CLASSIFICATIONS

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 4,999 kW

<u>50-1000 kW Non-Interval Meter:</u>
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 and with a non-interval meter. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

<u>50-1000 kW Interval Meter:</u>
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 and with an interval meter. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

<u>Intermediate Use between 1000-5000 kW:</u>
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.

Large Use

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.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

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Unmetered Scattered Load
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.

Standby Power
These classifications refer to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting
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.

MONTHLY RATES AND CHARGES

Residential

Service Charge (includes Smart Meter rate adder of $0.68)	$	12.68 per 30 days
Distribution Volumetric Rate	$/kWh	0.0155
Regulatory Asset Recovery	$/kWh	0.0032
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

General Service Less Than 50 kW

Service Charge (includes Smart Meter rate adder of $0.68)	$	16.75 per 30 days
Distribution Volumetric Rate	$/kWh	0.0185
Regulatory Asset Recovery	$/kWh	0.0015
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

General Service 50 to 4,999 kW

Non Interval Meters – 50 to 1,000 kW		
Service Charge (includes Smart Meter rate adder of $0.68)	$	26.26 per 30 days
Distribution Volumetric Rate	$/kVA	4.98 per 30 days
Regulatory Asset Recovery	$/kVA	0.31 per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.23 per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.68 per 30 days
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
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Interval Meters – 50 to 1,000 kW		
Service Charge (includes Smart Meter rate adder of $0.68)	$	26.50 per 30 days
Distribution Volumetric Rate	$/kVA	4.98 per 30 days
Regulatory Asset Recovery	$/kVA	0.09 per 30 days
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.27 per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71 per 30 days
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days
1,000 to 5,000 kW		
Service Charge (includes Smart Meter rate adder of $0.68)	$	718.10 per 30 days
Distribution Volumetric Rate	$/kVA	4.16 per 30 days
Regulatory Asset Recovery	$/kVA	0.07 per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.40 per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77 per 30 days
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

Large Use

Service Charge (includes Smart Meter rate adder of $0.68)	$	2,758.98 per 30 days
Distribution Volumetric Rate	$/kVA	3.55 per 30 days
Regulatory Asset Recovery	$/kVA	0.07 per 30 days
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.50 per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80 per 30 days
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

Standby Power – APPROVED ON AN INTERIM BASIS

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

Service Charge	$	197.91 per 30 days
Distribution Volumetric Rate:		
General Service 50 – 1,000 kW	$/kVA	4.98 per 30 days
General Service 1,000 – 5,000 kW	$/kVA	4.16 per 30 days
Large Use	$/kVA	3.55 per 30 days

Unmetered Scattered Load

Monthly Service Charge	$	1.99 per 30 days
Service Charge (per connection)	$	0.29 per 30 days
Distribution Volumetric Rate	$/kWh	0.0180
Regulatory Asset Recovery	$/kWh	0.0014
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

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

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Street Lighting

Service Charge (per connection)	$	0.26 per 30 days
Distribution Volumetric Rate	$/kVA	3.60 per 30 days
Regulatory Asset Recovery	$/kVA	0.08 per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.75 per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03 per 30 days
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Debt Retirement Charge	$/kWh	0.007
Standard Supply Service – Administrative Charge (if applicable)	$	0.25 per 30 days

Specific Service Charges

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)
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)

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

EB-2007-0582

LOSS FACTORS

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	0.99
(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
(F) Customer greater than 5,000 kW (A)*(F)	1.0085

RETAIL SERVICE CHARGES

These are charges for service 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

Charge to a retailer:

- standard charge (one-time charge) of $100 per agreement, per retailer.
- monthly fixed charge of $20 per month, per retailer.
- monthly variable charge of $0.50 per month, per customer

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per month, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per month, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

- request fee of $0.25 per request, regardless of whether or not the STR can be processed.
- processing fee of $0.50 per request, applied to the requesting party if the request is processed.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000kW

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.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge	$	14.85	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0173	
Regulatory Asset Recovery	$/kWh	-0.0010	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge	$	19.37	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0210	
Regulatory Asset Recovery	$/kWh	-0.0010	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	

90	Rural Rate Protection Charge	$/kWh	0.0010	
91	Debt Retirement Charge	$/kWh	0.0070	
92	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
93				
94	**General Service 50 to 5000 kW**			
95				
96	***50 to 1000 kW***			
97	Service Charge	$	29.78	per 30 days
98	Distribution Volumetric Rate (with LV Charges)	$/kVA	5.40	per 30 days
99	Regulatory Asset Recovery	$/kVA	-0.32	per 30 days
100	Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
101	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
102	Wholesale Market Service Rate	$/kWh	0.0052	
103	Rural Rate Protection Charge	$/kWh	0.0010	
104	Debt Retirement Charge	$/kWh	0.0070	
105	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
106				
107	***1000 to 5000 kW***			
108	Service Charge	$	725.80	per 30 days
109	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.52	per 30 days
110	Regulatory Asset Recovery	$/kVA	-0.36	per 30 days
111	Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
112	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
113	Wholesale Market Service Rate	$/kWh	0.0052	
114	Rural Rate Protection Charge	$/kWh	0.0010	
115	Debt Retirement Charge	$/kWh	0.0070	
116	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
117				
118	**Large Use**			
119	Service Charge	$	2,883.81	per 30 days
120	Distribution Volumetric Rate (with LV Charges)	$/kVA	3.97	per 30 days
121	Regulatory Asset Recovery	$/kVA	-0.47	per 30 days
122	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
123	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
124	Wholesale Market Service Rate	$/kWh	0.0052	
125	Rural Rate Protection Charge	$/kWh	0.0010	
126	Debt Retirement Charge	$/kWh	0.0070	
127	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
128				
129	**Standby Power - APPROVED ON AN INTERIM BASIS**			
130				
131	Standby Administration Charge	$	197.91	per 30 days
132				
133	***Standby Charge – for a month where standby power is not provided. The volumetric distribution rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
134	General Service 50 – 1000 kW	$/kVA	5.40	per 30 days
135	General Service 1000 – 5000 kW	$/kVA	4.52	per 30 days
136	Large Use	$/kVA	3.97	per 30 days
137				

Unmetered Scattered Load

Service Charge	$	2.96	per 30 days
Connection Charge (per connection)	$	0.33	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0259	
Regulatory Asset Recovery	$/kWh	-0.0009	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Street Lighting

Service Charge (per connection)	$	0.66	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	8.75	per 30 days
Regulatory Asset Recovery	$/kVA	-0.30	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Specific Service Charges

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
Disconnect/Reconnect Charges for non-payment of account - 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

185	Disconnect/Reconnect at Pole – After Regular Hours	$	415.00	
186				
187	Specific Charge for Access to the Power Poles – per pole/year	$	22.35	
188				
189	***Allowances***			
190				
191	Transformer Allowance for Ownership	$/kVA	(0.62)	per 30 days
192	Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	
193				
194	**LOSS FACTORS**			
195	Billing Determinant:			
196	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 Other Regulated Rates.			
197				
198	(A) Primary Metering Adjustment		0.9900	
199				
200	(B) Supply Facilities Loss Factor		1.0045	
201				
202	***Distribution Loss Factors***			
203	(C) Customer less than 5,000 kW		1.0330	
204	(D) Customer 5,000 kW or greater		1.0141	
205				
206	**Total Loss Factors**			
207				
208	***Secondary Metered Customers***			
209	(E) Customer less than 5,000 kW(B)*(C)		1.0376	
210	(F) Customer 5,000 kW or greater(B)*(D)		1.0187	
211				
212	***Primary metered customers***			
213	(G) Customer less than 5,000 kW (A)*(E)		1.0272	
214	(F) Customer 5,000 kW or greater (A)*(F)		1.0085	
215				
216	RETAIL SERVICE CHARGES			
217				
218	These are charges for service provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.			
219				
220	Establishing Service Agreements			
221				
222	Charge to a retailer:			
223				
224	1) standard charge (one-time charge) of $100 per agreement, per retailer.			
225	2) monthly fixed charge of $20 per 30 days, per retailer.			
226	3) monthly variable charge of $0.50 per 30 days, per customer			
227				

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per 30 days, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per 30 days, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulatec Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000kW

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.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge	$	16.85	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0174	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge	$	21.44	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0218	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	

90	Rural Rate Protection Charge	$/kWh	0.0010	
91	Debt Retirement Charge	$/kWh	0.0070	
92	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
93				
94	**General Service 50 to 5000 kW**			
95				
96	***50 to 1000 kW***			
97	Service Charge	$	32.69	per 30 days
98	Distribution Volumetric Rate (with LV Charges)	$/kVA	5.58	per 30 days
99	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
100	Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
101	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
102	Wholesale Market Service Rate	$/kWh	0.0052	
103	Rural Rate Protection Charge	$/kWh	0.0010	
104	Debt Retirement Charge	$/kWh	0.0070	
105	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
106				
107	***1000 to 5000 kW***			
108	Service Charge	$	705.33	per 30 days
109	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.69	per 30 days
110	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
111	Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
112	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
113	Wholesale Market Service Rate	$/kWh	0.0052	
114	Rural Rate Protection Charge	$/kWh	0.0010	
115	Debt Retirement Charge	$/kWh	0.0070	
116	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
117				
118	**Large Use**			
119	Service Charge	$	2,639.01	per 30 days
120	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.20	per 30 days
121	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
122	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
123	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
124	Wholesale Market Service Rate	$/kWh	0.0052	
125	Rural Rate Protection Charge	$/kWh	0.0010	
126	Debt Retirement Charge	$/kWh	0.0070	
127	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
128				
129	**Standby Power - APPROVED ON AN INTERIM BASIS**			
130				
131	Standby Administration Charge	$	197.91	per 30 days
132				
133	***Standby Charge – for a month where standby power is not provided. The volumetric distribution rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
134	General Service 50 – 1000 kW	$/kVA	5.58	per 30 days
135	General Service 1000 – 5000 kW	$/kVA	4.69	per 30 days
136	Large Use	$/kVA	4.20	per 30 days
137				

Unmetered Scattered Load

Service Charge	$	3.42	per 30 days
Connection Charge (per connection)	$	0.35	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0299	
Regulatory Asset Recovery	$/kWh	0.00	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Street Lighting

Service Charge (per connection)	$	0.89	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	10.82	per 30 days
Regulatory Asset Recovery	$/kVA	0.00	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Specific Service Charges

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
Disconnect/Reconnect Charges for non-payment of account - 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

184	Disconnect/Reconnect at Pole – During Regular Hours	$	185.00
185	Disconnect/Reconnect at Pole – After Regular Hours	$	415.00
186			
187	Specific Charge for Access to the Power Poles – per pole/year	$	22.35
188			
189	***Allowances***		
190			
191	Transformer Allowance for Ownership	$/kVA	(0.62) per 30 days
192	Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)
193			
194	**LOSS FACTORS**		
195	Billing Determinant:		
196	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 Other Regulated Rates.		
197			
198	(A) Primary Metering Adjustment		0.9900
199			
200	(B) Supply Facilities Loss Factor		1.0045
201			
202	***Distribution Loss Factors***		
203	(C) Customer less than 5,000 kW		1.0330
204	(D) Customer 5,000 kW or greater		1.0141
205			
206	**Total Loss Factors**		
207			
208	***Secondary Metered Customers***		
209	(E) Customer less than 5,000 kW(B)*(C)		1.0376
210	(F) Customer 5,000 kW or greater (B)*(D)		1.0187
211			
212	***Primary metered customers***		
213	(G) Customer less than 5,000 kW (A)*(E)		1.0272
214	(F) Customer 5,000 kW or greater (A)*(F)		1.0085
215			
216	RETAIL SERVICE CHARGES		
217			
218	These are charges for service provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.		
219			
220	Establishing Service Agreements		
221			
222	Charge to a retailer:		
223			
224	1) standard charge (one-time charge) of $100 per agreement, per retailer.		
225	2) monthly fixed charge of $20 per 30 days, per retailer.		
226	3) monthly variable charge of $0.50 per 30 days, per customer		
227			

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per 30 days, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per 30 days, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFFS OF RATES AND CHARGES
Effective May 1, 2010

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2010 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2010 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000kW

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.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge	$	18.14	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0177	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge	$	22.84	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0227	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	

89	Wholesale Market Service Rate	$/kWh	0.0052	
90	Rural Rate Protection Charge	$/kWh	0.0010	
91	Debt Retirement Charge	$/kWh	0.0070	
92	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
93				
94	**General Service 50 to 5000 kW**			
95				
96	***50 to 1000 kW***			
97	Service Charge	$	34.01	per 30 days
98	Distribution Volumetric Rate (with LV Charges)	$/kVA	5.63	per 30 days
99	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
100	Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
101	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
102	Wholesale Market Service Rate	$/kWh	0.0052	
103	Rural Rate Protection Charge	$/kWh	0.0010	
104	Debt Retirement Charge	$/kWh	0.0070	
105	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
106				
107	***1000 to 5000 kW***			
108	Service Charge	$	691.11	per 30 days
109	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.75	per 30 days
110	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
111	Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
112	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
113	Wholesale Market Service Rate	$/kWh	0.0052	
114	Rural Rate Protection Charge	$/kWh	0.0010	
115	Debt Retirement Charge	$/kWh	0.0070	
116	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
117				
118	**Large Use**			
119	Service Charge	$	2,277.32	per 30 days
120	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.36	per 30 days
121	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
122	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
123	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
124	Wholesale Market Service Rate	$/kWh	0.0052	
125	Rural Rate Protection Charge	$/kWh	0.0010	
126	Debt Retirement Charge	$/kWh	0.0070	
127	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
128				
129	**Standby Power - APPROVED ON AN INTERIM BASIS**			
130				
131	Standby Administration Charge	$	197.91	per 30 days
132				
133	***Standby Charge – for a month where standby power is not provided. The volumetric distribution rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
134	General Service 50 – 1000 kW	$/kVA	5.63	per 30 days

135	General Service 1,000 – 5000 kW	$/kVA	4.75	per 30 days
136	Large Use	$/kVA	4.36	per 30 days
137				
138	**Unmetered Scattered Load**			
139	Service Charge	$	3.74	per 30 days
140	Connection Charge (per connection)	$	0.37	per 30 days
141	Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0336	
142	Regulatory Asset Recovery	$/kWh	0.00	
143	Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
144	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
145	Wholesale Market Service Rate	$/kWh	0.0052	
146	Rural Rate Protection Charge	$/kWh	0.0010	
147	Debt Retirement Charge	$/kWh	0.0070	
148	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
149				
150	**Street Lighting**			
151	Service Charge (per connection)	$	1.12	per 30 days
152	Distribution Volumetric Rate (with LV Charges)	$/kVA	13.10	per 30 days
153	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
154	Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
155	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
156	Wholesale Market Service Rate	$/kWh	0.0052	
157	Rural Rate Protection Charge	$/kWh	0.0010	
158	Debt Retirement Charge	$/kWh	0.0070	
159	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
160				
161	**Specific Service Charges**			
162				
163	***Customer Administration***			
164				
165	Duplicate Invoices for Previous Billing	$	15.00	
166	Easement Letter	$	15.00	
167	Income Tax Letter	$	15.00	
168	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	
169	Returned Cheque (plus bank charges)	$	15.00	
170	Special Meter Reads	$	30.00	
171	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	
172				
173	***Non-Payment of Account***			
174				
175	Late Payment - per month	%	1.50	
176	Late Payment - per annum	%	19.56	
177	Collection of Account Charge – No Disconnection	$	30.00	
178	Disconnect/Reconnect Charges for non-payment of account - At Meter During Regular Hours	$	65.00	
179	Disconnect/Reconnect Charges for non-payment of account - 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

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)

LOSS FACTORS

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 Other Regulated 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 5,000 kW or greater (B)*(D)	1.0187

Primary metered customers

(G) Customer less than 5,000 kW (A)*(E)	1.0272
(F) Customer 5,000 kW or greater (A)*(F)	1.0085

RETAIL SERVICE CHARGES

These are charges for service 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

Charge to a retailer:

1) standard charge (one-time charge) of $100 per agreement, per retailer.
2) monthly fixed charge of $20 per 30 days, per retailer.

3) monthly variable charge of $0.50 per 30 days, per customer

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per 30 days, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per 30 days, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

Summary Bill Comparisons

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Monthly Bill ($)				Annual Change			
1	**Rate Class**	**2007**	**2008**	**2009**	**2010**	**2008**	**2009**	**2010**	**Average 2007-2010**
2									
3	Residential (1000 kWh)								
4	Distribution	27.50	32.15	34.25	35.84	16.9%	6.5%	4.6%	9.2%
5	Rate Rider	3.88	(1.00)	0.00	0.00	-125.8%	-100.0%	0.0%	-100.0%
6	Distribution and Rate Rider	31.38	31.15	34.25	35.84	-0.7%	10.0%	4.6%	4.5%
7	Total Bill	112.78	112.55	115.65	117.24	-0.2%	2.8%	1.4%	1.3%
8									
9	General Service <50 kW (10,000 kWh)								
10	Distribution	201.07	229.37	239.44	249.84	14.1%	4.4%	4.3%	7.5%
11	Rate Rider	15.68	(10.00)	0.00	0.00	-163.8%	-100.0%	0.0%	-100.0%
12	Distribution and Rate Rider	216.75	219.37	239.44	249.84	1.2%	9.1%	4.3%	4.8%
13	Total Bill	1,094.77	1,097.39	1,117.46	1,127.86	0.2%	1.8%	0.9%	1.0%
14									
15	GS 50-999.9 kW Interval Metered (500 kW, 556 kVA and 200,000 kWh)								
16	Distribution	2,792.49	3,029.78	3,132.69	3,161.79	8.5%	3.4%	0.9%	4.2%
17	Rate Rider	50.68	(177.78)	0.00	0.00	-450.8%	-100.0%	0.0%	-100.0%
18	Distribution and Rate Rider	2,843.17	2,852.00	3,132.69	3,161.79	0.3%	9.8%	0.9%	3.6%
19	Total Bill	20,379.53	20,388.37	20,669.05	20,698.15	0.0%	1.4%	0.1%	0.5%
20									
21	1000-4999.9 kW (2,000 kW, 2,222 kVA, and 1,000,000 kWh)								
22	Distribution	9,961.86	10,770.24	11,127.55	11,246.67	8.1%	3.3%	1.1%	4.1%
23	Rate Rider	156.24	(800.00)	0.00	0.00	-612.0%	-100.0%	0.0%	-100.0%
24	Distribution and Rate Rider	10,118.10	9,970.24	11,127.55	11,246.67	-1.5%	11.6%	1.1%	3.6%
25	Total Bill	96,215.92	96,068.06	97,225.37	97,344.49	-0.2%	1.2%	0.1%	0.4%
26									
27	Large Use (5,000 kW, 5,556 kVA and 2,500,000 kWh)								
28	Distribution	22,480.52	24,939.37	25,972.34	26,499.54	10.9%	4.1%	2.0%	5.6%
29	Rate Rider	389.57	(2,611.11)	0.00	0.00	-770.3%	-100.0%	0.0%	-100.0%
30	Distribution and Rate Rider	22,870.09	22,328.25	25,972.34	26,499.54	-2.4%	16.3%	2.0%	5.0%
31	Total Bill	235,551.94	235,010.10	238,654.19	239,181.39	-0.2%	1.6%	0.2%	0.5%
32									
33	Streetlighting (1 kW and 365 kWh)								
34	Distribution	3.86	9.41	11.71	14.22	143.8%	24.4%	21.4%	54.4%
35	Rate Rider	0.08	(0.30)	0.00	0.00	-475.0%	-100.0%	0.0%	-100.0%
36	Distribution and Rate Rider	3.94	9.11	11.71	14.22	131.2%	28.5%	21.4%	53.4%
37	Total Bill	33.95	39.12	41.72	44.23	15.2%	6.6%	6.0%	9.2%
38									
39	Scattered Load (1 kW and 365 kWh)								
40	Distribution	8.85	12.74	14.68	16.37	44.0%	15.2%	11.5%	22.8%
41	Rate Rider	0.51	(0.33)	0.00	0.00	-164.3%	-100.0%	0.0%	-100.0%
42	Distribution and Rate Rider	9.36	12.42	14.68	16.37	32.6%	18.3%	11.5%	20.5%
43	Total Bill	38.49	41.54	43.81	45.50	7.9%	5.5%	3.9%	5.7%

WITNESS PANELS

PANEL NUMBER	EXHIBITS
1	A1 – Application Summary B1 – Corporate Overview C1 – Policy
2	C2 – Aggregated Cost Categories
3	D1, D2 – Capital/Rate Base
4	E1 – Cost of Capital
5	F1, F2 – Distribution Expenses H1 – PILS/Tax
6	G1 – CDM
7	I1 – Revenue Offsets J1 – Revenue Requirement K1 – Loads, Customers and Revenue
8	L1 – Cost Allocation M1 – Rate Design N1 – Other Regulated Charges O1 – Bill Impacts
9	Q1 – Shared Services Study

CURRICULUM VITAE OF
Darryl James Seal

EDUCATION:

- Master of Arts, Economics, University of Waterloo, 1989
- Bachelor of Arts (Honours), Economics, Queen's University, Kingston, 1987

BUSINESS EXPERIENCE:

- Toronto Hydro Corporation (2006-Present)
  - Manager, Rates & Treasury Operations
- Institutional Energy Analysis Inc. (2005-2006, 2003-2004)
  - Principal Consultant
- SPI Group Inc. (2004-2005)
  - Project Manager
- Algorithmics Inc. (2001-2002)
  - Product Manager
- Ontario Independent Electricity System Operator (IESO) (1999-2001)
  - Consulting Economist
- Enbridge Consumers Gas (1989-1999)
  - Manager, Economic Studies Department (1996-1999)
  - Supervisor, Economics (1994-1996)
  - Senior Economic Analyst (1992-1994)
  - Economic Analyst (1989-1992)
- Ontario Ministry of Treasury and Economics (1988)
  - Junior Economist
- University of Waterloo (1988-1989)
  - Teaching Assistant

REGULATORY APPEARANCES:

- Ontario Energy Board
  - EB-2005-0421
  - EB-2005-0529
  - RP-2004-0213
  - E.B.R.O 497-01
- Quebec Regie de l'energie
  - D-2006-158
- New York Public Service Commission
  - 97-G-0409

INDUSTRY ASSOCIATIONS & COMMITTEES

- Member, Toronto Association for Business Economics, 1989-Present
- Chair, Board of Directors, Consumers' Gas Employees Credit Union, 1996-1999
- Chair, Canadian Gas Association Economics and Statistics Committee, 1997-1998

CURRICULUM VITAE OF
Richard Y. Lü, ROH, CRSP, MD, MHSc, MSc, MBA

EDUCATION:

2003	***Master of Business Administration***
	Rotman, University of Toronto, Toronto, Ontario, Canada
1999	***Graduate, Darden Executive Education Program***
	Graduate School of Business Administration, University of Virginia, Virginia, USA
1994	***Master of Health Science (Occupational Hygiene)***
	University of Toronto, Toronto, Ontario, Canada
1988	***Master of Science (Biochemistry)***
	Tongji Medical University, Wuhan, Hubei, China
1985	***Doctorate of Medicine (Occupational Medicine)***
	Tongji Medical University, Wuhan, Hubei, China

PROFESSIONAL REGISTRATIONS:

- Member, CDM Caucus, the EDA, Ontario, 2006 –
- Member, CDM Steering Committee, the CLD, Ontario, 2004 –
- Registered Occupational Hygienist (ROH), #497, Canada
- Canadian Registered Safety Professional (CRSP), #99-1354, Canada
- Member, CSA Technical Committee on OH&S Management System, 2004 – 2006
- Director, Canadian Energy Efficiency Alliance, 2002 – 2003
- Director, Occupational Hygiene Association of Ontario, 1999 – 2002
- Member, AGA Environment and Health & Safety Committees, 1999 – 2001

- Member, CGA Safety Initiative Task Force， 1999 – 2001

EXPERIENCE:

Jan. 2002 – Present	Toronto Hydro Corporation: Chief Conservation Officer, Vice President – EHS
Jun. 1999 – Jan. 2002	Enbridge Gas Distribution: Manager – EHS
Nov. 1996 – May 1999	Husky Injection Molding Systems Ltd.**:** Specialist – EHS
Jan. 1995 – Oct. 1996	Dillon Consulting Ltd.: Consultant – Environment, Health & Safety (EHS)
Feb. 1990 – Dec. 1994	Hospital for Sick Children: Post-Doctoral Research Fellow, University of Toronto
July 1988 - Feb. 1990	Chinese Academy of Preventive Medicine, Project Manager – Occupational Medicine National Cancer Institute, NIH, and WESTAT Inc, Maryland, USA

REGULATORY APPEARANCES:

Witness at the following Ontario Energy Board Proceedings:

- EB-2007-0096 – Toronto Hydro-Electric System Limited Application for Recovery of Amounts relating to CDM Activities, Technical Conference
- EB-2006-0145 – Toronto Hydro-Electric System Limited Application for its 2006 Summer Challenge 10/10 Program
- RP-2004-0203 / EB-2004-0485 – Toronto Hydro-Electric System Limited Application for its Conservation and Demand Management Plan

CURRICULUM VITAE OF
Ave Lethbridge, MSOD, CHRM

EDUCATION:

- Masters of Science Organization Development, University of Pepperdine, CA, August 2001.
- Strategic Organizational Change Executive Program, University of Toronto, Rotman School of Business, 1998
- Designation in Advance Human Resource Management, University of Toronto, Rotman School of Business, 1996 - HRPAO – CHRP/ CHRM, 1994

PROFESSIONAL REGISTRATIONS:

Human Resources Professional Association of Ontario

BUSINESS EXPERIENCE:

November 2004 – Present	Toronto Hydro Corporation Vice-President Organizational Effectiveness (HR, Org Development & Performance and Project Management)
September 2002 – October 2004	Toronto Hydro Corporation Vice-President Organizational Development
March 2000 - August 2002	Toronto Hydro Corporation Director Organizational Development & Leader of Business Transformation Change Management
January 1998 – February 2000	Toronto Hydro Corporation Director Organizational Development
1990 – December 1997	Scarborough Public Utilities Manager Human Resources

1987 – 1990	HR Consultant/Assistant Manager
1981- 1987	Great West Gas (Formally Inter City Gas)
	Human Resources Analyst/ Consultant

CURRICULUM VITAE OF
Dino Priore

EDUCATION:

- MBA Degree, with distinction
  York University, Schulich Business School, 1992
- B.A.Sc. Degree in Electrical Engineering, with honour standing
  University of Toronto, 1986

BUSINESS EXPERIENCE:

- Vice President, Distribution Services, Toronto Hydro, 2006 to present
- Senior Manager (GIS Project), Toronto Hydro, 2005 to 2006
- Senior Manager, Distribution Projects, Toronto Hydro, 2001 to 2005
- IT Project Leader, Business Transformation, Toronto Hydro, 1998 to 2001
- Manager, Engineering Design, North York Hydro, 1990 to 1998
- Project Engineer, North York Hydro, 1986 to 1990

PROFESSIONAL REGISTRATIONS:

- Professional Engineers of Ontario

REGULATORY APPEARANCES:

- None

AWARDS and RECOGNITION:

- R&D Committee Award from the Municipal Electric Association
- University of Toronto JW Billes Admission Scholarship
- University of Toronto JE McAllister Summer Research Fellowship
- University of Toronto Life Sciences Committee Summer Research Fellowship

- Government of Canada NSERC Research Award
- York University Marsh & McLennan MBA Scholarship
- Dean's Honour List
- 95th percentile on the GMAT

INDUSTRY ASSOCIATIONS & COMMITTEES:

- Geospatial Information and Technology Association (GITA)

CURRICULUM VITAE OF
Jean-Sebastien Couillard, CA

EDUCATION:

- September 1996, Canadian Institute of Chartered Accountants, Chartered Accountant Designation
- December 1994, École des Hautes Études Commerciales of Montreal, Bachelor in Business and Administration

PROFESSIONAL REGISTRATIONS:

- Canadian Institute of Charted Accountants (CICA)

BUSINESS EXPERIENCE

- November 2004 – Present, Toronto Hydro Corporation, Chief Financial Officer
- April 2004 – November 2004, Toronto Hydro Corporation, Vice-President Finance
- March 2002 – March 2004, Toronto Hydro Energy Services, Vice-President Finance and Operations
- March 2001 – February 2002, Group Telecom, Director of Business Operations – Central Region
- January 2000 – February 2001, Group Telecom, Director of Corporate Financial Analysis
- May 1993 – March 1999, Ernst & Young LLP, Audit Manager and Supervising Senior Auditor

REGULATORY APPEARANCES:

Witness at the following Ontario Energy Board proceedings:

- September 2004 - Transition Cost Proceeding
- THESL 2006 Electricity Distribution Rates Hearing, EB-2005-0421

CURRICULUM VITAE OF
Susan Davidson

EDUCATION:

- ***Bishops University,*** Executive Development Program

BUSINESS EXPERIENCE:

- December 1999 – Present, Toronto Hydro Corporation, VP-SVP, Customer Services
- 1996, 1998, Manulife Financial, Assistant Vice President, Call Center
- 1985-1996, Crown Life Insurance Company, Assistant Vice President, Customer Care

REGULATORY APPEARANCES:

Witness at the following Ontario Energy Board proceedings:

- RP-2000-0021 – Toronto Hydro Distribution Rates

CURRICULUM VITAE OF
Robert King

EDUCATION:

- Professional Engineer Accreditation Program, P.E.O.

BUSINESS EXPERIENCE:

- TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

  2006 – Present, Chief Operating Office

  2002 – 2006, Senoir Vice-President – Distribution Services

  1999 – 2002, Vice-President – Business Transformation

  1998 – 1999, Senior Manager – North-West District, Distribution Services

  1997 – 1998, Construction Manager – Etobicoke Office
- SCARBOROUGH P.U.C.

  1995 – 1997, Manager – Standards & Maintenance

  1993 – 1995, Leader - Business Enterprises

  1990 – 1993, Manager – Construction & Maintenance
- PICKERING HYDRO

  1989 – 1990, Director of Operations
- ONTARIO HYDRO

  1986 – 1989, Distribution Lines Supervisor, Central Region

  1981 – 1986 Project Technician, Transmission Lines, Head Office

  1975 – 1981, Journeyman Lineman, Central Region Travelling Crew

PROFESSIONAL REGISTRATIONS:

- Professional Engineers of Ontario

INDUSTRY ASSOCIATIONS $ & COMMITTEES:

- Electrical & Utilities Safety Association of Ontario (E&USA) Board of Directors

CURRICULUM VITAE OF
Pankaj Sardana, MA (Econ), CFA

EDUCATION:

- ***Chartered Financial Analyst*** (1998), CFA Institute, Charlottesville, Virginia
- **Canadian Securities Course** (1995)
- ***University of Waterloo***, Waterloo, Ontario (1985), Master of Arts, Applied Economics
- ***University of Waterloo***, Waterloo, Ontario (1982), Bachelor of Arts (Honours Economics)

PROFESSIONAL REGISTRATIONS:

- ***Treasury Management Association of Canada (TMAC)***
- ***Toronto CFA Society***
- ***TABE***

BUSINESS EXPERIENCE:

January 2002 – Present	Toronto Hydro Corporation
	Vice-President, Treasurer
August 1998 – December 2001	Independent Electricity System Operator
	Assistant Treasurer
April 1989 – 1998	Ontario Hydro
	Senior Rate Economist; Senior Analyst (Central Market Operations)
April 1987 – March 1989	Ontario Hydro
	Economist, Economics and Load Forecasts Division
January 1986 – April 1987	Ontario Ministry of Energy
	Economist, Energy Policy Branch

September 1985 – December 1985 Consumers' Gas Company
Economist

REGULATORY APPEARANCES:

Witness at the following Ontario Energy Board proceedings:

- EB-2006-0145 Toronto Hydro-Electric System Limited Application for its 2006 Summer Challenge (10/10) Program
- RP-2000-0021 Toronto Hydro-Electric System Limited Distribution Rates
- HR-23 – Ontario Hydro Wholesale Rates, 1994/1995

CURRICULUM VITAE OF
Colin J. McLorg

EDUCATION:

- 1986, Master of Arts, Economics, University of Waterloo
- 1983, Bachelor of Arts, Honours Economics (Philosophy Minor), University of Waterloo

BUSINESS EXPERIENCE:

- 2006 – Present, Toronto Hydro-Electric System Limited
  August 2006 – Present: Manager, Regulatory Affairs (Regulatory Affairs)

- 2005 – 2006, Ontario Energy Board
  July 2005 – July 2006: Manager, Electricity Rate Applications (Applications)

- 2000 – 2005, Toronto Hydro Corporation
  January 2000 – July 2005: Regulatory Specialist; Senior Advisor (Regulatory Affairs)

- 1989 – 2000, Enbridge Consumers Gas
  July 1997 - January 2000: Senior Analyst; Manager, Business Intelligence (Strategic Planning)
  July 1995 - July 1997: Manager, Rate Design (Regulatory Affairs)
  1992 - 1995: Senior Integrated Resource Planning Analyst (Regulatory Studies)
  1989 - 1992: Conservation Analyst, Senior Conservation Analyst (Economic Studies)

- 1987 – 1989, ICG Utilities (Ontario) Ltd.
  1987 - 1989: Intermediate Regulatory Analyst; Senior Economic Analyst; Supervisor Economic Forecasting (Budgets and Forecasts)

- 1986 – 1987, University of Waterloo
  1986 - 1987: Course instructor and research assistant.

RECENT REGULATORY APPEARANCES:

Witness at the following OEB proceedings:

- EB-2007-096 THESL CDM Recovery Application, June 2007
- EB-2007-0063 Smart Meter Combined Proceeding, June 2007

CURRICULUM VITAE OF
Ben La Pianta

EDUCATION:

- ***Queen's University,*** Master's Degree in Business Administration
- ***Ryerson University,*** Bachelor's Degree in Electrical Engineering

BUSINESS EXPERIENCE:

October 2006 – Present	Toronto Hydro Electric System Limited
	Vice-President, Distribution Grid Management
2003-2006	Toronto Hydro Electric System Limited
	Manager, Investment Planning, Asset Management

CURRICULUM VITAE OF
Eduardo E. Bresani

EDUCATION:

- Master of Business Administration, York University
- Master of Science, Computer Science, U.S. Naval Postgraduate School
- Master of Science, Information Systems, U.S. Naval Postgraduate School
- Bachelor of Science, Maritime and Naval Science, Peruvian Naval Academy

BUSINESS EXPERIENCE:

- Chief Information Officer, Toronto Hydro Electric Systems Limited
- Vice President of Information Technology, Aviva Canada Inc.
- Regional Director, Information Systems, Chiquita Brands International
- Project / Program Manager, IBM Canada Ltd.
- Manager Systems Development, Peruvian Navy Systems Division
- Navy line operations positions, Peruvian Navy

PROFESSIONAL REGISTRATIONS:

- Project Management Professional (PMP), Project Management Institute

CURRENT PROFESSIONAL ACTIVITIES:

- Chief Information Officer, Toronto Hydro-Electric Systems Ltd.
- Adjunct Professor, School of Information Technology, York University

AWARDS and RECOGNITION:

- IBM Award for Outstanding Technical Achievement
- IBM Marketing Excellence Award
- IBM Special Contribution Award

OTHER DEVELOPMENT PROGRAMS:

- Aviva Executive Development Program, Joint program by the London School of Business and Wharton School of the University of Pennsylvania
- IBM Account Marketing School
- IBM Systems Training School

CURRICULUM VITAE OF
Ivano N. Labricciosa

EDUCATION:

- 2002 Queen's University, Master of Business Administration
- 1997 University of Toronto, Master of Engineering
- 1985 University of Western Ontario, Bachelor of Engineering Science

BUSINESS EXPERIENCE:

- 22 Years Electric Distribution Utility Experience
- Current Position – Vice-President Asset Management

PROFESSIONAL REGISTRATIONS:

- Member – Professional Engineers of Ontario (PEO)
- Member – Institute of Electrical & Electronic Engineers (IEEE)

REGULATORY APPEARANCES:

- EB-2007-0063, Smart Meter Hearings – 2007
- EB-2005-0145, Conservation Demand Management Hearings – 2005

CURRENT PROFESSIONAL ACTIVITIES:

- Member – Queen's Business Club Toronto Chapter

INDUSTRY ASSOCIATIONS & COMMITTEES:

- Member – Canadian Electric Association (CEA) Distribution Council
- Member – Canadian Standards Association (CSA)
- Member – IEEE Power Engineering Society

- Member – CEA Technology Incorporated Distribution Asset Life Cycle Management
- Member – Ontario Utility Smart Meter Association

CURRICULUM VITAE OF
Asheef Jamal, CGA

EDUCATION:

- Certified General Accountant
- Internal Controls Courses/Seminars (Bill 198/OSC requirements compliance)
- Certified Network Administrator (Novell) Course

PROFESSIONAL REGISTRATIONS:

- Certified General Accountants Association of Ontario and Canada

BUSINESS EXPERIENCE:

- **Controller -Toronto Hydro-Electric System Limited**
  October 2006 to Present
- **Director, Risks and Controls –Toronto Hydro Corporation**
  May 2005 to September 2006
- **Controller – Toronto Hydro Corporation**
  May 2004 to April 2005
- **Director, Finance – Toronto Hydro Energy Services Inc.**
  April 2002 to April 2004
- **National Financial Systems Controller/Senior Financial Analyst – Group Telecom**
  September 1999 to March 2002
- **Public Accounting and Auditing Firms**
  May 1992 to August 1999

CURRICULUM VITAE OF
Anthony M. Haines

EDUCATION:

- University of Lethbridge (1983)
- Bachelor of Commerce
- Prerequisite program for admission into the Institute of Chartered Accounting

BUSINESS EXPERIENCE:

- **Toronto Hydro-Electric System Limited**
  September 2006 – Present, President
- **Toronto Hydro Corporation**
  May 2005 – September 2006, Chief Administrative Officer
- **Hydro Ottawa Limited**
  2003 – 2005, Chief Operating Officer
- **Enlogix Inc. (Westcoast Energy Inc.)**
  1998 – 2003, President & CEO
- **Union Gas (Westcoast Energy Inc.)**
  1996 – 1998, Vice-President of Strategic Planning
- **Centra Gas British Columbia Inc. (Westcoast Energy Inc.)**
  1994-1995, Vice-President of Strategic Planning, Regulatory Affairs, Gas Supply, and IT
  1992 – 1993, Director of Strategic Planning and Regulatory Affairs
  1989 – 1991, Manager of Strategic Planning
- **ICG Resources Ltd.**
  1985 – 1988, Chief Accountant
- **Coopers & Lybrand**
  1983 – 1984, Articling Student

REGULATORY APPEARANCES:

Witness before the BCUC:

- 1990 – 1996 Various procedures

Witness before OEB:

- Toronto Hydro-Electric System Limited's 2006 Electricity Distribution Rate Application (EB-2005-0421)

DESCRIPTION OF TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

OVERVIEW

Toronto Hydro-Electric System Limited ("THESL") is the electricity distributor licensed by the Ontario Energy Board to serve the City of Toronto. A 100 percent-owned subsidiary of Toronto Hydro Corporation ("THC"), THESL is the successor to the six former hydro-electric commissions of the municipalities which amalgamated on January 1, 1998 to form the City of Toronto. THC, THESL and other affiliates of THESL were incorporated under the *Business Corporations Act* (Ontario) on June 23, 1999. The sole shareholder of THC is the City of Toronto. THC, in turn, owns 100 percent of the shares of THESL.

THESL delivers electricity through a complex network of overhead wires supported by over 159,000 poles and over 7,600 kilometres of underground wires through transformer stations, underground vaults, cable chambers, and associated switching facilities and structures, to approximately 678,000 customers in residential, general service, and large use classes. In 2006, THESL distributed 25.5 terawatt-hours of electricity, representing approximately 18 percent of the electricity consumed in the province of Ontario, and served a peak demand of 5,018 megawatts. THESL's annual revenue inclusive of electricity commodity revenue in 2006 was $2.24 billion. THESL employs a full-time workforce of 1,609 skilled employees who are dedicated to delivering a safe and reliable supply of electricity to customers.

In addition to its traditional distribution activities, THESL has taken a lead role in providing both "smart meters" and conservation and demand management ("CDM") programs to its customers. These activities directly support the Province's goals of reducing growth in energy demand and creating a culture of conservation.

NEIGHBOURING UTILITIES

The following are THESL's neighbouring electric distribution utilities:

- To the west, Enersource Hydro Mississauga;
- To the north, PowerStream Inc.; and
- To the east, Veridian Connections Inc.

HOST OR EMBEDDED UTILITIES

THESL is not a host utility and there are no embedded utilities in THESL's distribution service area.

Ontario

Electricity Distribution Licence

ED-2002-0497

Toronto Hydro-Electric System Limited

Valid Until
October 16, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 17, 2003

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means: Toronto Hydro-Electric System Limited;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

14 "**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

15 "**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

16 "**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

17 "**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer.

18

2 Interpretation

19

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day.

20

3 Authorization

21

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

22

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

23

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

24

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

41

a) the building lies along any of the lines of the distributor's distribution system; and

42

b) the owner, occupant or other person in charge of the building requests the connection in writing.

43

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

44

a) the building is within the Licensee's service area as described in Schedule 1; and

45

b) the owner, occupant or other person in charge of the building requests the connection in writing.

46

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

47

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

48

8 Obligation to Sell Electricity

49

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

50

9 Obligation to Maintain System Integrity

51

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

52

10 Market Power Mitigation Rebates

53

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

54

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board. 55

12 Separation of Business Activities

56

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board. 57

13 Expansion of Distribution System

58

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 59

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine. 60

14 Provision of Information to the Board

61

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time. 62

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs. 63

15 Restrictions on Provision of Information

64

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. 65

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed: 66

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 67

b) for billing, settlement or market operations purposes; 68

c) for law enforcement purposes; or 69

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 70

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. 71

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent. 72

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed. 73

16 Customer Complaint and Dispute Resolution 74

16.1 The Licensee shall: 75

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 76

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 77

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours; 78

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 79

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective. 80

17 Term of Licence

17.1 This Licence shall take effect on October 17, 2003 and expire on October 16, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

96

97

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence.

98

1 The City of Toronto as of January 1, 1998.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

100

101 This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

102 The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

103

104

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

105

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it.

106

APPENDIX A MARKET POWER MITIGATION REBATES

107

1 Definitions and Interpretation

108

In this Licence,

109

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

110

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

111

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

112

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO.

113

2 Information Given to IMO

114

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

115

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

116

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*.

117

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

118

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

119

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.*

120

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

121

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

122

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

123

3 Pass Through of Rebate

124

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

125

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

126

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

127

c embedded distributors to whom the distributor distributes electricity.

128

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

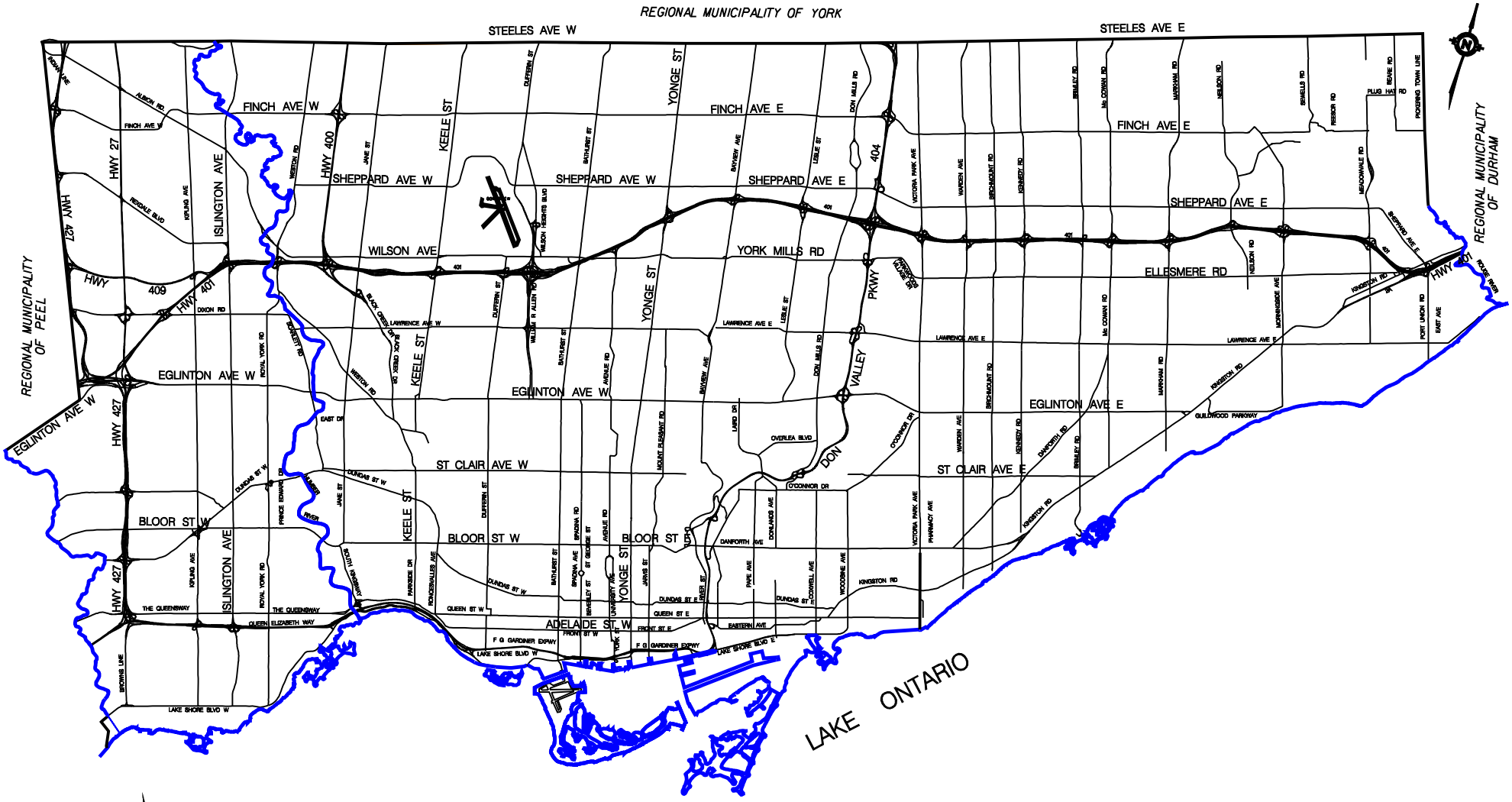
129 If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

130 "ONTARIO POWER GENERATION INC. rebate"

131 Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

132 Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

133 Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.



toronto hydro
electric system

Service Area Map

CORPORATE STRUCTURE AND GOVERNANCE FRAMEWORK

TORONTO HYDRO CORPORATION ("THC")

THC is a holding company that wholly owns the following subsidiaries:

- Toronto Hydro-Electric System Limited
- Toronto Hydro Energy Services Inc.
- Toronto Hydro Telecom Inc.
- 1455948 Ontario Inc.

THC is wholly-owned by the City of Toronto.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED ("THESL")

THESL was incorporated under the *Business Corporations Act* (Ontario) on June 23, 1999. Its principal business is the distribution of electricity in the City of Toronto.

THESL has no subsidiaries.

TORONTO HYDRO ENERGY SERVICES INC. ("TH Energy")

TH Energy was incorporated under the *Business Corporations Act* (Ontario) on June 23, 1999. TH Energy currently holds electricity retailer, wholesaler and generator licences and a gas marketer licence, provides energy efficiency products and services and delivers street lighting and expressway lighting services.

TORONTO HYDRO TELECOM INC. ("THTI")

THTI was incorporated under the *Business Corporations Act* (Ontario) on September 26, 2000. It provides fibre optic cable capacity and manages data communications services.

1455948 ONTARIO INC.

1455948 Ontario Inc. was incorporated under the *Business Corporations Act* (Ontario) on December 21, 2000. It is a partner with OPG EBT Holdco Inc. in the EBT Express Partnership. EBT Express Partnership owns a majority of the shares in The SPi Group Inc. which operates the main electricity data communication HUB system in the Province of Ontario.

BOARD OF DIRECTORS

There are 11 members on the THC board of directors all of whom are appointed by the City of Toronto. Of those 11 directors, three are also councillors for the City of Toronto.

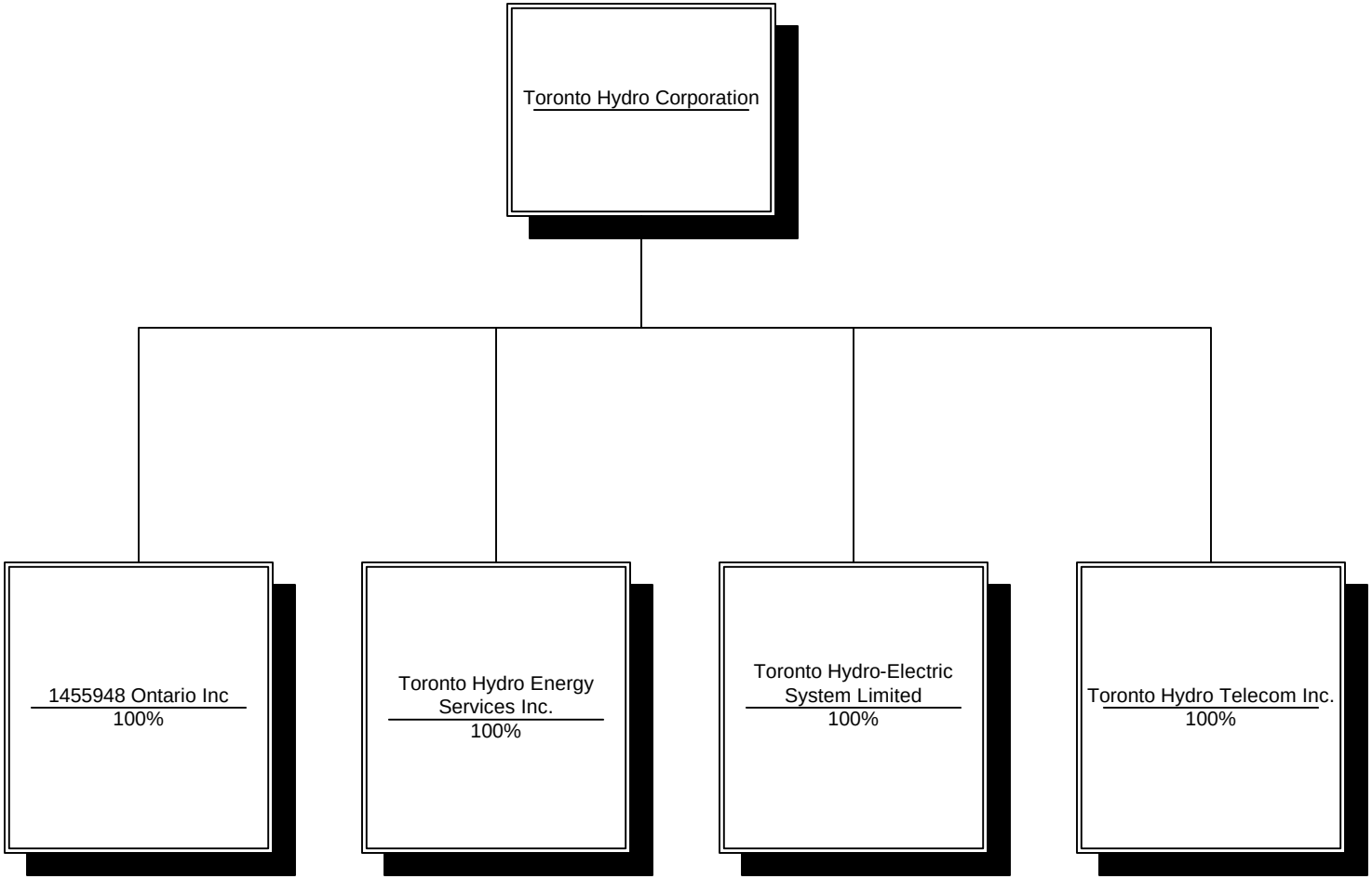
The Board of Directors of THESL consists of six members, all of whom are appointed by THC. Of those six members, four are also members of the Board of Directors of THC and two are individuals who are not members of the Board of Directors of any affiliate of THESL.

As shown on the organizational chart in Exhibit B1, Tab 4, Schedule 2-2 of this application, the President of THESL reports to the President and CEO of THC. Also as shown on the organizational chart in Exhibit B1, Tab 4, Schedule 2-3 of this application, three individuals – Ave Lethbridge, Vice-President, Organizational Effectiveness; Richard Lu, Vice-President, Environment, Health & Safety and Chief Conservation Officer; and JS Couillard, Chief Financial Officer – who report directly to the President and CEO of THC, also report indirectly to the President of THESL. The Vice-President of Treasury, Regulatory and Rates reports directly to the Chief Financial Officer of THC and reports indirectly to the President of THESL. The Vice-President, General Counsel and Corporate Secretary of THESL reports directly to the President and CEO of THC and reports indirectly to the President of THESL.

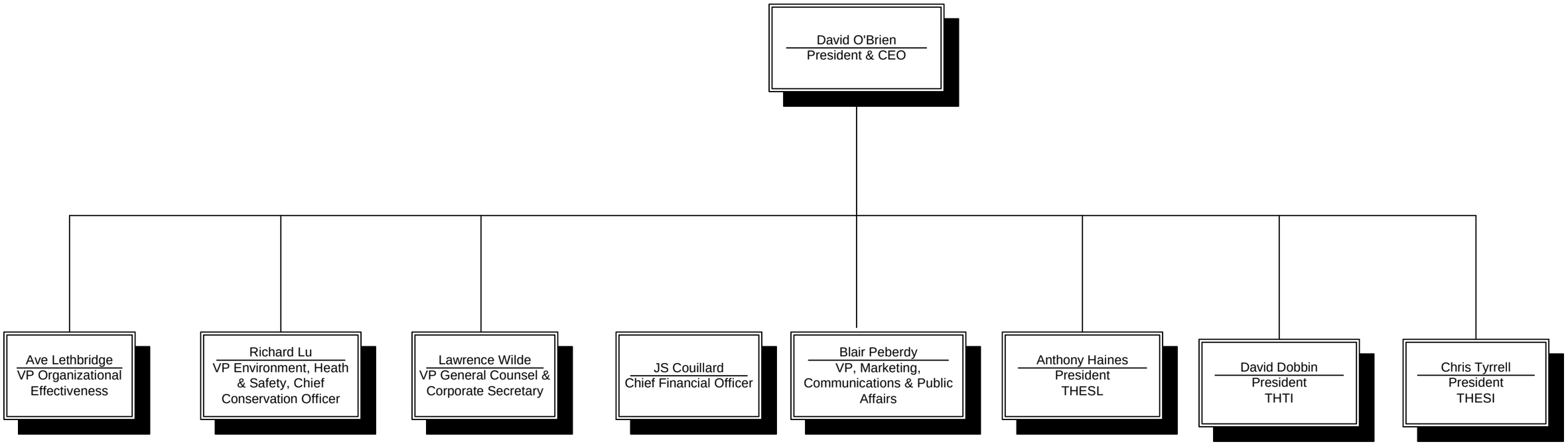
SERVICES PROVIDED TO/BY THESL.

A description of services provided to and by THESL within the corporate structure and governance framework herein described is provided in the Shared Services Inventory at Exhibit Q1, Tab 2, Schedule 1 of this application.

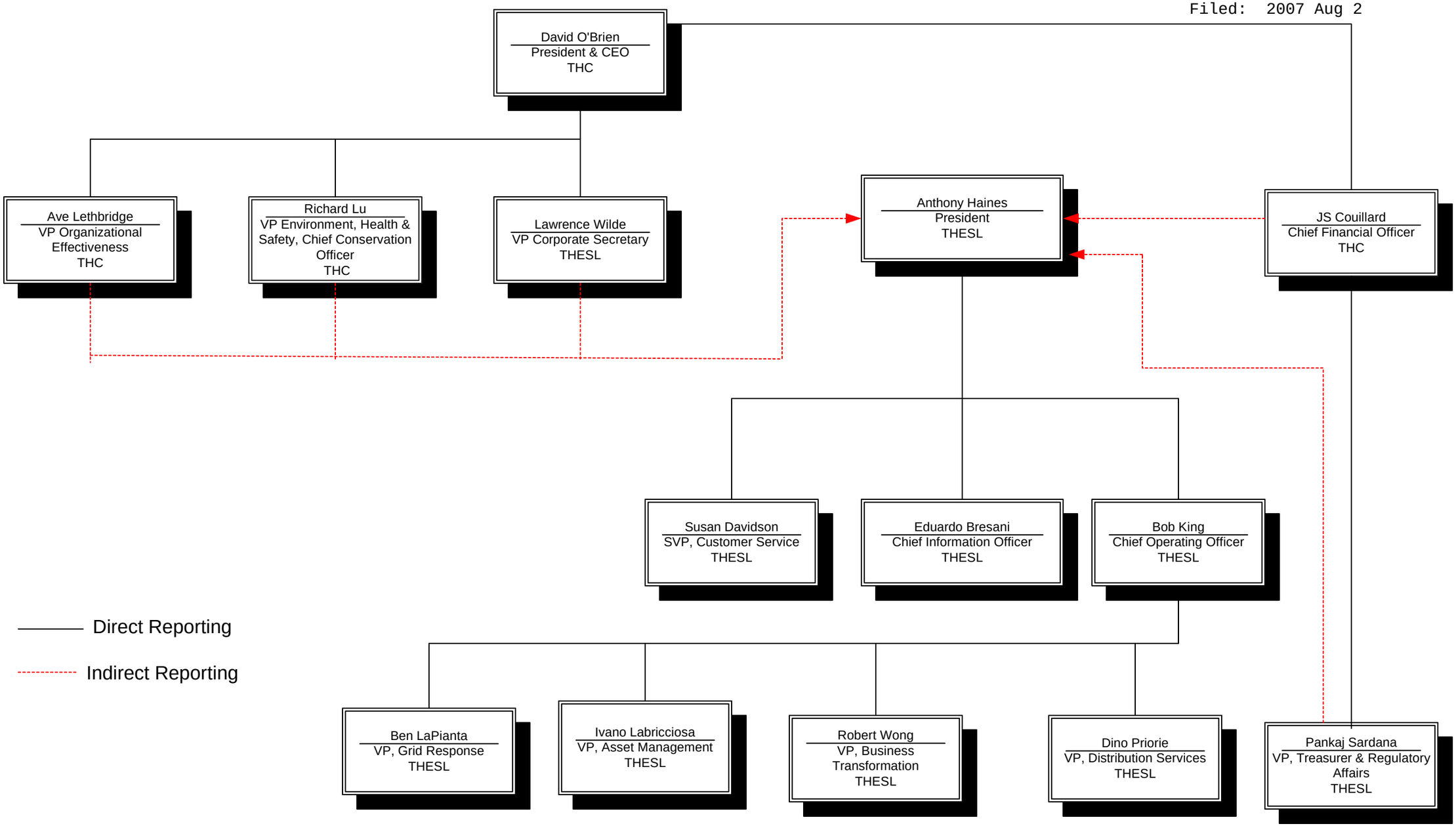
Corporate Organization Chart



Toronto Hydro Corporation Organization Chart



Toronto Hydro-Electric System Limited
Organization Chart



ANNUAL REPORT

The THC Annual Report for the historical year ended December 31, 2006 is included as Appendix A of this Exhibit.

June 6, 2007

To: Ontario Securities Commission
British Columbia Securities Commission
Alberta Securities Commission
Saskatchewan Financial Services Commission (Securities Division)
The Manitoba Securities Commission
Autorité des marchés financiers
New Brunswick Securities Commission
Prince Edward Island Securities Office
Nova Scotia Securities Commission
Securities Commission of Newfoundland and Labrador

Re: Toronto Hydro Corporation (the "Corporation")
2006 Annual Report ("Annual Report")
SEDAR Project No. 1115007

The attached version of the Annual Report replaces the one filed on June 4, 2007.

The Corporation undertook to produce and distribute a web-based, interactive version of the Annual Report, in the interest of environmental responsibility.

Because each page of the interactive report had to be converted into pdf for filing on SEDAR, the Corporation requested that the Annual Report be converted by the vendor that produced the e-version of the Annual Report.

Unfortunately, the electronic link to the pdf version of the Annual Report that was sent to the Corporation inadvertently linked to a draft version of the Annual Report, which resulted in a draft version of the Annual Report being filed on SEDAR.

The Corporation regrets the filing error.

TORONTO HYDRO CORPORATION

Per *Pankaj Sardana*

Commitment

Worth Noting!
- Bright Ideas
- Summer Challenge
- Load Management
- Energy Management
- WiFi

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Commitment

In 2006, Toronto Hydro Corporation continued to achieve strong results across all business units. Our **commitment** to customer service, operational excellence, workplace health and safety, environmental responsibility, energy conservation, sound financial management, community involvement and employee relations has earned us a place among Canada's Top 100 Employers for the second straight year, Top 50 Employers in the Greater Toronto Area, and Top 10 Family Friendly Companies in Canada for 2007.

→ Customer Service

→ Operational Excellence

→ Sustainability

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Committed to Customer Service

Toronto Hydro Corporation is committed to delivering excellent customer service that is founded on the reliability and trust that we have established with you since our beginnings in 1911. We are investing in our infrastructure and providing new and innovative products and services through Toronto Hydro-Electric System Limited, Toronto Hydro Energy Services Inc. and Toronto Hydro Telecom Inc.

Customer Service Representative Cecilia Abas

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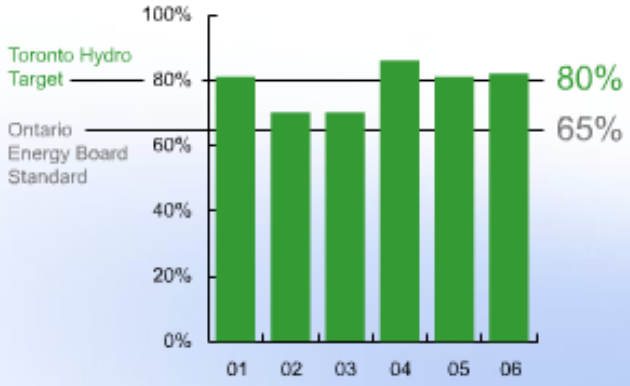
Customer Care

Customer care and Call Centre staff provide fast call response times and complaints resolution. Our goal is to respond to 80 per cent of calls within 30 seconds, exceeding Ontario Energy Board requirements. The quality of the customer transaction is critical as well. Response to complaints is between two and five days, 100 per cent of the time.

Key Account Representatives manage the relationships with our largest customers whose power demand exceeds 1,000 kilowatts per month. These customers represent approximately 30 per cent of our annual revenues and they depend upon high levels of supply reliability and service. Communicating proactively with them ensures they have direct and personal contact with our company to solve problems they may experience with their electricity supply.

Per Cent of Calls Answered Within 30 Seconds



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Connection Activity

In 2006 extensive customer connection activity occurred as residential and commercial building renovations and rebuilds required new or upgraded electrical services. There were fewer connections compared to 2005 due to fewer residential subdivisions coming online.

New Service Connections	2005	2006
Residential and small commercial customers Under 750 volts	4,689	3,503
Large commercial and industrial customers Over 750 volts	219	181

Total Customers: 678,107

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We continue to meet our customers' demands with our Investment Operations Planning process that involves ongoing coordination between planners and operating departments. Work schedules are adjusted to match workforce availability and crews are deployed strategically to avoid backlogs. This helps to provide timely response to customer orders for new service installations.

The Canadian Opera Company's new home, the Four Seasons Centre for the Performing Arts, came online in June 2006. As Canada's first purpose-built opera house, the new facility showcases advancements in modern engineering and acoustical design, featuring the world's longest free-span glass staircase in the main lobby and a European-style, horseshoe-shaped auditorium ensuring the best possible sightlines.

Photo credit:
Steven Evans Photography

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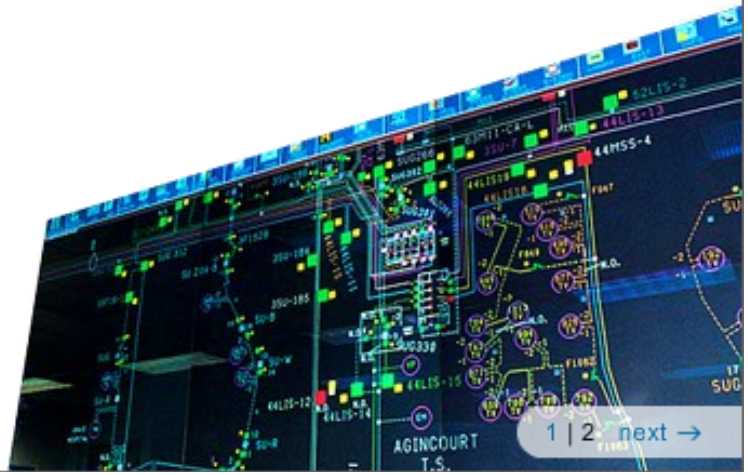
Power Outage Management

In 2006 we completed the installation of a power outage management system to help streamline emergency response activities and communications to customers during power interruptions. Fully operational in 2007, it will link our control centre and emergency electrical tradespeople more closely to customers experiencing service interruptions.

Eventually, we will utilize 'outbound calling technology' to notify customers that crews have been dispatched when a power outage occurs in a neighbourhood.



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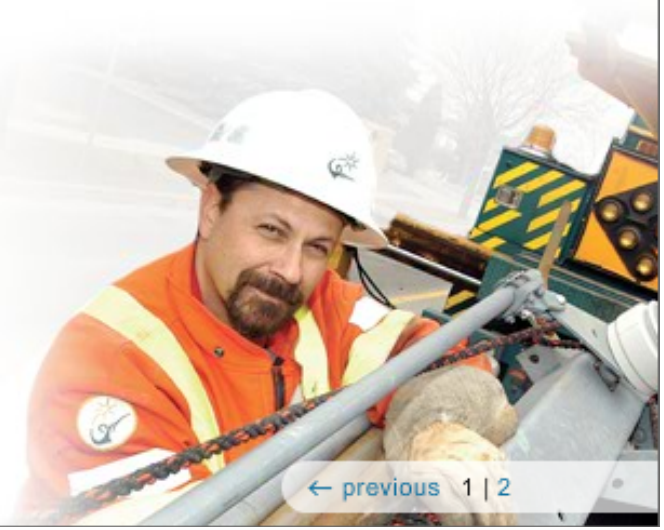
Power Outage Management (continued)

Our Service Delivery Improvement Team has enhanced the communications between the office and the field to shorten response times during major outages. Materials inventories have been standardized on the trucks for improved coordination across departments.



Gilles Gallant, Certified Crew Leader, Lines

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Committed to Operational Excellence

Success depends upon our ability to execute. We are committed to providing our workforce with the resources, tools and training required to meet our business goals. Our focus on streamlined process improvements has enabled us to move forward across all business units. The results: targets met, field operations aligned and efficiencies gained.

Vault Inspectors George Avila (left) and Ron Noro

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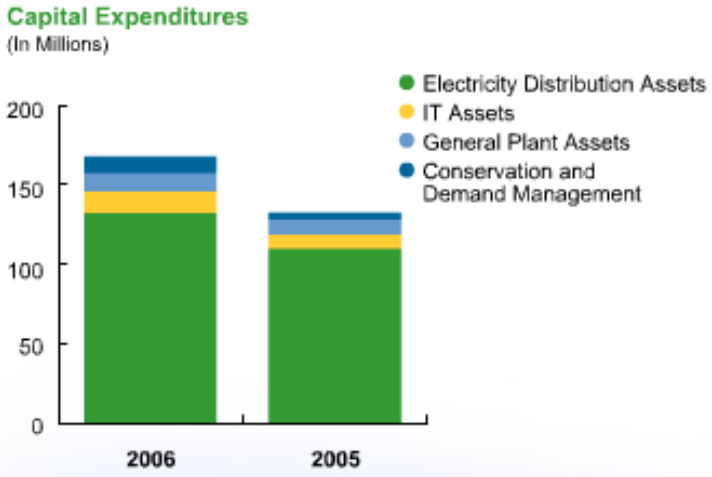
Infrastructure Investment

Investments in the renewal of our downtown distribution system and in certain residential neighbourhoods are proceeding at a measured pace to maintain or improve reliability.



Completing 100 per cent of the annual capital investment plan on time and within budget requires the tight coordination of design, materials procurement and crew scheduling. Frequent reviews of work plans ensure that adjustments are made quickly if required, and that communications between planners, inventory control and operations are clear. This integrated planning and execution process enables us to complete more capital work while lowering costs.

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Smart Metering Technology

In 2006 our smart meter installations totalled 193,000. Toronto Hydro-Electric System staff worked closely with the government and other utilities to develop meter specifications that enabled many local distribution companies to commence mass procurement and installation programs. Combined with time-of-use rates that accurately reflect the cost of generating and delivering electricity, the meters will be a tool to encourage customers to shift consumption to off-peak periods.

Total Smart Meter Installations: 193,000

Rick Hiscock, Meter Services, installing a smart meter

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Workplace Health and Safety

Since 1998 we have reduced workplace accidents by 90 per cent, working cooperatively with CUPE Local One. Our commitment to the safety and well-being of our employees is a fundamental part of our culture. As we replace aging equipment, we continue to recruit apprentices into the electrical trades, and we've also hired additional staff in the distribution system design and engineering fields.

Ron Thompson, Welder

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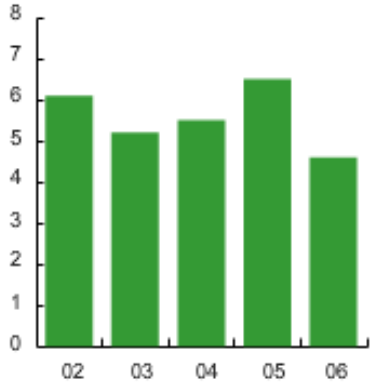
The Early and Safe Return to Work Program was initiated in 2002 to ensure that employees who suffer occupational or non-occupational injuries or illnesses are provided with modified duties to assist with their recovery. The successful management of these cases, in collaboration with CUPE Local One, has resulted in significant reductions in our lost time injury severity and all injury frequency record.

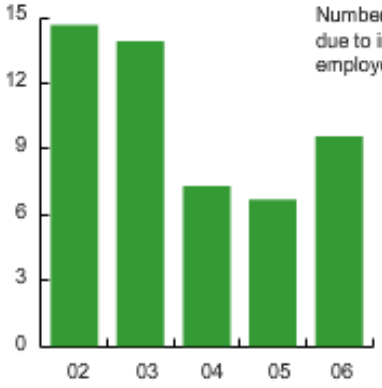
Injury Frequency

Total number of medical care injuries per 100 workers.



Injury Severity

Number of days lost due to injury per 100 employees.



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'Communications in the Workplace' sessions, developed jointly with CUPE Local One, were held throughout 2006 for all employees. Communications sessions, which brought all staff together for discussions about corporate initiatives, were held several times during the year and a company-wide survey was completed by 70 per cent of employees with very positive results.

→ **Environment, Health and Safety Training – 2006**

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Environment, Health and Safety Training – 2006

Close

Topic	Number of Employees Trained
Joint Environment Health and Safety Committee Training	9
First Aid/CPR	304
Accident Investigation	1
Propane Handling and Storage	15
Transportation of Dangerous Goods	35
Asbestos Procedure Training	176
Asbestos Awareness	296
Work Place Hazardous Material Information System	20
Confined Space	18
Confined Space Rescue	166
Poletop Bucket Rescue	119
Fall Arrest Application	139
Ergonomics	245
Early and Safe Return to Work	40
Fire Safety	33
Hearing Conservation	320
Sharps Program	20
Ladder Safety	296
Effective Tailboards	358

Topic	Number of Employees Trained
PCB Cable and Disposal	89
Spill Response	25
Personal Protective Equipment Use and Inspection	48
Fall Prevention Training	245
Work Protection Code and Communication Protocol	662
Basic Electrical Theory	4
Hydro Awareness for Forestry	13
Key Access Training	16
Integrated Customer Response Cross-Border Training	8
Certified Power Lineperson Training (Level 3)	10
Certified Power Lineperson Training (Level 4)	6
Jointer (Level 4)	8
Certified Power Lineperson Training (Level 1)	15
Hydro Awareness for the Utility Worker	49
Total	**3,808**

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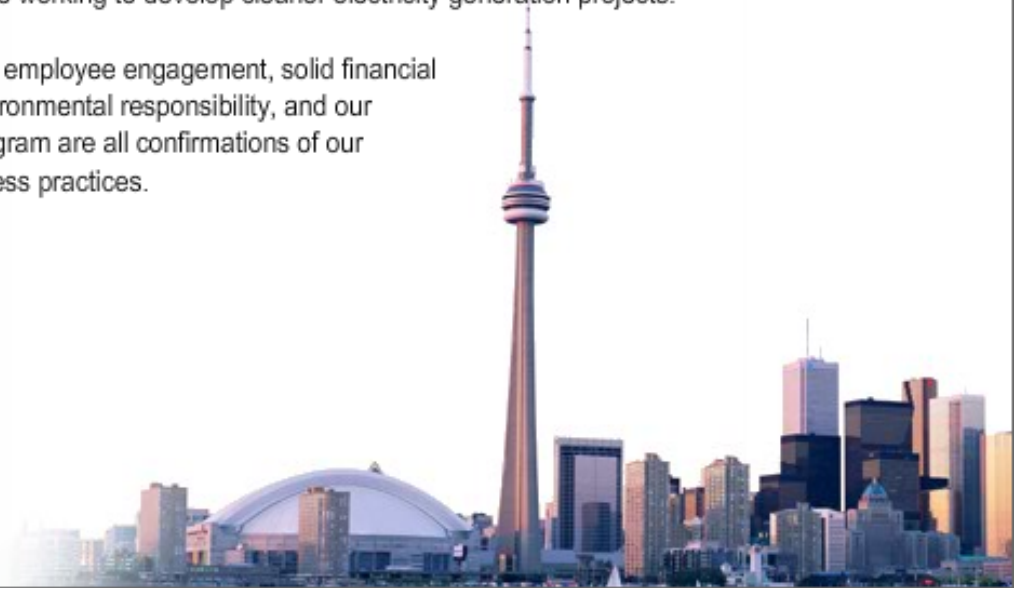
Committed to Sustainability

We are committed to being one of Canada's Top 100 Employers and improving the communities we serve. Toronto Hydro Corporation is one of the leading electricity conservation organizations in Ontario and we are working to develop cleaner electricity generation projects.

Workplace safety, employee engagement, solid financial performance, environmental responsibility, and our Brighter Days program are all confirmations of our sustainable business practices.



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Environmental Responsibility

Toronto Hydro Corporation is continuing to make significant and visible progress since our first Environment, Health & Safety Community Report, *Towards Excellence*, was issued in 2002. We are proud of the continuing wellness and community involvement advancements. This table illustrates our progress in 2006.

→ **Delivering Excellence at a Glance Table**

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Goal: Minimize our impact on the Environment

Indicator	Status	Remarks
Environment, Health & Safety (EHS) Management System	Complete	A full cycle of the EHS System was completed in 2006.
Environmental Assessment	Ongoing	Program continued in 2006.
Recycling Program	Ongoing	Achieved a total waste diversion rate of 85.2%.
PCBs	Ongoing	High-level PCB removal completed in 2006. Continuing with removal of low-level PCBs.
Asbestos	Ongoing	Initiated program to remove asbestos from the distribution system.

Goal: Demonstrate corporate responsibility

Goal: Ensure the development, health and wellness of the workforce

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Goal: Minimize our impact on the Environment

Goal: Demonstrate corporate responsibility

Indicator	Status	Remarks
Environmental Initiatives	Ongoing	Recognition Awards
Community Involvement	Ongoing	Focussed on Six Pillars: Economic Strength, Education, Safety, Environment, Social Services and Volunteerism.

Goal: Ensure the development, health and wellness of the workforce

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Goal: Minimize our impact on the Environment

Goal: Demonstrate corporate responsibility

Goal: Ensure the development, health and wellness of the workforce

Indicator	Status	Remarks
Early and Safe Return to Work (ESRTW) Program	Ongoing	ESRTW Program is a contributing factor in the reduction of lost time severity.

Employee Health & Wellness Sessions:

Transition Perimenopause to Menopause
Antibiotic Awareness
Blood Pressure Clinics
Overview of Diabetes
NAOSH Week
Asthma & Allergy
Prostate Cancer
Healthy Workplace Week

Mike Runighan, Key Account Executive, learns about back care at Employee Wellness Sessions

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Community Involvement
Worth Noting!

Recycling and Conservation

In our own operations we have reduced electricity consumption by two per cent or 343,549 kWh. We achieved an 85.2 per cent waste diversion rate, significantly diverting materials from landfills through reuse and recycling programs. Many of our vehicles run on more environmentally friendly fuels, including bio-diesel and ethanol.

Recycling and Conservation at Work

	2006
Office Waste Diversion Rate	77.5%
Operations Waste Diversion Rate	86.1%
Total Waste Diversion Rate	85.2%
Energy Consumption Reduction (kWh)	343,549 kWh

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Investment Recovery Volumes 2006

Material	2005	2006
Copper	846,693 Lbs	792,970 Lbs
Aluminum	245,390 Lbs	333,929 Lbs
Lead	331,449 Lbs	248,185 Lbs
Sundry Nonferrous	567,397 Lbs	1,207,094 Lbs
Steel	214 tons	242 tons
Scrap Transformers	824	1,207

Reclaiming materials as they are taken out of service from our distribution system is an important part of our environmental responsibility program. The above volumes represent materials reclaimed for each additional calendar year.

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Worth Noting!

Conservation and Demand Management

Conservation and Demand Management are strategic priorities. Our Summer Challenge was the first of its kind in Canada and almost 26 per cent of eligible customers reduced their summer electricity consumption by 10 per cent or more. Collectively, they saved 79.4 million kilowatt-hours of electricity.

Conservation Results – 2006 Highlights

Compact Fluorescent Lightbulbs (CFLs) distributed	574,014
Room air conditioners collected and recycled	6,607
Halogen torchiere floor lamps exchanged	4,785
Strings of incandescent festive lights recycled	24,837
Strings of LED festive lights distributed	4,500

Results for 2006: 146.3 million kilowatt-hours saved
41,260 tonnes of CO_2 emissions diverted

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Commitment

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Customer Service
Operational Excellence
Sustainability
Environmental Responsibility
Recycling & Conservation
Conservation & Demand Management
peaksaver
Community Involvement
Worth Noting!

peaksaver ac

peaksaver ac, Toronto Hydro-Electric System Limited's air conditioner cycling initiative, continues to be a success. More than 24,000 customers have registered and already have their switch installed, providing 41 Megawatts of peak load reduction.

peaksaver de

Under our demand-response program, ***peaksaver de***, we were the first utility in Canada to remotely dispatch standby generation from various commercial buildings in the city. In allowing Toronto Hydro-Electric System Limited to periodically activate these generators, during peak load periods, these customers displace expensive grid power while their standby generators operate for several hours. This also ensures that their back-up generators are properly maintained and tested routinely.

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Volunteerism
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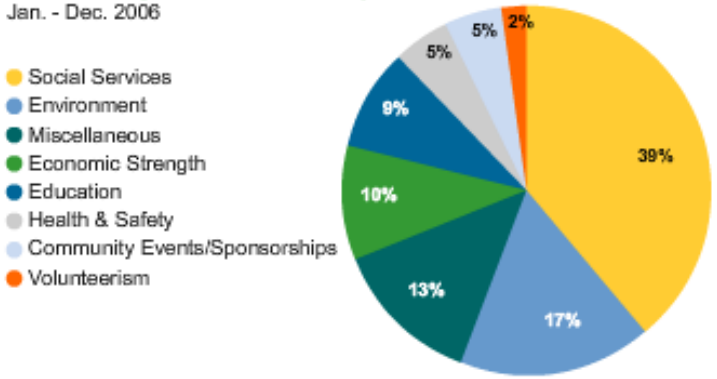
Community Involvement

Our community involvement programs operate under the 'Brighter Days' banner, which is recognized as the bright symbol of Toronto Hydro's commitment to giving back to the community and participating in activities that benefit a wide range of organizations.

In 2006 employees set a new record amount in pledges and raised more than $180,000 for Charity Trust and United Way of Greater Toronto. Our community involvement initiatives also included support in numerous community events to raise money and awareness for health and social service agencies.

Community Involvement Expenditures
Jan. - Dec. 2006



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Volunteerism

'Brighter Days' is built around six pillars: economic strength of our community; support for our education system; safety at work and at home; environmental responsibility; support for the social services in our community; and encouraging our employees to volunteer in their home communities.

Employee volunteerism is an important focus at Toronto Hydro and we actively encourage staff to get involved at work and in their local communities. Community volunteerism reached 175 as employees participated in volunteer activities at home and at work.

→ 2006 Corporate Responsibility Awards and Sponsorship

Debbie Kupcho, Energy Advisor with Customer Management Services, participates in the annual Heart and Stroke Ride for Heart

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2006 Corporate Responsibility Awards and Sponsorship

Awards

- Canada's Top 100 Employers Award
- Greater Toronto's Top 50 Employers
- Canada's Top 10 Family Friendly Employers
- United Way Spirit Award Recognition
- Electricity Distributors Association Innovation Award for 'Summer 2005 Unplugged' energy conservation program

Sponsorships

- Green Toronto Awards
- Local Enhancement and Appreciation of Forests (LEAF)
- Ontario Forestry Association
- 2006 Smog Summit
- Toronto Board of Trade City Summit Alliance
- United Way 211 program
- Toronto Sci-Tech school science fairs
- Duke of Edinburgh Awards
- National Engineering Week
- First Robotics
- City of Toronto Tree Advocacy Program
- United Way Winter Warmth Fund

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Message from the Chairman of the Board and President and Chief Executive Officer

In 2006, Toronto Hydro Corporation successfully met its financial targets and operational goals and established itself as the leading company in delivering effective Conservation and Demand Management (CDM) programs, in support of the Province's drive to create a 'conservation culture' in Ontario. Toronto Hydro-Electric System Limited, which delivers approximately 18 per cent of Ontario's electricity to homes and businesses in the City of Toronto, has become the recognized leader among provincial energy companies in offering new and innovative CDM options to its customers. Two of our programs, ***peaksaver*** and the Summer Challenge, were selected by the Premier to be rolled out across Ontario in 2007.

Overview comments from Clare R. Copeland, Chairman of the Board, and David S. O'Brien, President and Chief Executive Officer, Toronto Hydro Corporation

Message to Shareholders

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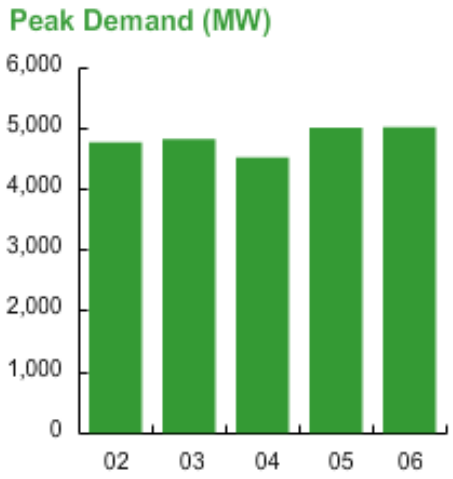
Toronto Hydro Corporation continues to work closely with the Province, the Ontario Power Authority, energy companies, community groups, and commercial partners to bring new initiatives to market, and we support the direction that the government is taking to reduce peak electricity demand in Ontario.

Toronto Hydro Corporation and The Coalition of Large Distributors (Enersource Hydro Mississauga, Hamilton Hydro Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc. and Veridian Connections) are bringing Conservation and Demand Management programs to a combined 1.7 million customers in our service territories.

The Coalition of Large Distributors was recognized by the Ontario Energy Association as 'Company of the Year' for the excellent progress it is making in establishing Conservation and Demand Management in Ontario.



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Toronto Hydro-Electric System Limited also led provincial utilities in the installation of smart meters in 2006. By year-end, we had installed approximately 193,000 meters at homes and commercial buildings across the city. Smart meter installations remain a priority in 2007, and we are also developing 'back end' information management systems that will enable us to interface with the Independent Electricity System Operator, which will be sending time-of-use billing data to Local Distribution Companies (LDCs) in the future.

We were named one of Canada's Top 100 Employers for the second straight year, one of the Top 50 Employers in the Greater Toronto Area, and one of Canada's Top 10 Family Friendly Employers. Our community involvement programs were expanded through our growing support of United Way; the Winter Warmth Fund, which provides hydro bill assistance to low-income Torontonians; Toronto Science Fairs in primary and secondary schools city-wide; our mentorship program targetted to children at risk in downtown elementary schools; the White Ribbon Campaign, which fights violence against women; and we continue to support the many employees who spend time volunteering in their own communities. All Toronto Hydro Corporation business units contributed significantly to our community involvement and volunteer programs.

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In 2006 we began a comprehensive study of corporate sustainability, involving a committee of our employees who are working to help define a social responsibility strategy for the company. We also completed a very successful company-wide employee opinion survey, where 70 per cent of our workforce provided valuable feedback about working at Toronto Hydro.

Changes to the structure of the Board of Directors of Toronto Hydro-Electric System Limited, in accordance with new Ontario Energy Board requirements, and the Board of Directors of Toronto Hydro Energy Services Inc. and Toronto Hydro Telecom Inc. were implemented in 2006. In addition, the Shareholder appointed Councillor Gordon Perks to the Board of Directors of Toronto Hydro Corporation. Mr. Perks joins City Councillors David Shiner and Bill Saundercook, who were reappointed. Toronto Hydro Corporation appointed David Williams and Colum Bastable to the Board of Directors of Toronto Hydro-Electric System Limited.

In April the Ontario Energy Board approved an application by Toronto Hydro-Electric System Limited to decrease the distribution portion of customers' total bills by 2.3 per cent, effective May 1, 2006.

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Net income in 2006 remained stable at $92.4 million, as in 2005, despite lower electricity distribution revenue as a result of weather conditions and the reduction in rates effective May 1, 2006.

Cash from operations after working capital charges decreased to $112.7 million, compared to $325.1 million in 2005. The decrease was primarily due to a difference in timing between the government's rebates paid to customers, lower electricity prices and the winding down of energy contracts that were part of our retail electricity business.

Toronto Hydro Corporation has maintained an A (stable) credit rating from DBRS, and an A- (stable) credit rating from Standard and Poor's. Accordingly, we remain a strong investment-grade company.

In September Anthony Haines was appointed to the position of President, Toronto Hydro-Electric System Limited. Mr. Haines joined Toronto Hydro Corporation in 2005 as Chief Administration Officer. In his new role, he oversees the operations of the regulated company, with a focus on workplace health and safety, increased investment in the distribution system infrastructure and improved customer service.

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In September Toronto Hydro Telecom Inc., under its President David Dobbin, launched the One Zone™ WiFi network in Toronto's financial district and has expanded the service to cover six kilometres in the downtown core, making it the largest WiFi zone in Canada.

Toronto Hydro Energy Services Inc. has maintained its focus on providing value added energy management services to the commercial and industrial sectors and has successfully signed services contracts with a number of large commercial clients. In 2006, Toronto Hydro Street Lighting Inc. merged with Toronto Hydro Energy Services Inc., achieving efficiencies in operations.

The Boards of Directors of Toronto Hydro Corporation and its affiliates have provided sound counsel and outstanding support throughout the year. Our management teams, CUPE Local One, the Society of Professional Engineers and all the employees of the Corporation and its affiliates have had an outstanding year. Their commitment to the community and the services that we provide is evident in the successes that we achieved in 2006.

Clare R. Copeland
Chairman

David S. O'Brien
President and Chief Executive Officer

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Toronto Hydro Corporation operates three major wholly-owned affiliates in the electricity distribution, energy services and street lighting services, and data and communication services. Toronto Hydro-Electric System Limited is our electricity distribution company, holding 95 per cent of the fixed assets and accounting for 97 per cent of the gross revenue of the organization. It serves 599,080 residential customers and 79,027 commercial and industrial customers in the City of Toronto. Toronto Hydro Energy Services Inc. is our energy services company, providing energy management and construction and streetlighting design advice to commercial and industrial customers across the Greater Toronto Area. Toronto Hydro Telecom Inc. provides data and communication services to the commercial sector in Toronto.

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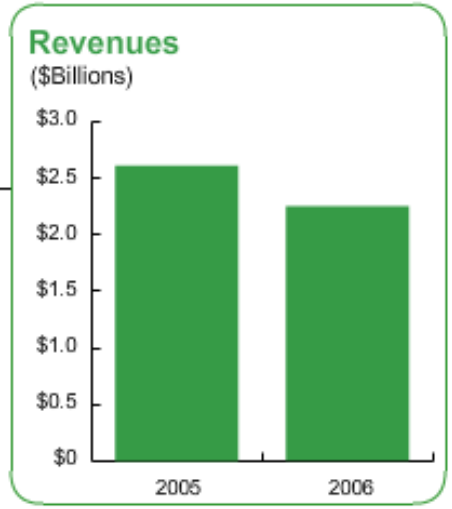

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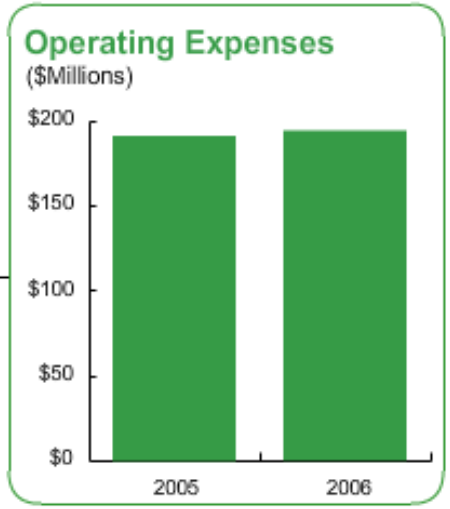

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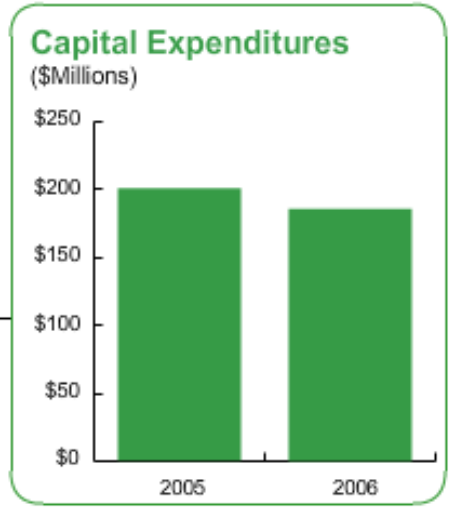

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36.2 minutes

The average length of an interruption for customers who experienced an interruption in the year.

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2.1 interruptions

The average number of times a customer connected to the distribution system is interrupted within a year.

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5,018
megawatts in August 2006
Represents 18 per cent of the Provincial peak

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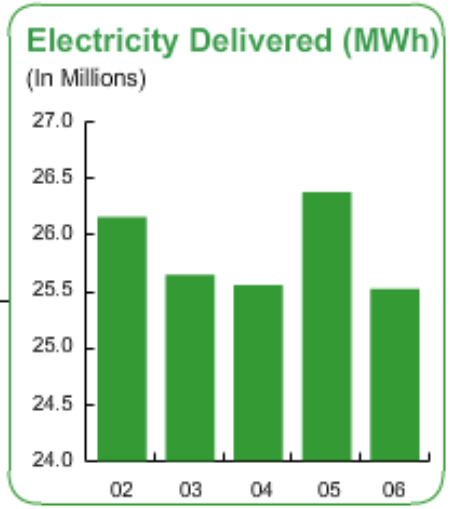

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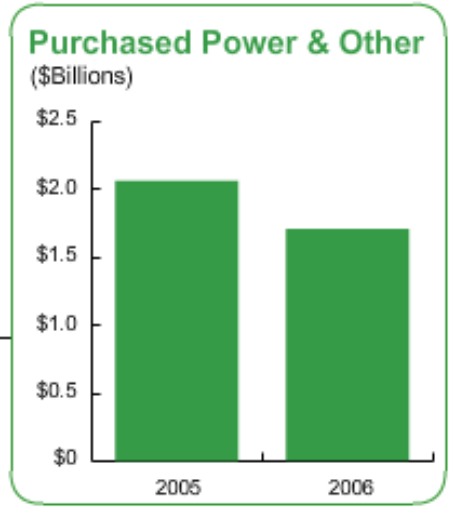

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100%
of all service levels achieved

** Regulated Service Levels: Composite of 10 Customer Service measures. The Ontario Energy Board sets minimum performance standards.*

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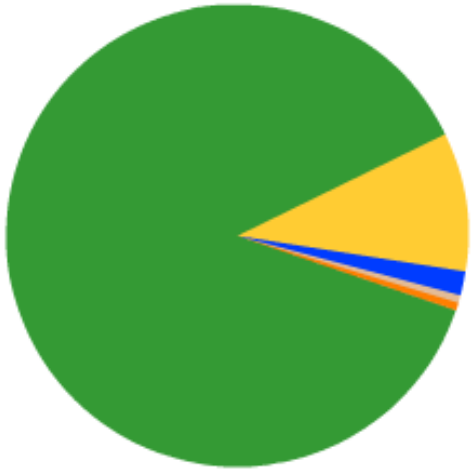
Customers



Residential	599,080
General Service 0–50 kW	67,017
General Service 50–1,000 kW	11,445
General Service 1,000–5,000 kW	516
General Service >5,000 kW (also called Large Users)	49

Total Number of Customers:

678,107

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1,343

Toronto Hydro Energy Services Inc. Employees

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Customer Average Interruption Duration Index – The average length of an interruption for customers who experienced an interruption in the year.

KiloWatt-hour (kWh) – A measure of electrical energy, enough to operate 66 15-watt compact fluorescent light bulbs for an hour.

Megawatt (MW) – A measure of electrical energy equalling 1,000 kilowatts, or enough electricity to power 66,000 15-watt compact fluorescent light bulbs.

MegaWatt-hour (MWH) – 1 MegaWatt-hour is equal to 1,000 kiloWatt-hours.

Peak load – The maximum demand for power, measured in kiloWatts, that occurs within a stated period of time. Toronto Hydro's peak system load (or peak demand) normally occurs in summer because of power demands for air conditioning.

System Average Interruption Duration Index – The average length of an interruption to all customers connected to the distribution system within a year.

System Average Interruption Frequency Index – The average number of times a customer connected to the distribution system is interrupted within a year.

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- **Regulated Business**
  - Toronto Hydro-Electric System Limited
- **Unregulated Business**
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  - Toronto Hydro Telecom Inc.

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Profile

Toronto Hydro Corporation operates three major wholly-owned affiliates that carry on the business of electricity distribution; energy management services and street lighting; and data and communication services. The City of Toronto is Toronto Hydro Corporation's sole shareholder.

Services

- Provides policy and strategic direction for the three affiliates.
- Manages shareholder and key business relationships.
- Promotes workplace and public awareness about electricity safety and energy conservation.

David S. O'Brien
President and
Chief Executive Officer,
Toronto Hydro Corporation

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2006 Achievements

- ☑ Enhanced Corporate Governance structure in accordance with new Ontario Energy Board requirements.
- ☑ Met financial commitments to Shareholder.
- ☑ Named one of Canada's Top 100 Employers; one of the Top 50 Employers in the Greater Toronto Area; and one of Canada's Top 10 Family Friendly Employers.
- ☑ Conducted company-wide employee survey, achieving an employee participation rate in excess of 70 per cent.
- ☑ Maintained a strong investment-grade credit rating.
- ☑ Continued to support employee participation in the community.
- ☑ Diverted 85.2 per cent of waste materials from landfill through our 'Reduce, Reuse, Recycle' program.
- ☑ Supported the City's Urban Forest campaign, Ontario Forestry Association and Local Enhancement and Appreciation of Forests through tree-planting initiatives and forestry education programs.
- ☑ Implemented the use of Forest Stewardship Council (FSC) certified paper for many printing applications.

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2007 Objectives

- Continue our emphasis on workplace health and safety and environmental responsibility.
- Enhance customer service across all business units.
- Maintain engaged and empowered employees who continue to be proud to work for Toronto Hydro.
- Provide consistent and fair return to our Shareholder.

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Toronto Hydro-Electric System Limited (THESL)

Profile

Toronto Hydro-Electric System Limited is one of the largest municipal electric distribution utilities in Canada, delivering electricity to a broadly diversified, economically robust, residential, commercial and industrial customer base in the City of Toronto.

Anthony Haines
President,
Toronto Hydro-Electric System Limited

Services

- Ensures the safe and reliable delivery of electrical power to over 678,000 residential, commercial and industrial customers.
- Plans, maintains and operates Toronto's electrical distribution system infrastructure safely, efficiently and in an environmentally responsible manner.
- Delivers consistent, high-quality customer service and account management.
- Leads Ontario in the design and delivery of electricity Conservation and Demand Management programs.

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2006 Achievements

- ☑ Reduced electricity distribution rates to all customers.
- ☑ A leader in the delivery of Conservation and Demand Management initiatives to help customers conserve energy, save money and help the environment.
- ☑ Achieved savings of 155MW in our conservation portfolio, exceeding our original 2006 target of 127MW.
- ☑ Partnered with the Ministry of Energy and five major electricity utilities in Ontario (Enersource Hydro Mississauga, Hamilton Hydro Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc. and Veridian Connections) to deliver energy conservation initiatives under the brand powerWISE.
- ☑ Installed 193,000 smart meters, leading all utilities in smart meter initiatives.
- ☑ Achieved a 95 per cent inventory fill rate for all material orders for the third straight year.

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2006 Achievements (continued)

- Recognized with the Coalition of Large Distributors as Ontario Energy Association's Company of the Year.
- Recognized by the International Association of Business Communicators (Toronto) with an Award of Merit for our 'Toronto Unplugged' energy conservation awareness campaign.
- Partnered with United Way and Enbridge Gas Distribution on Winter Warmth Fund to provide financial assistance to low-income customers.
- Continued partnership with the Fatal Light Awareness Program (FLAP) and the City of Toronto on the 'Lights OUT Toronto' program to protect migrating birds.

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2007 Objectives

- Continue to implement Conservation and Demand Management programs.
- Continue the mass installation of smart meters and prepare billing systems for Time-of-Use Rates.
- Enhance reliability by increasing capital investments in our distribution system.
- Continue our focus on customer service.
- Invest in technology to enhance the Time-of-Use rate billing system.
- Continue to be one of the best Canadian utilities in safety, service, reliability, cost and training and launch the 'My Goal is Zero' Workplace Safety Campaign.
- Participate actively in the development of provincial energy strategy in the interests of our customers and Shareholder.

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Toronto Hydro Energy Services Inc.

Profile

Toronto Hydro Energy Services Inc. is a professional energy services company focussed on helping multi-residential, commercial, industrial and institutional customers reduce their energy consumption and realize sustainable energy savings. In addition, it owns and operates the street and expressway lighting assets within the City of Toronto and is involved in the development and operation of renewable, clean-energy generation projects. Toronto Hydro Energy Services Inc. is committed to energy conservation and the development of clean energy initiatives.

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Services

- Assists multi-residential, commercial, institutional, and industrial customers in lowering consumption and costs through energy management solutions.
- Develops, owns and operates renewable, clean energy generation projects in Ontario.
- Maintains street and expressway lighting assets through proactive and preventative work programs.

2006 Achievements

- ☑ Refocussed efforts on Energy Efficiency Projects; managed more than 100 projects and provided web-based energy profiling services to more than 200 subscribers.
- ☑ Successfully concluded the retail electricity commodity portfolio.
- ☑ Completed development for numerous cogeneration, biogas and wind projects.
- ☑ Was a key contributor to the installation of Toronto Hydro Telecom's WiFi deployment.
- ☑ Exceeded service level agreements with the City of Toronto for street lighting operations.

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2007 Objectives

- Become an Energy Services market leader in the Greater Toronto Area.
- Grow the recurring revenue business model, focussing on three strategic services:
  - Energy Management Services (Conservation and Demand Response)
  - Clean/Renewable Generation Development and Asset Management
  - Street Light Services

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Toronto Hydro Telecom Inc.

Profile

Toronto Hydro Telecom Inc. is a network services provider offering a full suite of data communications services to businesses within Toronto – including many of Canada's leading businesses and financial institutions.

Toronto Hydro Telecom possesses a wholly-owned fibre optic network that is completely diverse from those of other carriers. In addition, it owns and operates the largest wireless Internet access zone of its kind in Canada.

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Services

- Provides access to its network of more than 450 route-kilometers of fibre optic cable, connecting over 490 office buildings within Toronto.
- Offers a full suite of managed data communications services from high speed ethernet connectivity to value added services including Voice over Internet Protocol and wireless Internet access.

2006 Achievements

- ☑ Successfully blanketed six square kilometres of Toronto's downtown core with wireless Internet access under the brand name One Zone™ – making it the largest WiFi network of its kind in Canada.
- ☑ Created an intense focus on marketing efforts resulting in increased sales.
- ☑ Introduced higher margin services including data storage and security.

2007 Objectives

- Continue to challenge the marketplace by introducing superior-grade telecom services.
- Continue to offer exceptional customer service – delivering services on time and at a competitive price.
- Convert the One Zone™ WiFi network into a revenue-generating asset.

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Businesses

Toronto Hydro-Electric System Limited

Toronto Hydro Energy Services Inc.

Toronto Hydro Telecom Inc.

Worth Noting!

Businesses

In 2006, Toronto Hydro Corporation continued to achieve strong results across all business units. Our **commitment** to customer service, operational excellence, workplace health and safety, environmental responsibility, energy conservation, sound financial management, community involvement and employee relations has earned us a place among Canada's Top 100 Employers for the second straight year, Top 50 Employers in the Greater Toronto Area, and Top 10 Family Friendly Companies in Canada for 2007.

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Toronto Hydro Energy Services Inc.

During 2006 Toronto Hydro Energy Services Inc. continued to build its market position and reputation as a premier energy services provider. The Company successfully completed its transition out of electricity commodity retailing and focussed on building the capability to deliver energy management services, clean and renewable generation development and street lighting services.

In September the amalgamation of Toronto Hydro Street Lighting Inc. and Toronto Hydro Energy Services Inc. brought new opportunities. While the Street Lighting division continues to focus on managing the 166,000 street lamps in the City of Toronto and provide quick response to lighting problems, it is building on this capability by offering a more robust suite of energy services.

Chris Tyrrell
President,
Toronto Hydro
Energy Services Inc.

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Businesses

Toronto Hydro-Electric System Limited

Toronto Hydro Energy Services Inc.

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Worth Noting!

In 2006 Toronto Hydro Energy Services Inc. managed more than 100 diverse projects with business customers, delivering energy efficiency retrofits, asset renewal, generation development and outdoor lighting services.

Toronto Hydro Energy Services Inc. and its customers' projects continued to attract attention both in trade publications and the mainstream media, reinforcing its strong brand recognition and reputation as an energy services leader.

With an aggressive business plan for 2007 focussing on building value for customers, it will continue to target core institutional, commercial and industrial markets in the Greater Toronto Area.

Toronto Hydro Energy Services Inc. President Chris Tyrrell (left) and Rick Cook, General Manager, Street Lighting Division

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Toronto Hydro Telecom Inc.

In 2006 Toronto Hydro Telecom Inc. capitalized on its solid foundation and commitment to service, and re-emerged in the marketplace as an innovator and visionary. The Company completed its transition to a full service telecom provider offering customers a suite of managed network services from basic connectivity to value added services including security and storage.

The restructuring of the Company's core network to the latest technology and the implementation of Canada's largest wireless Internet access zone (One Zone™) placed Toronto Hydro Telecom Inc. in the media spotlight, raising unprecedented brand awareness.

Capturing the attention of media, municipalities and the public around the world, One Zone™ instantly built brand recognition and credibility for the Company.

David Dobbin
President,
Toronto Hydro Telecom Inc.

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And the conception, construction and completion of One Zone™ with speed, coverage and scalability have positioned Toronto Hydro Telecom Inc. as a market leader in innovation, garnering numerous requests to share expertise with the technology sector and city officials from across North America and Europe.

To date the Company's efforts have been focussed on solidifying Toronto Hydro Telecom Inc.'s brand in the marketplace and strengthening its position as a market leader.

The Company counts many of Canada's leading businesses and institutions among its clients, including financial institutions, mutual fund companies, broadcasters, hospitals, colleges and universities.

Toronto Hydro Telecom Inc. President David Dobbin (left) and Toronto Mayor David Miller at the launch of the WiFi network One Zone™

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With an aggressive sales and marketing plan in place for 2007 and a strong focus on increasing reach, Toronto Hydro Telecom Inc. will target businesses throughout the Greater Toronto Area and pursue a stronger presence in the U.S. wholesale market.

Fibre Service Area

Click map to enlarge

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Businesses

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Governance

The Corporation has developed sound Corporate Governance practices. The Corporation's Board of Directors and Management believe that strong Corporate Governance is essential for creating shareholder value and maintaining investor confidence.

Board of Directors

The Board of Directors of the Corporation is responsible for supervising the business and affairs of the corporation and providing strategic guidance to Management.

The Board of Directors of the Corporation is composed of eight independent Directors and three City Councillors. The Board of Directors has four regularly scheduled meetings each year but meets as often as is necessary to fulfill its responsibilities to the Corporation.

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Commitment

Since its appointment on April 20, 1999, the Board has worked to put in place a system of Corporate Governance that meets the requirements established by the Ontario Securities Commission and, more recently, the applicable rules adopted by Canadian Securities Administrators. As part of its ongoing commitment to Corporate Governance, the Board of Directors operates in accordance with a board mandate, and its committees operate in accordance with the committee charters, reviewed and approved by the Board of Directors.

Committees

The Board of Directors believes that its ability to discharge its responsibilities is enhanced by the active participation of committees in the Corporate Governance process. Currently there are four committees of the Board of Directors:

- Audit
- Corporate Governance
- Compensation
- Environment, Health and Safety

Each committee meets regularly throughout the year and provides an update at meetings of the Board of Directors on material matters considered by the committee.

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Audit Committee

The primary function of the Audit Committee is to assist the Board of Directors in fulfilling its responsibilities with respect to financial reporting, internal financial control structure, financial risk management and external audit functions. In accordance with rules published by Canadian Securities Administrators, the Audit Committee has implemented a Policy on Provision of Services by External Auditors and a Policy on Submission and Treatment of Complaints Regarding Accounting or Audit Matters.

Corporate Governance Committee

The primary function of the Corporate Governance Committee is to assist the Board of Directors in fulfilling its corporate governance oversight responsibilities. The Corporate Governance Committee is responsible for developing, and ensuring compliance with, governance policies and procedures.

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Compensation Committee

The primary function of the Compensation Committee is to advise and assist the Board of Directors with respect to the assessment of the performance and compensation of the Chief Executive Officer, and oversight of the compensation structure and benefit plans and programs of the Corporation and its affiliates.

Environment, Health and Safety Committee

The primary function of the Environment, Health and Safety Committee is to advise and assist the Boards of Directors with respect to environment, health and safety matters arising out of the activities of the Corporation and its subsidiaries.

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Code of Business Conduct

The Board of Directors recognizes that a strong ethical culture is required to protect its customers, suppliers, employees, officers and shareholder. All employees, officers and directors of the Corporation are required to comply with the principles set out in the Code of Business Conduct, which was implemented by the Corporation in 2004. The Code provides for the appointment of an Ethics and Compliance Officer and establishes a direct hotline to the Ethics and Compliance Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. The Ethics and Compliance Officer reports quarterly to the Audit Committee on the nature of complaints received including those related to audit and accounting matters.

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Disclosure

The Board of Directors recognizes the importance of complying with all disclosure requirements imposed by Canadian Securities Administrators and is committed to promoting consistent disclosure practices aimed at accurate and timely disclosure of material information.

To ensure consistent and appropriate disclosure practices, the Corporation has adopted a Disclosure Policy to govern the disclosure by its employees, officers and directors of material information about the Corporation and has established a Disclosure Committee composed of senior executives to assist the Chief Executive Officer and the Chief Financial Officer in making accurate, complete and timely disclosure. The composition and operation of the Disclosure Committee are established in the Disclosure Policy.

The members of the Corporation's Board of Directors can be seen here.

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Clare R. Copeland (1 2 3 4 Chairman) A D

Colum Bastable 2

Janet Beed 1 3 4 D

David L. Bumstead 1 3 4 C

Patricia Callon 1 2 B

Brian Chu 1 2 A (Chair) C

L. Ross Cullingworth 1 2 C (Chair)

Dr. Frank Frantisak 1 3 4 A B (Chair)

Jeffrey G. Marshall 1 3 4 D (Chair)

David Williams 2

Councillor Gordon Perks 1

Councillor Bill Saundercook 1 3 4 B

Councillor David Shiner 1 3 4

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Clare R. Copeland (1 2 3 4 Chairman) A D

- Chairman, Toronto Hydro Corporation
- Chairman, Toronto Hydro-Electric System Limited
- Chairman, Toronto Hydro Energy Services Inc.
- Chairman, Toronto Hydro Telecom Inc.
- Chief Executive Officer, Falls Management Company
- Former President and CEO, Peoples Jewellers Corp.
- Former Chair, Sun Media Corp.
- Former Chair, Ontario Place
- Former Chair and Executive Officer, OSF Inc.

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Colum Bastable 2

- President & CEO, Cushman & Wakefield Lepage Inc.
- Director, Decision Dynamics Technology Inc.
- Vice-Chair, Board of Governors, McMaster University
- Former President & CEO, Royal Lepage Limited

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Janet Beed 1 3 4 D

- President and Chief Executive Officer, Markham Stouffville Hospital
- Former Partner, Deloitte Consulting
- Former Chief Operating Officer, University Health Network: Toronto General Hospital
- Former Vice-President, Ontario Cancer Institute/Princess Margaret Hospital
- Former Director of Nursing, Hospital for Sick Children

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David L. Bumstead 1 3 4 C

- Director, Atlas Copco Canada Inc.
- Former Director, Noranda Inc., Falconbridge Ltd., and associated companies
- Former Director, Battle Mountain Gold Co.
- Former Director, Norcen Resources
- Former Director, Brenda Mines Ltd.
- Former Director, Kerr Addison Mines

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Patricia Callon 1 2 B

- Corporate and Securities Lawyer/Consultant
- Advisor, Ontario Securities Commission
- Director, MicroSkills Community Development Centre
- Former Vice-President and Associate General Counsel, Canadian Imperial Bank of Commerce
- Former Director, CIBC Trust Corporation, CIBC Securities Inc., CIBC Life Insurance Company Limited, CIBC Investor Services Inc. and TAL Global Asset Management Inc.
- Former Senior Counsel, Seaboard Life Insurance Company
- Former Counsel, Sun Life Financial
- Former Associate, Blake Cassels & Graydon LLP

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Brian Chu 1 2 A (Chair) C

- Partner, Bogart Robertson & Chu
- Director, Laidlaw Foundation
- Director, Apparel Industry Development Council
- Former Chair, Ontario College of Art and Design
- Former Vice-Chair, Centennial College of Applied Arts and Technology
- Former Vice-Chair, Chinese Cultural Centre of Greater Toronto

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L. Ross Cullingworth 1 2 C (Chair)

- Consultant and past CEO, Brookfield Homes Ltd.
- Former Chairman, Brookfield Homes Ltd.
- Former Director, Brookfield Homes Ltd.
- Former Director, Brookfield Properties Corp.
- Former Director, Carma Corp.
- Former Director, Goldlist Properties Inc.
- Former Director, Canadian Institute of Public Real Estate Companies
- Former Director, RP Eye Research Foundation

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Dr. Frank Frantisak 1 3 4 A B (Chair)

- Former Senior Vice-President, Environmental Services, Noranda Inc.
- Former Director, World Business Council on Sustainable Development
- Former Director, Acres Inc.
- Former Director, Canadian Pulp and Paper Association
- Former Director, Canadian Council for International Business
- Awarded the Order of Canada, 2002
- Recipient of The Golden Jubilee Medal on the 50th Anniversary of the accession of Her Majesty the Queen to the Throne

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Jeffrey G. Marshall 1 3 4 D (Chair)

- Chairman, Smith Marshall
- Director, Brand Energy and Infrastructure Services Inc.
- Director, Lakefield College School Foundation
- Director, Neenah Foundry Company
- Chairman, Ormet Corporation
- Former President and Chief Executive Officer, Aluma Enterprises Inc.
- Founding Chair, former President and Chief Executive Officer, The Ontario Clean Water Agency
- Former President and Chief Executive Officer, Marshall Drummond McCall
- Former President and Chief Executive Officer, Marshall Steel Limited
- Director, Catalyst Paper Corporation

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David Williams 2

- Chairman, Shoppers Drug Mart Corporation
- Chairman, Centerplate Inc.
- Director, Canadian Apartment Properties REIT
- Director, Aastra Technologies Inc.
- Former President and CEO, Workplace Safety Insurance Board
- Former Executive Vice-President, George Weston Ltd.
- Former Executive Vice-President, Loblaws Companies Ltd.
- Former President, National Grocers Co. Ltd.

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Councillor Gordon Perks 1

- City Councillor, Ward 14 (Parkdale-High Park)
- Toronto and East York Community Council
- Member, Budget Committee
- Member, Toronto Board of Health
- Director, Exhibition Place
- Member, Parks and Environment Committee
- Director, Toronto Atmospheric Fund
- Director, Liberty Village Business Improvement Area
- Director, Parkdale Village Business Improvement Area
- Director, Roncesvalles Village Business Improvement Area

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Councillor Bill Saundercook 1 3 4 B

- City Councillor, Ward 13 (Parkdale-High Park)
- Member, Toronto Transit Commission
- Member, General Governance Committee
- Member, Etobicoke York Community Council
- Director, Runnymede Hospital
- Director, Bloor West Village Business Improvement Area & Junction Business Improvement Area
- Member, Swansea Area Ratepayers Association & Town Hall Community Centre & Residence
- Chair, Junction Forum for Arts and Culture
- Member, Pedestrian Committee
- Director, Malta Village Business Association

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Councillor David Shiner 1 3 4

- City Councillor, Ward 24 (Willowdale)
- Member, Community Development and Recreation Committee
- Member, North York Community Council
- Director, Canadian Film Centre
- Member, Eva's Initiatives
- Member, Arts Committee for Public Places
- Former Chair, City of Toronto, Budget Advisory Committee
- Former Member, Toronto Transit Commission
- Former Member, St. John's Rehabilitation Hospital
- Former Member, Enwave District Energy Limited

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Senior Management

Toronto Hydro Corporation

David S. O'Brien
President and Chief Executive Officer

Jean-Sebastien Couillard
Chief Financial Officer

Ave Lethbridge
Vice-President, Organizational Effectiveness

Dr. Richard Lü
Vice-President,
Environment, Health and Safety
Chief Conservation Officer

Blair H. Peberdy
Vice-President,
Marketing, Communications
and Public Affairs

Lawrence Wilde
Vice-President, General Counsel
and Corporate Secretary

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Commitment

Toronto Hydro-Electric System Limited

Anthony M. Haines
President

Bob King
Chief Operating Officer

Jean-Sebastien Couillard
Chief Financial Officer

Eduardo E. Bresani
Chief Information Officer

Susan Davidson
Senior Vice-President, Customer Services

Ivano Labricciosa
Vice-President, Asset Management

Ben LaPianta
Vice-President, Distribution Grid Management

Ave Lethbridge
Vice-President, Organizational Effectiveness

Dino Priore
Vice-President, Distribution Services

Pankaj Sardana
Vice-President, Treasurer and Regulatory Affairs

Robert Wong
Vice-President, Business Transformation

Lawrence Wilde
Vice-President and General Counsel

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Toronto Hydro Energy Services Inc.

Chris Tyrrell
President

Jean-Sebastien Couillard
Chief Financial Officer

Lawrence Wilde
Vice-President and General Counsel

Toronto Hydro Telecom Inc.

David Dobbin
President

Jean-Sebastien Couillard
Chief Financial Officer

Lawrence Wilde
Vice-President and General Counsel

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Commitment

Worth Noting!
- Bright Ideas
- Summer Challenge
- Load Management
- Energy Management
- WiFi

Management's Discussion and Analysis	(91 kb)
Consolidated Financial Statements	(437 kb)

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BRIGHT IDEAS

toronto hydro electric system

As part of Toronto Hydro's commitment to conservation, it was important that we developed a program that focussed not only on energy-efficient products, but also gave customers the tools and knowledge they needed to make **energy-efficient choices.**

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Campaign Goals

Reach and interact with Torontonians, providing education and incentives that motivate them to take action by purchasing and using energy-efficient products, specifically:

- Switch traditional incandescent lights to compact fluorescent lightbulbs (CFLs)
- Turn in old, inefficient, and unsafe halogen floor lamps for efficient compact fluorescent models
- Turn in old, incandescent festive light strings for efficient light emitting diode (LED) models
- Use the Conservation Bureau's coupons to purchase energy-efficient products

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Approach

Designed to save over 25 million kilowatt hours, equal to the annual electricity use of approximately 2,100 homes, the face-to-face campaign ran for six weekends, from October 7 to November 12, 2006.

This campaign maintained the momentum of Toronto Hydro's ongoing mass market conservation efforts, continued customer outreach and provided customers with the necessary tools to make responsible, energy-efficient choices.

Summary of Events

Toronto Hydro executed a series of in-store events including CFL bulb giveaways, a halogen torchiere exchange and incandescent festive lighting exchange and recycling. Events took place at these participating Toronto-area retailers:

THE HOME DEPOT | WAL★MART | COSTCO | Home hardware

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Summary of Events

- Compact fluorescent lightbulb (CFL) giveaways
- Halogen torchiere exchange
- Festive light string exchange
- Conservation Bureau coupons

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Summary of Events

- Compact fluorescent lightbulb (CFL) giveaways
- Festive light string exchange
- Halogen torchiere exchange
- Conservation Bureau coupons

Click the links above for details ↑

For the first four weekends of the campaign, Bright Ideas representatives distributed free CFLs to the first 500 customers at events, generating interest and driving customers to the stores. This got participants engaged and started to transform their purchasing habits towards energy-efficient products. The giveaways created significant in-store traffic and provided the chance to educate the customer on energy efficiency, promote upcoming program activities and provide instant discounts on specific energy-efficient products.

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Summary of Events

- Compact fluorescent lightbulb (CFL) giveaways
- Festive light string exchange
- Halogen torchiere exchange
- Conservation Bureau coupons

Click the links above for details ↑

Customers were encouraged to turn in their halogen torchiere in return for a substantial discount on energy-efficient models. Bright Ideas representatives collected customers' halogen torchiere lamps for recycling, educated customers about the benefits and uses of new energy-efficient compact fluorescent torchiere lamps, and then gave customers a $30 instant discount coupon to purchase a new lamp.

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Summary of Events

- Compact fluorescent lightbulb (CFL) giveaways
- Festive light string exchange
- Halogen torchiere exchange
- Conservation Bureau coupons

Click the links above for details ↑

Customers were encouraged to turn in their old incandescent festive light strings in exchange for a discount coupon for energy-efficient seasonal LED festive lights. Bright Ideas representatives collected customers' old lights for recycling, educated customers about the benefits and uses of new energy-efficient LED strings, and then gave customers a $5 instant discount coupon to purchase new LEDs.

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Summary of Events

- Compact fluorescent lightbulb (CFL) giveaways
- Halogen torchiere exchange
- Festive light string exchange
- Conservation Bureau coupons

Click the links above for details ↑

Every Kilowatt Counts coupons were distributed at every event and featured instant rebates on CFLs, LEDs, motion sensors, thermostats and dimmer switches.

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Results

The campaign surpassed its target electricity reduction of 25 million kWhs and generated a savings of 36 million kWhs, equal to the annual electricity use of approximately 3,000 homes.

- **70,000** free two-packs of CFLs were given away
- **4,800** halogen torchieres were turned in for recycling
- **16,000** customers turned in old festive lights for recycling

(Electricity savings were calculated using industry standard metrics.)

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TORONTO HYDRO SUMMER CHALLENGE

toronto hydro electric system

Summer Challenge is a conservation program designed to educate customers about the benefits of energy conservation & promote a behavioural shift towards a conservation culture, especially during the summer when peak demand is at its highest.

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Approach

Toronto Hydro developed the Summer Challenge based on a model from California. From July 15 to September 15, customers were encouraged to use at least 10 per cent less electricity compared to their weather-normalized consumption for the same period in 2005. If successful, customers received a 10 per cent credit on their bill.

All residential and small commercial customers (using less than 50 kilowatts per month) who had an active and continuous account with Toronto Hydro on or prior to September 1, 2005 were automatically eligible for Summer Challenge. No additional steps were required for enrollment.

At the end of the Challenge, the Customer Information System allowed customers to log on to Toronto Hydro's Web site and see whether they had achieved their target reduction.

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Summary of Events

An aggressive, entirely integrated communication campaign was carried out during the summertime to maximize message exposure, retention and customer participation. Many different vehicles were used. They included:

- Media launch in headquarters lobby
- Radio advertising on 14 stations
- Radio contest on EZRock in August
- Print advertising in the *Toronto Star*, *Eye Weekly*, *Now Magazine* and numerous community papers
- Internet banner ads on The Weather Network Web site
- One-stop TTC ads (televisions in the subway stations)
- Promotional copy printed on customer bills
- Flyers used as bag stuffers at retail partner locations (Home Depot and Wal-Mart)
- Direct mail flyers delivered to all houses in Toronto
- Provided the media with continuous updates on results and what customers were doing to conserve

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Results

Overall, 28.5 per cent (or 153,637) eligible customers took the Summer Challenge and received the 10 per cent credit.

- **51,357** (or 33.4 per cent) achieved a reduction of 25 per cent or more
- **102,280** (or 66.6 per cent) conserved between 10 and 25 per cent less electricity
- Eligible customers saved **70,942,723 kWh** or the annual electricity consumption of approximately 5,900 homes

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Load Management

peaksaver ac is an electricity load management initiative that helps Toronto Hydro-Electric System manage the amount of power used by energy-guzzling residential and small commercial central air conditioners in Toronto.

peaksaver™

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peaksaver ac was designed to easily and effectively minimize the peak energy consumption of the estimated 160,000 central air conditioners in Toronto, thus reducing the strain on the city's grid. At its launch, it was the first and only AC load control program in Canada.

Campaign Goals

Help address Ontario's electricity shortages and provide environmental benefits by:

- Educating customers on peak demand, in particular the summer peak due to air conditioning
- **Reducing Toronto's electricity use during peak periods by 7MW**
- Reducing air pollution and the need to supplement peak demand by importing expensive electricity

Encourage all eligible customers to sign up for ***peaksaver ac*** by:

- Leveraging the short- and long-term benefits of signing up to have the switch installed
- Offering customers $25 for signing up
- Creating a quarterly contest
- Emphasizing the minimal impact on indoor comfort

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Approach

With Ontario facing an electricity supply shortfall, Toronto Hydro set its own target to reduce peak demand by five per cent (250 megawatts) by the end of 2007.

Using a wireless ***peaksaver*** switch, Toronto Hydro can temporarily shift residential air conditioning use by reducing the on/off cycle during critical demand times. The same applies to small businesses with the switch connected to the Heating Ventilating Air Conditioning (HVAC) system. Cycling for residential customers occurred weekdays, from June to September, between 2 p.m. and 6 p.m. for a period of no more than four hours. If at all, customers felt a temporary 1ºC (or less) temperature change.

The program was launched in 2006 and will continue throughout 2007. It was originally designed to incite 2,600 sign-ups and shave 7 megawatts (MW) of peak demand off the grid in the first year.

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Summary of Events

To reach as many residential and small business customers as possible, Toronto Hydro carried out a number of consistent and sustained communication initiatives throughout the year. They included:

- Launch media release and press conference
- Direct mail to residential customers
- Direct mail to small commercial customers
- Articles in our newsletters, online and print
- Advertising in print and broadcast media
- Speaking engagements with team manager and other members
- Presentations at tradeshows
- Participation in industry-related events
- Unique programs run by or with the help of existing partners

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Cross-promotion communication tactics:

- Information and sign-up booths during the three-week Keep Cool summer event at Home Depot stores across the city
- ***peaksaver*** representatives were present to sign customers up during the six-week Fall Bright Ideas campaign at Home Depot, Wal-Mart, Costco, and Home Hardware stores across the city

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Results

The holistic approach and broad reach of the 2006 ***peaksaver ac*** program made it a huge success in terms of sign-ups and energy conservation.

The campaign far surpassed the original goal of 2,600 sign ups and 7MW of peak load reduction.

	Goal	Actual
Residential and Small Business sign-ups	2,600	24,006
Peak Demand Energy Savings	7MW	41MW

Initial customer satisfaction results were overwhelming and suggested that Torontonians were willing to participate because they were increasingly concerned about new power generation, rising prices and the impact on the environment.

The provincial government opted to roll out ***peaksaver ac*** province-wide in 2007.

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Energy Management

The parking garage at the Commerce Court operates 24 hours a day, 7 days a week. Toronto Hydro Energy Services introduced them to a more energy efficient lighting system, which reduced their overall maintenance and energy costs.

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The Challenge

British Columbia Investment Management Corporation, owner of Commerce Court, a prestigious office complex in Toronto's financial district, wanted to save on energy costs and improve the overall level of lighting in the garage. The ambiance created by an effectively lit space was also important.

A reconfigured system was proposed since the lighting system in the garage dated back to the 1990s and could benefit from newer energy-efficient technology. Also, fluorescent lighting in the loading docks and on entry and exit ramps was dimming when exposed to cold air.

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The Solution

While other contractors simply suggested the owner augment the existing lighting system, Toronto Hydro Energy Services recommended new energy-efficient fixtures, reconfigured to provide better lighting levels with fewer fixtures.

- New T8 technology featuring smaller, fluorescent tubes and electronic ballasts was introduced
- Lighting was configured to illuminate the direction of travel rather than across lanes, avoiding glare without shading
- Non-temperature sensitive 200-watt metal halide lamps were placed on ramps and in the loading docks to eliminate the effect of cold temperatures on lighting levels
- Blue metal halide lights were installed to frame the entranceway to attract the after-hours event clientele
- Attractive light fixtures were placed in the entrance and ticket payment areas

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Results

The project took just nine weeks to implement, mostly during off-hours. The new lighting system cut energy usage by more than half and reduced lighting maintenance costs to next to nothing.

"We had a well-presented proposal and well-executed project with results that have been better than expected so it's not surprising that we are extremely pleased with Toronto Hydro Energy Services."

Property Management,
GWL Realty Advisors Inc.

With annual savings of $63,950, the owner will recover the project cost in less than 3½ years.

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toronto hydro telecom

WiFi

As part of Toronto Hydro Telecom Inc.'s commitment to innovation, the company successfully deployed One Zone™ – Canada's largest wireless Internet access zone – in downtown Toronto last year. The campaign, launched in March 2006, was designed to promote awareness of the service and strengthen the Toronto Hydro Telecom Inc. brand by driving home key messages of quality, sustainability and scalability.

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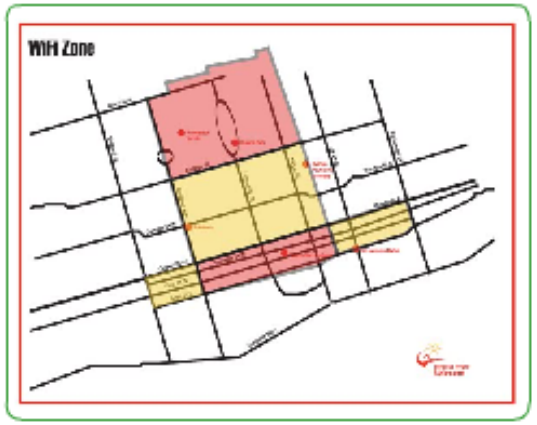
Campaign Goals

Generate 'buzz' around the service and position Toronto Hydro Telecom Inc. as a market leader in emerging telecommunications technologies by:

- Building and maintaining media awareness for the service over a 12-month period
- Creating strong brand recognition for the One Zone™ network
- Garnering positive, accurate and fair coverage in earned media through media events, speaking engagements and press announcements

WiFi Zone



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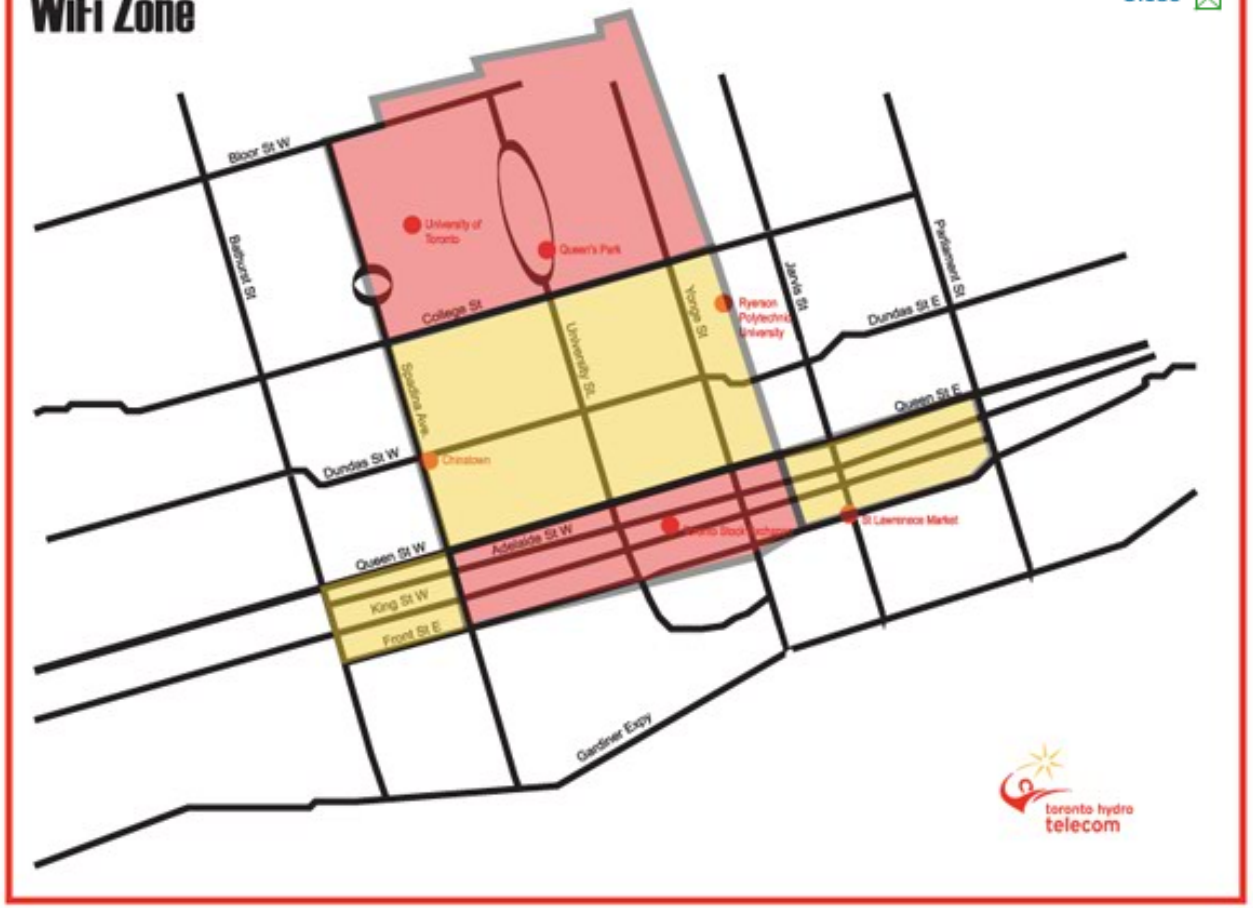
WiFi Zone

Close



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Summary of Events

Toronto Hydro Telecom Inc. executed a series of media events and speaking engagements.

- Official announcement of the creation of One Zone™ – March 7, 2006
- Technical briefing for technology media – July 19, 2006
- Official launch of 'live' service – September 7, 2006
- Major industry speeches and follow-up media

• Press release – Network performance results by independent U.S. research firm – January 2007

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- Major industry speeches and follow-up media

Click the links above for details ↑

Media were invited to join Toronto Hydro Telecom Inc. and "cut the cord" on March 7, 2006. At the event, media kits wrapped in computer cable and decorated with pairs of toy scissors were the first clue that the announcement was a shot across the bow for Toronto Hydro Telecom Inc.'s major competitors in both the cellular and Internet arenas. Mayor David Miller joined Toronto Hydro Corporation and Toronto Hydro Telecom Inc. executives and members of Toronto Hydro Corporation's Board of Directors to mark the countdown to the official launch, slated for September 2006.

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- Major industry speeches and follow-up media

Click the links above for details ↑

Technology media were identified as a key conduit for information out to the general consumer market, and as such were invited to learn more about One Zone™ and its technical capabilities at a special technical briefing in July 2006. The briefing provided a status update on deployment and gave technical media the opportunity for extended Q&A with key Toronto Hydro Telecom Inc. executives. The briefing was also an opportunity to manage the emergence of public affairs issues such as electric magnetic fields (EMFs) and public health; child safety and pornography on public networks; municipal networks and free WiFi service.

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- Major industry speeches and follow-up media

Click the links above for details ↑

Media, the Mayor, city officials and partners were invited to celebrate One Zone™'s official service launch and the kick-off of the six-month free trial period. The event – held at the Toronto Stock Exchange Broadcast Centre in the heart of the City's financial district, also the heart of the One Zone™ network – provided media with the opportunity to try the service first-hand in an open environment.

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- Major industry speeches and follow-up media

Click the links above for details ↑

Toronto Hydro Telecom Inc. President, Dave Dobbin, delivered the keynote address at the Canadian Telecommunications Forum in Ottawa in October 2006. The speech was part of a lobbying strategy designed to push for regulatory change in the area of accessibility to broadband spectrum – a key plank in Toronto Hydro Telecom Inc.'s future growth strategy for the One Zone™ network. Media coverage of the speech was carried in both the local and national editions of the *National Post*.

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Results

Toronto Hydro Telecom Inc. effectively created awareness of the One Zone™ project and successfully managed related public affairs issues. The first announcement alone garnered 45 million media impressions, encouraged discussion in online chat rooms and attracted inquiries from around the world. Media maintained an interest in the progress of the network throughout the course of the year, and overall public interest in the service resulted in over 40,000 usernames and passwords being issued during the free trial period.

- ☑ **45 million** media impressions
- ☑ On-line discussion
- ☑ International inquiries
- ☑ **40,000** usernames and passwords issued

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TORONTO HYDRO CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2006

The following discussion and analysis should be read in conjunction with the audited consolidated financial statements and accompanying notes of Toronto Hydro Corporation (the "Corporation") as at and for the year ended December 31, 2006 (the "Consolidated Financial Statements"). The Consolidated Financial Statements are prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed by the Ontario Energy Board (the "OEB") and are presented in Canadian dollars.

Business of Toronto Hydro

The Corporation is a holding company, which wholly-owns the following subsidiaries:

- *Toronto Hydro-Electric System Limited* ("LDC") – which distributes electricity;

- *Toronto Hydro Energy Services Inc.* ("TH Energy") – which provides street lighting and expressway lighting services and develops energy efficiency products and services. In 2006, TH Energy also managed a portfolio of electricity contracts (the last of which expired on December 31, 2006), and operated a water heater rental business (the assets comprising the water heater rental business were sold on February 8, 2007). See notes 15, 23 and 26 to the Consolidated Financial Statements; and

- *Toronto Hydro Telecom Inc.* ("Telecom") – which provides fibre optic cable capacity and manages data communications services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, which delivers electricity to approximately 678,000 customers located in the City of Toronto. LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in Ontario. The business of LDC is regulated by the OEB which has broad powers relating to licensing, standards of conduct and service and the regulation of rates charged by LDC and other electricity distributors in Ontario.

TH Energy owns and operates street lighting and expressway lighting systems located in the City of Toronto and is engaged in the sale of energy efficiency products and services to commercial and industrial customers.

Telecom is a provider of "dark" fibre optic capacity and data communications services to telecommunications carriers, business customers and large institutions in the City of Toronto. Telecom owns a network of fibre optic cable located in ducts, on poles and in other parts of the electricity distribution system of LDC. The network is currently connected to over 490 buildings located in the City of Toronto.

The sole shareholder of the Corporation is the City of Toronto (the "City").

Electricity Distribution – Industry Overview

On May 1, 2002, the Province opened Ontario's wholesale and retail markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Open Access").

Since the commencement of Open Access, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ("IESO") and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfil obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

- *Electricity Price and Related Rebates* – The electricity price and related rebates represent a pass through of the commodity cost of electricity.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

  The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

- *Retail Transmission Rate* – The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

- *Wholesale Market Service Charge* – The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

Market participants (including distributors and retailers) are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation and its subsidiaries are exempt from tax under the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)*, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation and each of its subsidiaries is derived from activities carried on outside the municipal geographical boundaries of the City.

The Corporation and each of its subsidiaries is a "municipal electricity utility" ("MEU") for purposes of the payment in lieu of corporate taxes ("PILs") regime contained in the *Electricity Act, 1998*. The *Electricity Act, 1998* provides that a MEU that is exempt from tax under the *Income Tax Act (Canada)* and the *Corporations Tax Act*

(Ontario) is required to make, for each taxation year, a PILs to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

Selected Consolidated Financial Data

The selected consolidated financial data presented below should be read in conjunction with the Consolidated Financial Statements.

Year ended December 31, (in thousands of dollars, except for per share amounts)	2006 $	2005 $	Change $	Change %
Consolidated Statement of Operations Data [1]				
Revenues	2,247,008	2,606,272	(359,264)	(13.78%)
Costs				
Purchased power and other	1,705,845	2,059,789	(353,944)	(17.18%)
Operating expenses	194,216	191,185	3,031	1.59%
Depreciation and amortization	137,344	131,595	5,749	4.37%
	2,037,405	2,382,569	(345,164)	(14.49%)
Income before interest, other and provision for PILs	209,603	223,703	(14,100)	(6.30%)
Interest income	17,726	14,116	3,610	25.57%
Interest expense				
Long-term debt	(75,894)	(80,403)	4,509	5.61%
Other interest	(2,902)	(2,700)	(202)	(7.48%)
Other	89	5,040	(4,951)	(98.23%)
Income before provision for PILs	148,622	159,756	(11,134)	(6.97%)
Provision for PILs	58,403	68,839	(10,436)	(15.16%)
Income from continuing operations	90,219	90,917	(698)	(0.77%)
Income from discontinued operations – net of tax [2]	2,178	1,528	650	42.54%
Net income	92,397	92,445	(48)	(0.05%)
Basic and fully diluted net income per share from continuing operations	90,219	90,917	(698)	(0.77%)
Basic and fully diluted net income per share from discontinued operations	2,178	1,528	650	42.54%
Basic and fully diluted net income per share	92,397	92,445	(48)	(0.05%)

Notes:

(1) Amounts reflect reclassification for discontinued operations. See note 23 to the Consolidated Financial Statements.
(2) Consists of discontinued operations for water heaters. See note 23 to the Consolidated Financial Statements.

As at December 31, (in thousands of dollars)		
	2006 $	2005 $
Consolidated Balance Sheet Data [1]		
Total assets	2,591,706	2,819,258
Current liabilities	555,105	941,211
Long-term liabilities	1,144,537	1,032,180
Total liabilities	1,699,642	1,973,391
Shareholder's equity	892,064	845,867
Total liabilities and shareholder's equity	2,591,706	2,819,258

Note:

(1) Includes discontinued operations. See note 23 to the Consolidated Financial Statements.

Results of Operations

Net Income

Net income was $92.4 million in 2006 and 2005. Unfavourable variances were noted in net revenues ($5.3 million), operating expenses ($3.0 million), depreciation and amortization expense ($5.7 million) and other ($5.0 million). These unfavourable variances were offset by decreased net interest expense ($7.9 million), decreased provision for PILs ($10.4 million) and increased income from discontinued operations ($0.7 million).

Net Revenues

Net revenues (revenues minus the cost of purchased power and other) were $541.2 million in 2006 compared to $546.5 million in 2005. The decrease was primarily due to decreased net revenues at TH Energy ($5.8 million) and LDC ($5.5 million) partially offset by increased net revenues at Telecom ($5.4 million).

At TH Energy, the decrease in net revenues was primarily due to lower contributions from the remaining activities of the electricity retail business which concluded on December 31, 2006 ($17.8 million), partially offset by increased revenue from street lighting and expressway lighting services provided to the City under the terms of a new service agreement entered into as part of the purchase of the street lighting and expressway lighting assets from the City on December 31, 2005 ($12.1 million).

At LDC, the decrease in net revenues for the year ended December 31, 2006 was mainly due to lower distribution revenue from decreased consumption (26,437 GWh compared to 27,282 GWh) attributable to weather and Conservation and Demand Management ("CDM") programs ($13.7 million), a decrease in distribution rates following the OEB's decision on LDC's 2006 rate application regarding interest payable to related parties ($11.8 million), and a reduction of recoverability for PILs related to the elimination of Large Corporation Tax ($1.7 million). LDC's decrease in net revenues was partially offset by higher revenue recognition from CDM programs in 2006 ($14.2 million) and changes in allowable cost recovery stemming from the OEB's decision on 2006 rate application ($7.5 million).

At Telecom, the increase in net revenues was primarily due to increased margin from the sale of data managed services.

Expenses

Operating expenses were $194.2 million in 2006 compared to $191.2 million in 2005. The increase in operating expenses was primarily due to higher deferral of pension and regulatory costs at LDC for 2005 prior to inclusion of these costs in distribution rates effective May 1, 2006 stemming from the OEB's decision into LDC's 2006 rate application ($6.4 million), increased operating spending on CDM programs ($3.9 million), partially offset by lower property taxes ($6.7 million) mainly from realized gains on appeals related to 2002 to 2006 assessments.

Depreciation and amortization expense was $137.3 million in 2006 compared to $131.6 million in 2005. The increase was primarily due to the depreciation of street lighting and expressway lighting assets purchased from the City by TH Energy at the end of 2005.

Net interest expense was $61.1 million in 2006 compared to $69.0 million in 2005. The decrease was primarily due to lower interest expense in respect of the City Promissory Note commencing May 1, 2006 ($4.5 million) (see "Corporate Developments – Amended and Restated City Note") and higher interest received on short-term investments.

Other

Included in Other are amounts primarily relating to gains on disposals of property, plant and equipment. Other was $0.1 million in 2006 compared to $5.0 million in 2005. The decrease was due to gains realized in 2005 on disposals of excess properties at LDC ($2.4 million) and dark fibre assets at Telecom ($2.6 million).

Provision for PILs

Provision for PILs was $58.4 million in 2006 compared to $68.8 million in 2005. The decrease in the provision for PILs was primarily due to higher earnings before taxes in 2005 and lower temporary differences in LDC resulting from deductions of capital cost allowance and depreciation on fixed assets in LDC.

Discontinued Operations

In November 2006, the Board of Directors of TH Energy approved a plan to sell the water heater business. The results of operations and financial position of this business segment have been segregated and are presented as discontinued operations.

Income from discontinued operations was $2.2 million in 2006 compared to $1.5 million in 2005. The increase was primarily due to lower depreciation costs from lower asset book value ($1.1 million), partially offset by higher operating expenses related to marketing efforts ($0.5 million).

On February 8, 2007, TH Energy sold its water heater business to Consumers' Waterheater Income Fund for cash consideration of $40.8 million subject to post closing adjustments and transaction costs. See notes 23 and 26 to the Consolidated Financial Statements.

Quarterly Results of Operations

The tables below present unaudited quarterly consolidated financial information of the Corporation for 2006 and 2005 and reflect discontinued operations relating to water heaters. See note 23 to the Consolidated Financial Statements.

2006 quarter ended, (in thousands of dollars)	December 31 $	September 30 $	June 30 $	March 31 $
Revenues	549,931	598,581	534,930	563,566
Costs	499,836	541,858	487,257	508,454
Income from continuing operations	22,054	28,197	17,721	22,247
Net income	22,783	28,894	18,161	22,559

2005 quarter ended, (in thousands of dollars)	December 31 $	September 30 $	June 30 $	March 31 $
Revenues	636,206	772,121	586,972	610,973
Costs	591,429	713,039	520,859	557,242
Income from continuing operations	22,153	18,842	29,380	20,542
Net income	22,501	19,354	29,754	20,836

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, short-term bank financing, interest income and debt capital market borrowings.

The Corporation does not believe that equity contributions from the City, its sole shareholder, will constitute a source of capital. In addition, the Corporation is not aware of any plan or decision by the City to permit the Corporation to sell equity to the public or other investors.

Liquidity and Capital Resources Year Ended December 31, (in thousands of dollars)	2006 $	2005 $
Cash and cash equivalents, beginning of period	448,370	386,625
Net cash provided by operating activities	112,728	325,087
Net cash used in investing activities	(188,602)	(174,722)
Net cash used in financing activities	(45,547)	(89,947)
Net cash provided by discontinued operations (1)	575	1,327
Cash and cash equivalents, end of period	327,524	448,370

Note:

(1) Consists of discontinued operations for water heaters. See note 23 to the Consolidated Financial Statements.

Cash Provided by Operating Activities

Cash provided by operating activities was $112.7 million in 2006 compared to $325.1 million in 2005. The decrease was primarily due to an unfavourable variance in accounts payable and accrued liabilities at LDC due to the payment in 2006 of rebates received at the end of 2005 ($174.9 million) and increased payments for PILs in 2006 from revisions to projected tax liabilities ($45.5 million), an unfavourable variance in the aggregate of accounts receivable and unbilled revenue at TH Energy due to reduced electricity activities ($39.8 million) and an unfavourable variance in deferred revenue primarily due to increased CDM initiatives at LDC ($34.6 million).

These variances were partially offset by a favourable variance in the aggregate of accounts receivable and unbilled revenue at LDC due to timing differences in the collection of large commercial customers at the end of 2006 ($53.8 million) and a favourable variance in electricity mark-to-market assets and liabilities at TH Energy resulting from the expiration of the electricity retail portfolio ($25.1 million).

Revolving Credit Facility

The Corporation is a party to a revolving credit facility agreement dated May 5, 2005 pursuant to which the Corporation may borrow up to $500 million, of which up to $175 million is available in the form of letters of credit. As at December 31, 2006, no borrowings for working capital were outstanding and letters of credit in the amount of $81.6 million had been issued. See note 9 to the Consolidated Financial Statements.

Operating Liquidity and Capital Resource Requirements

The Corporation's primary liquidity and capital resource requirements are for capital expenditures to maintain and improve the electricity distribution system of LDC, cost of power expense, interest expense and prudential requirements and third party credit support.

Cash Used in Investing Activities

Cash used in investing activities was $188.6 million in 2006 compared to $174.7 million in 2005. The increase was primarily due to an increase in regulatory assets from smart meter activities and settlement of variance accounts in LDC ($24.8 million), an increase in the purchase of property, plant and equipment at LDC to improve electricity distribution assets ($35.4 million), at TH Energy to improve street lighting and expressway lighting assets ($4.3 million) and at Telecom for the reinforcement of the core network and the deployment of the new Wi-Fi network ($3.4 million). These variances were partially offset by the investment of $60 million made by TH Energy in 2005 for the purchase of the street lighting and expressway lighting assets from the City.

Capital Expenditures

The following table summarizes the Corporation's capital expenditures for the years indicated.

Year Ended December 31, (in thousands of dollars)	2006 $	2005 $
Capital Expenditures from Continuing Operations		
LDC		
Distribution system	131,389	113,333
Technology assets	21,880	10,119
Other [1]	14,416	8,808
	167,685	132,260
Other [2]	17,622	68,095
Total capital expenditures	185,307	200,355
Capital Expenditures from Discontinued Operations		
Water heaters	3,865	3,638

Notes:

(1) Consists of vehicles, other work-related equipment, furniture and office equipment.
(2) Includes capital expenditures relating to TH Energy and Telecom.

Cash Used in Financing Activities

Cash used in financing activities was $45.5 million in 2006 compared to $89.9 million in 2005. The decrease was primarily due to a decrease in dividends paid ($21.8 million) and the reclassification of a large portion of customer deposits to long-term assets in 2006 ($21.9 million).

Prudential Requirements and Third Party Credit Support

In order to mitigate the risk of payment default, wholesale market participants are required to provide credit support for their obligations to the IESO in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings. A market participant's prudential requirements are determined by the IESO based on the participant's "maximum net exposure", subject to permitted reductions resulting from, among other things, good payment history, credit rating or, in the case of distributors, prudential support collected from retailers or customers.

In addition to prudential requirements, counterparties under bilateral contracts for the purchase and sale of electricity contracts may require parental guarantees or other forms of credit support. Also, electricity distributors may require retailers to maintain security arrangements (including letters of credit, surety bonds, cash deposits or lock-box arrangements) under terms prescribed by the OEB to protect against credit risk.

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purposes of enabling them to carry on their businesses up to an aggregate amount of $500 million.

As at December 31, 2006, the Corporation had issued $56.5 million of parental guarantees on behalf of TH Energy in support of prudential requirements and obligations under bilateral contracts for the purchase and sale of electricity. The Corporation has also issued a parental guarantee to the City as part of an agreement by the City to purchase electricity at a fixed price from TH Energy. The value of the parental guarantee to the City was nil at December 31, 2006. See note 16 to the Consolidated Financial Statements.

Dividends

The shareholder direction adopted by the City with respect to the Corporation provides that the board of directors of the Corporation will use its best efforts to ensure the Corporation meets certain financial performance standards, including those relating to credit rating and dividends. Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year equal to the greater of $25 million or 50% of the Corporation's net income for the year. The dividends are not cumulative and are payable as follows:

- $6 million on the last business day of each of the first three fiscal quarters during the year;
- $7 million on the last business day of the fiscal year; and
- the amount, if any, by which 50% of the Corporation's net income for the year exceeds $25 million, within ten calendar days after the board of directors of the Corporation approves the Corporation's Consolidated Financial Statements for the year.

The board of directors of the Corporation declared and paid dividends totalling $46.2 million in 2006 and $68.0 million in 2005.

On March 1, 2007, the board of directors of the Corporation declared dividends in the amount of $27.2 million. The dividends are comprised of a $21.2 million payment for 2006 net income, payable to the City on March 9, 2007, and a $6.0 million payment in connection with the first quarter of 2007, payable to the City on March 30, 2007.

Corporate Developments

Appointments

On November 29, 2006, Anthony Haines was appointed President of LDC.

On December 6, 2006, Gordon Perks was appointed as a Director of the Corporation and David Shiner and Bill Saundercook were reappointed as Directors of the Corporation, each for a term of office that shall end on December 31, 2008.

Changes in Business

TH Energy operated a water heater rental business until February 8, 2007, at which time the business was sold to The Consumers' Waterheater Income Fund. See notes 23 and 26 to the Consolidated Financial Statements.

In December 2002, TH Energy ceased electricity retailing activities in respect of new customers following the implementation of price protection under the *Electricity Pricing, Conservation and Supply Act,* 2002. Remaining contracts and portfolio obligations were managed to expiration on December 31, 2006. See note 15 to the Consolidated Financial Statements.

Medium-Term Note Program

On January 13, 2006, the Corporation filed a short form base shelf prospectus in connection with the establishment of a medium-term note program ("MTN Program"). Under the terms of the MTN Program, the Corporation may offer and issue, from time to time, unsecured debentures in one or more series in an aggregate principal amount of up to $1 billion during the twenty-five months following the date of the prospectus. The debentures issuable under the MTN Program have been assigned a rating of "A" with a stable trend by DBRS and a preliminary rating of "A-" by S&P. As at December 31, 2006, no debentures had been issued under the MTN Program.

Amended and Restated City Note

On September 5, 2006, the Corporation announced that it and the City had amended and restated the outstanding $980.2 million promissory note between the Corporation and the City (the "City Note") effective

May 1, 2006 by fixing the interest rate at 6.11% (the same interest rate payable on the Corporation's outstanding senior unsecured debentures) and establishing an agreed repayment schedule ($245.1 million on the last business day before each of December 31, 2007, December 31, 2009 and December 31, 2011 and on May 6, 2013). Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year. A copy of the amended and restated City Note is available at www.sedar.com. See note 11 to the Consolidated Financial Statements.

Ministry of Finance Tax Audit

The Ministry of Finance is currently carrying out a tax audit of the Corporation and its subsidiaries. Certain filing positions for PILs taken by the Corporation and its subsidiaries may be challenged on the audit. This may result in a material increase in the Corporation's reported tax obligations upon reassessment. As the audit has not yet been completed, management is not able to determine the impact, if any, of the audit on the Consolidated Financial Statements or the Corporation's tax reserves. The Corporation adjusts its tax reserves when there is sufficient information available, or when an event occurs requiring a change to the reserves.

Distribution Rates

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39.8 million, representing the third and final adjustments necessary to achieve a market-based rate of return of 9.88%. The rate increase was effective as of April 1, 2005 and subjected the LDC to a financial commitment to invest $39.8 million in CDM activities by September 2007.

In April 2006, the OEB approved a decrease in distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $58.0 million. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980.2 million promissory note between LDC and the Corporation from 6.8% to 5% per annum.

On January 26, 2007, LDC filed an Annual Rate Adjustment Application for 2007 Rates as directed to by the OEB. In accordance with the OEB's Incentive Regulation Model, LDC has sought authorization to increase its distribution rates by 0.4% on May 1, 2007.

Smart Meters

On June 13, 2006, the Province issued draft regulations clarifying the technical details of advanced metering infrastructure and data management. In support of the Province's decision to install smart meters throughout Ontario by 2010, LDC launched its smart meter project in 2006. The project objective is to install 711,000 smart meters and the supporting infrastructure by the end of 2009. LDC had installed 193,000 meters at December 31, 2006 and will use the experience gained from this initiative as an opportunity to further develop and test the new tools, processes, and network infrastructure to support the mass deployment of these smart meters.

On May 1, 2006, LDC implemented new distribution rates which included charges for smart meters of $0.47 per month for each residential customer and $1.04 per month for all other customers. The charges are the first part of the funding for LDC's smart meter program. Consistent with the OEB's direction, LDC has deferred capital expenditures, operating expenditures, and revenues relating to smart meters in regulatory asset accounts. When LDC files its application to clear the 2006 smart meter balances, the $0.47 and $1.04 riders will be removed (and replaced by new rate riders, if approved by the OEB). See note 7 to the Consolidated Financial Statements.

OEB Proposals for Multi-Year Electricity Rate Setting Plan

On June 19 and July 25, 2006, the OEB began a generic licence amendment proceeding that was intended to effect changes to the allowable cost of capital and to effect a multi-year electricity distribution rate setting plan via incentive regulation mechanisms for distributors. LDC responded to both proposals in writing, and participated in technical conferences held in August and September. In December 2006, in the interests of implementing

distribution rate changes for 2007 in a timely manner, the OEB discontinued its examination into LDCs' allowable cost of capital and second-generation incentive regulation mechanism.

Consumers' Gas Decision

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada ruled that The Consumers' Gas Company ("Consumers' Gas") was required to repay that portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement. However, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff and to receive lawyer's fees in connection with such efforts. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below and in the Corporation's annual information form, in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario MEU's under the Class Proceedings Act, 1992 seeking $500.0 million in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intentions to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the *Class Proceedings Act, 1992* seeking $64.0 million in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is also at a preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the Criminal Code is fact specific in each circumstance. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares of which 1,000 common shares are issued and outstanding as at the date hereof.

Services Provided to the City

Subsidiaries of the Corporation provide certain services to the City at commercial rates, including street lighting and maintenance services. In addition, the City and its agencies have entered into energy management contracts with TH Energy. See note 19 to the Consolidated Financial Statements.

Risks and Uncertainties

The financial performance of the Corporation is subject to a variety of risks and uncertainties including those described below:

Regulatory Uncertainty

The OEB regularly conducts consultations with interested stakeholders with respect to a number of areas which may affect electricity distributors.

The continuing restructuring of Ontario's electricity industry and other regulatory developments may affect the distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation. In particular, there can be no assurance that:

- the OEB may not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through distribution rates;
- the OEB will not permit competitors to provide distribution services in a distributor's licensed area;
- the OEB will allow recovery for revenue lost as a consequence of the emergence and adoption of new technologies such as distributed generation, or unanticipated effects of conservation and demand management;
- parts of the LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Changes to any of the laws, rules, regulations or policies applicable to the businesses carried on by the Corporation could have a significant impact on the Corporation. There can be no assurance that the Corporation will be able to comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings which may have a material adverse effect on the Corporation.

Additional Debt Financing

The Corporation expects to borrow to repay the City Note when required to do so under the terms of the City Note. See note 11 to the Consolidated Financial Statements. The Corporation's ability to arrange sufficient and cost-effective debt financing to repay the City Note and for general corporate purposes (including credit support for prudential requirements) could be adversely affected by a number of factors, including the regulatory environment in Ontario, the Corporation's results of operations and financial condition, financial market conditions, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities, and general economic conditions.

Electricity Consumption

LDC's distribution rates typically comprise a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

Credit Risk

LDC is subject to credit risk with respect to customer non-payment. LDC is permitted to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (including letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB) under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection.

In the event of an actual payment default and attendant bad debt expense incurred by LDC, roughly 80% of the expense would be related to commodity and transmission costs, and the remainder to LDC's distribution revenue. Accordingly, while LDC will be liable for the full amount of the default, there can be no assurance that the OEB will allow recovery of the bad debt expense from remaining customers. Rather, it is expected that the OEB will examine LDC's application for claiming bad debt expenses on a case-by-case basis. See note 15 to the Consolidated Financial Statements.

Condition of Distribution Assets

The Corporation's ability to continue to maintain and operate the distribution system reliably and safely in the future will depend on, among other things, the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

Refer to the Corporation's annual information form for more details on risks and uncertainties.

Disclosure and Internal Controls

The President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Corporation, together with management, have established and maintained disclosure controls and procedures of the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. These officers evaluated the effectiveness of the design and operation of disclosure controls and procedures as of December 31, 2006 and, based on that evaluation, have concluded that these controls are effective in providing such reasonable assurance.

The CEO and CFO, together with management, have also evaluated the design of internal controls over financial reporting of the Corporation as of December 31, 2006 in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. Based on that evaluation, these officers have concluded that the design of these controls is effective to provide such reasonable assurance.

During the quarter ending December 31, 2006, there were no changes to the Corporation's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Significant Accounting Policies

The Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed by the OEB, and are presented in Canadian dollars. In preparing the Consolidated Financial Statements, management of the Corporation makes estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the Consolidated Financial Statements and the reported amounts of revenues and expenses for the periods covered thereby. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance. The significant accounting policies of the Corporation are summarized in note 4 to the Consolidated Financial Statements.

Effective June 30, 2006, the Corporation adopted Emerging Issue Committee Abstract EIC-159 - "Conditional Asset Retirement Obligations" ["EIC-159"]. EIC-159 requires an entity to recognize a liability for the fair value of an asset retirement obligation ["ARO"] even though the timing or method of settlement is conditional on future events. The Corporation has identified conditional AROs and recognized a liability amounting to $1.6

million at year-end. The change has been accounted for prospectively as information is not available to allow it to be accounted for retrospectively. See note 4 to the Consolidated Financial Statements.

In April 2005, the Canadian Institute of Chartered Accountants released three Handbook Sections relating to financial instruments: 1530 – "Comprehensive Income", 3855 – "Financial Instruments – Recognition and Measurement" and 3865 – "Hedges" effective for annual and interim periods beginning on or after October 1, 2006. These new Sections establish standards for the recognition and measurement of financial instruments. The Corporation is currently evaluating the impact of these standards on its financial statements.

In December 2006, the Canadian Accounting Standards Board announced that as of March 31, 2008, they will be making a final decision on the date in which publicly accountable enterprises will be required to change over to International Financial Reporting Standards ("IFRS"). At this time, it is anticipated that by 2011 Canadian GAAP will be substantially the same as IFRS. Until the change over is finalized, companies will continue to describe their basis of reporting as Canadian GAAP.

Forward-Looking Information

Certain information included herein constitutes "forward-looking information". Forward-looking information means disclosure regarding possible events, conditions or results that is based on assumptions about future economic conditions and courses of action. In some cases, forward looking information can be identified by terminology such as "may", "will", "should", "expect", "anticipate", "believe", "estimate", "predict", "potential", "budget", "continue" or the negative of these terms or other comparable terminology. In addition, certain information included herein may contain forward-looking information attributable to third parties. Although the Corporation believes that it has a reasonable basis for the forward-looking information included herein, such information is subject to a number of risks and uncertainties that may cause actual events, conditions or results to differ materially from those contemplated by the forward-looking information. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, the ratings assigned to the Corporation and its debt securities by rating agencies, general economic conditions and weather. The Corporation does not undertake any obligation to update publicly or to revise any of the forward-looking information included herein after the date hereof, whether as a result of new information, future events or otherwise.

Additional Information

The information included herein reflects material events up to March 1, 2007, the date on which Consolidated Financial Statements of the Corporation were approved by the Corporation's board of directors.

Additional information with respect to the Corporation (including its annual information form and annual report) is available on the Canadian Securities Administrators' web-site at www.sedar.com.

Toronto, Canada

March 1, 2007

The accompanying Consolidated Financial Statements of Toronto Hydro Corporation ("the Corporation") and the financial information in the Ontario Securities Commission reporting package are the responsibility of management and have been prepared by management in accordance with Canadian generally accepted accounting principles. Where alternative accounting methods exist, management has selected those it considers most appropriate in the circumstances. The significant accounting policies followed by the Corporation are described in the summary of significant accounting policies contained in Note 4 of the Consolidated Financial Statements. The preparation of financial statements necessarily involves the use of estimates based on management's judgments, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. The consolidated financial statements have been prepared within reasonable limits of materiality in light of information available up to March 1, 2007.

Management maintains a system of internal control, which is designed to provide reasonable assurance that the financial information is relevant, reliable, and accurate, and the Corporation's assets are safeguarded and transactions executed in accordance with management's authorization. The system includes formal policies and procedures and appropriate delegation of authority and segregation of responsibilities within the organization.

The Consolidated Financial Statements have been audited by Ernst & Young, LLP, independent external auditors appointed by the Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report outlines the scope of their examination and their opinion.

The Board of Directors is responsible for overseeing management in the performance of its financial reporting responsibilities and also the responsibility for reviewing and approving the financial information included in the Ontario Securities Commission reporting package. The Audit Committee composed of independent directors, meets periodically with management and the external auditors to satisfy itself that each group has properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors have direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

David S. O'Brien
President and Chief Executive Officer

Jean-Sebastien Couillard
Chief Financial Officer

Toronto, Ontario
March 1, 2007

Consolidated Financial Statements

Toronto Hydro Corporation

December 31, 2006

Consolidated Financial Statements

Toronto Hydro Corporation

December 31, 2006

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AUDITORS' REPORT

To the Shareholder of
Toronto Hydro Corporation

We have audited the consolidated balance sheets of **Toronto Hydro Corporation** [the "Corporation"] as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Toronto, Canada,
February 21, 2007 [except as to note 26,
which is as of March 1, 2007].

Chartered Accountants

Toronto Hydro Corporation

CONSOLIDATED BALANCE SHEET

[in thousands of dollars]

As at December 31	2006 $	2005 $
ASSETS		
Current		
Cash and cash equivalents	**327,524**	448,370
Accounts receivable, net of allowance for doubtful accounts	**218,452**	174,499
Unbilled revenue	**216,857**	271,367
Inventories	**22,458**	18,189
Prepaid expenses	**2,277**	2,168
Electricity mark-to-market assets *[note 15]*	**-**	113,297
Future income tax assets *[note 17]*	**791**	33,195
Assets from discontinued operations *[note 23]*	**12,098**	-
Total current assets	**800,457**	1,061,085
Property, plant and equipment, net *[note 5]*	**1,656,868**	1,624,741
Intangible assets, net *[note 6]*	**49,266**	41,926
Regulatory assets *[note 7]*	**66,528**	63,752
Other assets *[note 8]*	**2,578**	5,490
Future income tax assets *[note 17]*	**16,009**	22,264
Total assets	**2,591,706**	2,819,258
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**284,869**	423,780
Current portion of other liabilities *[note 10]*	**16,952**	39,210
Current portion of deferred revenue	**7,320**	20,423
Current portion of promissory note payable *[note 11]*	**245,058**	330,000
Electricity mark-to-market liabilities *[note 15]*	**-**	86,875
Future income tax liabilities *[note 17]*	**-**	40,923
Liabilities from discontinued operations *[note 23]*	**906**	-
Total current liabilities	**555,105**	941,211
Long-term liabilities		
Debentures *[note 11]*	**225,000**	225,000
Promissory note payable *[note 11]*	**735,173**	650,231
Post-employment benefits *[note 12]*	**134,682**	125,415
Regulatory liabilities *[note 7]*	**11,840**	13,297
Other liabilities *[note 13]*	**3,949**	9,077
Asset retirement obligations *[note 14]*	**7,581**	5,691
Customers' advance deposits	**25,944**	2,900
Future income tax liabilities *[note 17]*	**368**	569
Total long-term liabilities	**1,144,537**	1,032,180
Total liabilities	**1,699,642**	1,973,391
Commitments and contingencies *[notes 20 and 21]*		
Shareholder's equity		
Share capital *[note 18]*	**567,817**	567,817
Retained earnings	**324,247**	278,050
Total shareholder's equity	**892,064**	845,867
Total liabilities and shareholder's equity	**2,591,706**	2,819,258

ON BEHALF OF THE BOARD:

Clare R. Copeland, Director

L. Ross Cullingworth, Director

Toronto Hydro Corporation

CONSOLIDATED STATEMENT OF INCOME

[in thousands of dollars, except for per share amounts]

Year ended December 31	**2006** **$**	**2005** **$**
Revenues	**2,247,008**	2,606,272
Costs		
Purchased power and other	**1,705,845**	2,059,789
Operating expenses	**194,216**	191,185
Depreciation and amortization	**137,344**	131,595
	2,037,405	2,382,569
Income before interest, other and provision for payments in lieu of corporate taxes	**209,603**	223,703
Interest income	**17,726**	14,116
Interest expense		
Long-term debt	**(75,894)**	(80,403)
Other interest	**(2,902)**	(2,700)
Other	**89**	5,040
Income before provision for payments in lieu of corporate taxes	**148,622**	159,756
Provision for payments in lieu of corporate taxes *[note 17]*	**58,403**	68,839
Income from continuing operations	**90,219**	90,917
Income from discontinued operations - net of tax *[note 23]*	**2,178**	1,528
Net income	**92,397**	92,445
Basic and fully diluted net income per share from continuing operations *[note 22]*	90,219	90,917
Basic and fully diluted net income per share from discontinued operations *[note 22]*	2,178	1,528
Basic and fully diluted net income per share	**92,397**	92,445

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31	**2006** **$**	**2005** **$**
Retained earnings, beginning of year	**278,050**	253,605
Net income	**92,397**	92,445
Dividends *[note 18]*	**(46,200)**	(68,000)
Retained earnings, end of year	**324,247**	278,050

Toronto Hydro Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	2006 $	2005 $
OPERATING ACTIVITIES		
Income from continuing operations	**90,219**	90,917
Adjustments for non-cash items		
Depreciation and amortization	**137,344**	131,595
Net change in other assets and liabilities	**(3,191)**	1,878
Electricity mark-to-market assets and liabilities	**26,422**	1,274
Post-employment benefits	**9,267**	7,298
Future income taxes	**(2,488)**	(3,121)
Gain on disposals of property, plant and equipment	**(89)**	(5,040)
Changes in non-cash working capital balances		
Decrease (increase) in accounts receivable	**(44,003)**	9,080
Decrease (increase) in unbilled revenue	**54,510**	(25,245)
Decrease (increase) in inventories	**(4,269)**	1,719
Decrease (increase) in prepaid expenses	**(60)**	45
Increase (decrease) in accounts payable and accrued liabilities	**(137,787)**	93,045
Increase (decrease) in deferred revenue	**(13,179)**	20,423
Increase in current portion of other liabilities	**32**	1,219
Net cash provided by operating activities	**112,728**	325,087
INVESTING ACTIVITIES		
Purchase of property, plant and equipment	**(166,806)**	(192,241)
Purchase of intangible assets	**(18,501)**	(8,114)
Net change in regulatory assets and liabilities	**(4,233)**	20,548
Proceeds on disposal of property, plant and equipment	**938**	5,085
Net cash used in investing activities	**(188,602)**	(174,722)
FINANCING ACTIVITIES		
Increase (decrease) in customers' advance deposits	**1,835**	(20,081)
Repayment of capital lease liability	**(1,182)**	(1,866)
Dividends paid *[note 18]*	**(46,200)**	(68,000)
Net cash used in financing activities	**(45,547)**	(89,947)
Net cash provided by (used in) continuing operations	**(121,421)**	60,418
Net cash provided by discontinued operations	**575**	1,327
Net increase (decrease) in cash and cash equivalents during the year	**(120,846)**	61,745
Cash and cash equivalents, beginning of year	**448,370**	386,625
Cash and cash equivalents, end of year	**327,524**	448,370
Supplementary cash flow information		
Total interest paid	77,442	81,657
Payments in lieu of corporate income taxes	106,771	74,780

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2006

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the Business Corporations Act (Ontario) along with two wholly-owned subsidiary companies, Toronto Hydro-Electric System Limited ["LDC"] and Toronto Hydro Energy Services Inc. ["TH Energy"]. The incorporation was required in accordance with the provincial government's Electricity Act, 1998.

Under the terms of By-law No. 374-1999 of the City of Toronto ["Transfer By-law"] made under section 145 of the Electricity Act, 1998 and in accordance with continuity of interest accounting, the former Toronto Hydro-Electric Commission and the City of Toronto [the "City"] transferred, at book value, their assets and liabilities [effective July 1, 1999] and employees [effective January 1, 2000] associated with:

[a] electricity distribution to LDC in consideration for the issuance of equity securities of LDC and long-term notes payable to the City; and

[b] electricity generation, co-generation and energy services to TH Energy in consideration for the issuance of equity securities of TH Energy.

The equity securities of LDC and TH Energy were subsequently transferred by the City to the Corporation in consideration for the issuance of equity securities of the Corporation to the City.

Certain surplus real property assets and cash funds were excluded from the transfer and were retained by the City. In addition, the long-term debt incurred by the City on behalf of the former Toronto Hydro-Electric Commission was excluded from the liabilities transferred and was retained by the City.

The book value of the assets transferred at July 1, 1999 was $1,548,048,000. The principal amount of the long-term notes payable to the City was $980,231,000 and the value of the common shares of the Corporation received by the City was $567,817,000.

The Corporation supervises the operations of, and provides corporate and management services and strategic direction to, its subsidiary companies [each of which is listed below, incorporated under the BCA and wholly-owned, directly or indirectly, by the Corporation]:

[a] LDC [incorporated June 23, 1999] – which distributes electricity to customers located in the City and is subjected to rate regulation.

[b] TH Energy [incorporated June 23, 1999] – which owns and operates street lighting and expressway lighting systems located in the City and is engaged in the sale of energy efficiency products and services.

[c] Toronto Hydro Telecom Inc. ["Telecom"] [incorporated September 26, 2000] – which provides fibre optic cable capacity and manages data communications services.

[d] 1455948 Ontario Inc. [incorporated December 21, 2000] – which owns a 50% interest in EBT Express Partnership ["EBT Express"], a joint venture with a wholly-owned subsidiary of Ontario Power Generation Inc. EBT Express owns a 67% controlling interest in The SPi Group, a corporation formed to provide, among other things, centralized electronic data management and transaction services to energy industry participants.

The principal business of the Corporation is the regulated distribution of electricity by LDC.

2. REGULATION

In April 1999, the government of Ontario initiated a restructuring of Ontario's electricity industry. The restructuring was intended, among other things, to facilitate competition in the generation and sale of electricity, to protect the interests of consumers with respect to prices and the reliability and quality of electricity service and to promote economic efficiency in the generation, transmission and distribution of electricity.

The Ontario Energy Board [the "OEB"] has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

[i] *Electricity Price and Related Rebates*. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

[ii] *Distribution Rate*. The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge*. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

3. ELECTRICITY DISTRIBUTION RATES

In connection with the restructuring of Ontario's electricity industry in 1999, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return of 9.88% on the deemed debt to equity structure of LDC of 65:35. The adjustment was being phased in over three adjustment periods to lessen the rate impact on customers. Effective on each of December 1, 2000 and March 1, 2002, the OEB authorized LDC to increase its distribution rates to allow for the recovery of additional annual revenue of $39.8 million.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39.8 million, representing the third and final adjustments necessary to achieve a market-based rate of return of 9.88%. The rate increase was effective as of April 1, 2005 and subjected the LDC to a financial commitment to invest $39.8 million in Conservation and Demand Management ["CDM"] activities by September 2007.

In April 2006, the OEB approved a decrease in the distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $57,956,000, including the new regulatory treatment for revenues relating to smart meters [see *note 7*]. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on deemed equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980,231,000 promissory note between LDC and the Corporation from 6.8% to 5% per annum.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates and other permitted recoveries.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Corporation have been prepared in accordance with Canadian generally accepted accounting principles ["GAAP"], including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ["AP Handbook"] and reflect the significant accounting policies summarized below.

a) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian Institute of Chartered Accountants ["CICA"] Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation" ["AcG-19"], certain costs and variance account balances deemed to be "regulatory assets" or "regulatory liabilities" are reflected separately on LDC's balance sheet until the manner and timing of disposition is determined by the OEB *[note 7]*.

Payments in lieu of corporate taxes

The Corporation and its subsidiaries are exempt from tax under the *Income Tax Act (Canada)* ["ITA"] and the *Corporations Tax Act (Ontario)*, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income and each of its subsidiaries is derived from activities carried on outside the municipal geographical boundaries of the City.

The Corporation and each of its subsidiaries is a "municipal electricity utility" ["MEU"] for purposes of the payments in lieu of corporate taxes ["PILs"] regime contained in the Electricity Act, 1998. The Electricity Act, 1998 provides that a MEU that is exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* is required to make, for each taxation year, a PILs, to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining the respective liabilities for PILs. Accordingly, the Corporation and its subsidiaries were deemed to have disposed of their assets at their then fair market value and to have re-acquired such assets at the same amount. The differences between the financial statement carrying value and tax basis of assets and liabilities were accounted for by the Corporation as follows:

[a] in the case of the Corporation's unregulated businesses, the liability method of accounting was applied in accordance with recommendations of the CICA; and

[b] in the case of the Corporation's regulated electricity distribution business, the taxes payable method of accounting was applied in accordance with recommendations of the CICA and the OEB.

Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arise from temporary differences in the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time.

The OEB's Electricity Distribution Rate Handbooks, issued in March 2000 and May 2005, provide for the recovery of PILs by LDC through annual distribution rate adjustments as permitted by the OEB. The OEB-approved distribution rate for PILs recoveries is based on estimated consumption volumes. The difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs amount up to April 30, 2006, is tracked by

LDC as a variance amount in accordance with OEB guidelines for regulatory assets and with criteria set out in the AP Handbook. Commencing May 1, 2006, any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application are tracked by LDC as variance amounts.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property, plant and equipment of LDC. According to the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Spare transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the AP Handbook, spare transformers are treated as capital assets *[note 5]*, which would be recorded as inventory under Canadian GAAP for unregulated businesses.

c) Cash and cash equivalents

Effective January 1, 2006, the Corporation changed the terms to maturity in the definition of cash equivalents from five months or less to 90 days or less from the date of acquisition. This change resulted in no impact on the audited consolidated financial statements as at December 31, 2006 and 2005.

d) Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on an average cost basis net of the provision for obsolescence.

e) Property, plant and equipment and depreciation

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to "Other" in the Consolidated Statement of Income.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

Buildings	1.7% to 10.0%
Stations	2.9% to 5.0%
Distribution lines	2.5% to 25.0%
Transformers	3.3% to 4.0%
Meters	2.9% to 4.0%
Other capital assets	6.7% to 12.5%
Communications	5.0% to 20.0%
Computer hardware	20.0% to 25.0%
Rolling stock	12.5% to 33.3%
Equipment and tools	10.0%

Construction in progress includes assets not currently in use which are not depreciated.

f) Intangible assets

Intangible assets, which lack physical substance, are stated at cost. Amortization is provided on a straight-line basis over their estimated useful service lives at the following annual rates:

Land rights	2.0%
Computer software	14.0% to 33.0%
Capital contributions	4.0%
Leasehold improvements	Over the remaining lease term

Software in development includes assets not currently in use which are not amortized.

g) Deferred debt issue costs

In 2003, the Corporation incurred debt issue costs arising from the Corporation's debenture offering *[note 8]*. Deferred debt issue costs are included in "Other assets" and represent the unamortized amounts of debt costs arising from the issuance of debt, and other related costs. Deferred debt issue costs are amortized over the period to maturity of the debt on a straight-line basis.

h) Workplace Safety and Insurance Act

The Corporation is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act ["WSIA"]. As a Schedule 1 employer, the Corporation is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

i) Revenue recognition and accounting for financial derivative instruments

LDC

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39,800,000. The rate increase was effective as of April 1, 2005 and is subject to a financial commitment by LDC to spend $39,800,000 in CDM activities by September 2007. The revenue of $39,800,000 was billed to customers over a period of 11-months commencing April 1, 2005. At each reporting date, on a life-to-date basis, to the extent the earned customer revenue exceeds the CDM activity spending, the difference is recorded in the balance sheet as "Deferred revenue".

Other income, which includes revenues from electricity distribution related services, is recognized as the services are rendered.

TH Energy

TH Energy has entered into contracts to provide electricity at fixed prices. Electricity contracts are contracts with fixed notional volumes at fixed prices. These contracts expose TH Energy to changes in market prices of electricity and consumption. To reduce its exposure to these changes, TH Energy purchases wholesale electricity physical bilateral and financial contracts.

TH Energy accounts for notional block contracts and non-designated purchase contracts using the mark-to-market method of accounting. Under the mark-to-market method of accounting, TH Energy records the fair value of the contracts, less related reserves, as mark-to-market assets or liabilities at the time of contract execution. All transactions are recognized on a net basis as mark-to-market revenue. Mark-to-market revenue includes gains or losses on new transactions at origination, unrealized gains and losses from changes in the fair value of contracts, net gains or losses from realized transactions and changes in reserves.

TH Energy records reserves for counter-party credit risk and on-going operational expense to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market assets and liabilities. To the extent possible, TH Energy utilizes market-based data together with quantitative methods to determine the level of reserves.

As at December 31, 2006, all retail and wholesale electricity contracts have concluded. TH Energy has no outstanding contracts as at December 31, 2006.

Energy efficiency products and services revenue is accounted for under the percentage of completion method, with revenue recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident.

Water heater revenue is accounted for when the service is rendered.

TH Energy provides certain services to the City at commercial rates, including street lighting and expressway lighting services. Street lighting and expressway lighting services are recognized when services are rendered.

Telecom

Fibre leasing and data communications services revenues are recognized as services are rendered.

j) Employee future benefits

Pension plan

The Corporation provides a pension plan for its full-time employees through Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Corporation recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension

Employee future benefits other than pension provided by the Corporation include medical and life insurance benefits, accumulated sick leave credits and voluntary exit incentive program liability. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains (losses) over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in the period in which a settlement occurs.

k) Customers' advance deposits

Customers' advance deposits are cash collections from customers to guarantee the payment of energy bills. The customers' advance deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

l) Asset retirement obligations

The Corporation recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in distribution equipment and in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value is determined.

Effective June 30, 2006, the Corporation adopted Emerging Issues Committee Abstract EIC-159 "Conditional Asset Retirement Obligations" ["EIC-159"]. EIC-159 requires an entity to recognize a liability for the fair value of an ARO even though the timing or method of settlement is conditional on future events. The Corporation has identified

conditional AROs and recognized the related liability in 2006. The adoption has been accounted for prospectively as information is not available to allow it to be accounted for retroactively. The fair value of the identified AROs and the change from prior period are determined to be not material to the Corporation's result of operations and financial position.

m) Use of estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or Minister of Finance.

5. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2006			2005		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**4,088**	**—**	**4,088**	4,136	—	4,136
Buildings	**145,281**	**44,016**	**101,265**	144,048	43,332	100,716
Stations	**191,833**	**99,988**	**91,845**	183,155	94,179	88,976
Distribution lines	**2,069,674**	**1,024,020**	**1,045,654**	1,982,918	942,109	1,040,809
Transformers	**493,878**	**264,308**	**229,570**	471,562	247,102	224,460
Meters	**131,886**	**80,032**	**51,854**	127,468	75,721	51,747
Other capital assets	**44,077**	**30,127**	**13,950**	57,506	41,722	15,784
Communications	**73,041**	**45,629**	**27,412**	61,241	39,290	21,951
Computer hardware	**39,511**	**35,237**	**4,274**	36,593	33,436	3,157
Rolling stock	**57,237**	**44,243**	**12,994**	51,424	40,990	10,434
Equipment and tools	**33,168**	**23,488**	**9,680**	28,086	22,232	5,854
Construction in progress	**64,282**	**—**	**64,282**	56,717	—	56,717
	3,347,956	**1,691,088**	**1,656,868**	3,204,854	1,580,113	1,624,741

At December 31, 2006, spare transformers with carrying amounts of $5,486,000 [2005 - $4,767,000], are included in "Property, plant and equipment, net" *[note 4[b] "Spare transformers"]*. In the absence of rate regulation, inventory would have been $5,486,000 higher [2005 - $4,767,000].

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

6. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2006			2005		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Land rights	**10,229**	**2,022**	**8,207**	10,074	1,819	8,255
Computer software	**118,861**	**86,070**	**32,791**	97,590	72,840	24,750
Leasehold improvements	**693**	**215**	**478**	1,239	383	856
Capital contributions	**2,043**	**197**	**1,846**	2,043	116	1,927
Software in development	**5,944**	**—**	**5,944**	6,138	—	6,138
	137,770	**88,504**	**49,266**	117,084	75,158	41,926

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2006 $	2005 $
Regulatory assets recovery account	**37,510**	55,408
Excess of cash pension contributions	**—**	4,785
Excess of OEB annual cost	**—**	3,559
Smart meters	**29,018**	—
	66,528	63,752

Regulatory liabilities consist of the following:

	2006 $	2005 $
Pre-market opening line loss variance	**2,880**	2,880
Settlement variances	**7,990**	10,417
Other	**970**	—
	11,840	13,297

For the year ended December 31, 2006, LDC recovered approved regulatory assets amounts of $26,877,000 through permitted distribution rate adjustments [2005 - $24,563,000]. These recovery amounts are for the recovery of approved regulatory assets recorded in reporting periods prior to January 1, 2005. In accordance with the OEB's direction, the Corporation recorded carrying charges on the recovered amounts of $nil in 2006 [2005 - $1,544,000].

In the absence of rate regulation, interest income for the year ended December 31, 2006 would have been $nil [2005 - higher by $1,544,000].

For the years ended December 31, 2006 and December 31, 2005, recovery amounts were credited directly to reduce the regulatory assets recovery account. The regulatory assets and liabilities balances of the Corporation are defined as follows:

[a] Regulatory assets recovery account

On March 31, 2005, the OEB ordered that the approved regulatory asset balances be aggregated into a single regulatory account. Approved regulatory assets of $71,465,000 consisted of transition costs of $37,868,000, pre-market opening energy electricity variance of $26,129,000, and settlement variances of $31,852,000, less recoveries of $24,384,000, which were transferred to the "regulatory asset recovery account" ["RARA"]. This approved balance will be recovered over a period ending March 31, 2008. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges. In the absence of rate regulation, interest income in 2006 would have been $1,685,000 lower [2005 - $2,539,000].

The transition costs and pre-market opening energy electricity variance are defined as follows:

[i] Transition costs

The OEB allowed the LDC to defer the costs incurred to align systems and practices with the requirements of the competitive electricity market in Ontario in accordance with the *Ontario Energy Board Act, 1998*. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook.

Under such regulation, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2003 to March 31, 2005, transition costs were increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $558,000 lower.

[ii] Pre-market opening energy electricity variance

The OEB has allowed the LDC to recognize the pre-market opening energy electricity variance for the period January 1, 2001 to April 30, 2002, the date of market opening. The pre-market opening energy variance represented the difference between the LDC's cost of power purchased based upon time-of-use ["TOU"] rates and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2001 to March 31, 2005, the pre-market opening energy electricity variance was increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $370,000 lower.

[b] Excess of cash pension contributions

The OEB has allowed the LDC to defer the incremental OMERS pension expenditures for the fiscal years starting after January 1, 2005 and to end on April 30, 2006. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $6,510,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $1,725,000 higher [2005 - $4,785,000].

[c] Excess of OEB annual cost

The OEB has allowed the LDC to defer a portion of the OEB annual cost assessments for the fiscal years starting after January 1, 2004 and to end on April 30, 2006. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $4,345,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $786,000 higher [2005 - $2,166,000].

[d] Smart Meters

Effective May 1, 2006, the OEB has allowed the LDC to defer capital expenditures, operating expenditures, depreciation expense and revenues relating to smart meters. Accordingly, the Corporation has deferred these items in accordance with the criteria set out in the AP Handbook.

Under such regulation, in 2006, smart meter capital expenditures of $30,347,000 [2005 - $nil] were deferred. These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment in 2006 would have been $30,347,000 higher [2005 - $nil].

In 2006, smart meter operating expenditures of $526,000 [2005 - $nil] were deferred which would be expensed under Canadian GAAP for unregulated businesses., and smart meter depreciation expense of $690,000 [2005 - $nil] was deferred which otherwise would be charged to depreciation expense under Canadian GAAP for unregulated businesses. In the absence of rate regulation, operating expenses and depreciation expense in 2006 would have been $526,000 and $690,000 higher respectively [2005 - $nil and $nil respectively].

In 2006, smart meter customer revenues of $2,966,000 [2005 - $nil] were deferred. In the absence of rate regulation, revenue in 2006 would have been $2,966,000 higher [2005 - $nil].

The deferred balances continue to be calculated and attract carrying charges. In 2006, the Corporation recorded carrying charges of $422,000 [2005 - $nil] on the deferred amounts. In the absence of rate regulation, interest income in 2006 would have been $422,000 lower [2005 - $nil].

The manner and timing of disposition of these smart meter regulatory assets have not been determined by the OEB at this time.

[e] Pre-market opening line loss variance

The OEB has allowed the LDC to defer the pre-market opening line loss variance for the period June 1, 2001 to April 30, 2002. This balance represents the variance between amounts charged by LDC to customers for the OEB-approved loss adjustment factor and the LDC actual loss adjustment factor. Accordingly, the Corporation has deferred this variance in accordance with the OEB's direction.

In the absence of rate regulation, there would have been no impact on the Consolidated Statement of Income for 2006 and 2005. The deferred balance does not attract carrying charges. The manner and timing of disposition of the variance have not been determined by the OEB.

[f] Settlement variances

The OEB has allowed the LDC to defer settlement variances from May 1, 2002 to December 31, 2006. This balance represents the variances between amounts charged by LDC to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by LDC after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

Settlement variances of $27,980,000, relating to the period from May 1, 2002 to December 31, 2004, were approved for recovery by the OEB and are included in the RARA balance. The remaining balance, representing settlement variances arising after January 1, 2005, is deferred in a regulatory liability account.

In the absence of rate regulation, interest income in 2006 would have been $49,000 lower [2005 - $1,112,000]. The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance have not been determined by the OEB.

8. OTHER ASSETS

Other assets consist of the following:

	2006 $	2005 $
Deferred debt issue costs, net of accumulated amortization of $1,412,000 [2005 - $1,025,000]	**2,457**	2,843
Long-term advances and deposits	**—**	1,566
Other	**121**	1,081
	2,578	5,490

9. BANK INDEBTEDNESS AND BANKERS' ACCEPTANCES

On May 5, 2005, the Corporation extended its revolving credit facility with a syndicate of Canadian banks [the "Revolving Credit Facility"] for a three-year period to May 4, 2008. Under the terms of the revolving credit facility, the Corporation may borrow up to $500,000,000, of which:

[a] $500,000,000 less the amount utilized under [b] is available for working capital purposes in the form of prime rate loans in Canadian dollars and bankers' acceptances; and

[b] up to $175,000,000 is available in the form of letters of credit to support the prudential requirements of LDC and TH Energy and general credit requirements of the Corporation and its subsidiaries.

The facility contains a negative pledge, customary covenants and events of default.

At December 31, 2006, $81,620,000 [December 31, 2005 - $90,174,000] had been utilized under the revolving credit facility in the form of letters of credit to support the prudential requirements of LDC [$80,000,000] [2005 - $80,000,000], TH Energy [$780,000] [2005 - $9,194,000] and Telecom [$840,000] [2005 - $980,000]. At December 31, 2006, no amounts had been drawn for working capital purposes [December 31, 2005 - $nil].

The Corporation also has a bilateral demand line of credit for $20,000,000 with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate [December 31, 2006 – 6%]. At December 31, 2006, no amounts had been drawn on the line of credit [December 31, 2005 - $nil].

10. CURRENT PORTION OF OTHER LONG-TERM LIABILITIES

Current portion of other long-term liabilities consist of the following:

	2006 $	2005 $
Current portion of obligations under capital leases *[note 20]*	**733**	1,877
Customers' advance deposits	**15,904**	37,029
Other	**315**	304
	16,952	39,210

11. LONG-TERM DEBT

Long-term debt consists of the following:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

	2006 $	2005 $
Senior unsecured debentures	**225,000**	225,000
Promissory note payable to the City	**980,231**	980,231
	1,205,231	1,205,231
Less: Current portion of promissory note payable to the City	**245,058**	330,000
Long-term debt	**960,173**	875,231
Comprising:		
Debentures	**225,000**	225,000
Promissory note payable to the City	**735,173**	650,231

All debt of the Corporation ranks equally.

a) Senior unsecured debentures

On May 7, 2003, the Corporation issued $225,000,000 10-year senior unsecured debentures. The Corporation's 10-year senior unsecured debentures in the amount of $225,000,000, as at December 31, 2006, [December 31, 2005 - $225,000,000] bear interest at a rate of 6.11% per annum, payable semi-annually in arrears in equal instalments on May 7 and November 7 of each year. The debentures mature on May 7, 2013.

The Corporation may redeem some or all of the debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to but excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any price. The debentures have the benefit of certain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

b) Promissory note payable to the City of Toronto

LDC issued a promissory note to the City on July 1, 1999 ["Initial Note"] in the principal amount of $947,000,000 in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. Pursuant to the Transfer By-law, the principal amount of the Initial Note was adjusted effective January 1, 2000 to $980,231,000 to reflect the deemed debt to equity structure of LDC [65:35] permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note ["Replacement Note"] issued by LDC, which was interest bearing at the rate of 6.8% per annum. At December 31, 2002, the Replacement Note was payable on the earlier of demand and December 31, 2003.

Concurrent with the closing of the debenture offering on May 7, 2003, the City transferred the Replacement Note to the Corporation in consideration for the issue by the Corporation to the City of a new promissory note in the

principal amount of $980,231,000 [2005 – $980,231,000] [the "City Note"]. At December 31, 2005 the principal amount of the City Note, together with accrued interest thereon, was payable:

[a] on demand on not less than 90 days written notice until May 7, 2006; and

[b] in accordance with a payment schedule to be delivered by the City at least 90 days before May 7, 2006;

provided that the Corporation will not be required to pay more than $330,000,000 of the principal amount of the City Note during any twelve-month period. Accordingly, $330,000,000 of the principal amount outstanding under the City Note was classified as a current liability. In 2005 the maximum term of the City Note was ten years.

On September 5, 2006, the Corporation announced that it and the City had amended and restated the City Note effective May 1, 2006 by fixing the interest rate at 6.11% and establishing an agreed repayment schedule. The Corporation is required to pay the principal amount of the note as follows: $245,058,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and on May 6, 2013. Accordingly, $245,058,000 of the principal amount outstanding under the City Note is classified as a short-term liability, with the remainder being classified as a long-term liability. Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year.

12. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2006, the Corporation's OMERS current service pension costs were $10,343,000 [2005 - $8,965,000].

Employee future benefits other than pension

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits [excluding pension] to most of its employees. The Corporation pays certain medical and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The Corporation measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2005. The December 31, 2006 year-end accrued benefit obligation reflects a December 31, 2006 discount rate. This result was achieved by updating the January 1, 2005 actuarial valuation using the December 31, 2006 discount rate of 5.3% while keeping all other assumptions constant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

[a] Accrued benefit obligation

	2006 $	2005 $
Balance at beginning of year	**167,013**	139,468
Experience gain at beginning of year	—	(1,446)
Current service cost	**3,907**	3,152
Interest cost	**8,412**	8,178
Benefits paid	**(5,372)**	(4,988)
Actuarial (gains) losses	**(6,499)**	22,649
Balance at end of year	**167,461**	167,013

[b] Reconciliation of the accrued benefit obligation to the balance sheet accrued benefits liability

	2006 $	2005 $
Accrued benefit obligation	**167,461**	167,013
Unamortized net actuarial loss	**(26,593)**	(34,427)
Unamortized past service costs	**(6,186)**	(7,171)
Post-employment benefits liability	**134,682**	125,415

[c] Components for net periodic defined benefit costs

	2006 $	2005 $
Current service cost	**3,907**	3,152
Interest cost	**8,412**	8,178
Actuarial (gains) losses	**(6,499)**	21,203
Cost incurred in the year	**5,820**	32,533
Differences between costs incurred and costs recognized in the year in respect of:		
Actuarial loss (gain)	**7,789**	(21,230)
Past service costs	**985**	983
	8,774	(20,247)
Defined benefit costs recognized	**14,594**	12,286
Capitalized as part of property, plant and equipment	**6,385**	3,672
Charged to operations	**8,209**	8,614

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

[d[Significant assumptions

	2006 %	2005 %
Accrued benefit obligation as of December 31:		
Discount rate	**5.3**	5.0
Rate of compensation increase	**4.0**	4.0
Benefit costs for years ended December 31:		
Discount rate	**5.0**	5.9
Rate of compensation increase	**4.0**	4.0
Assumed health care cost trend rates at December 31:		
Rate of increase in dental costs	**4.5**	4.5

For December 31, 2006 and 2005, medical costs are assumed to increase at 10.5% graded down by 1.0% annual decrements to 4.5% in 2011 and thereafter.

[e] Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates have the following effects for 2006:

	Increase $	Decrease $
Net periodic benefit cost (at 5.0%)	**2,282**	**(1,699)**
Accrued benefit obligation at December 31, 2006 (at 5.3%)	**27,682**	**(21,182)**

13. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following:

	2006 $	2005 $
Obligations under capital leases *[note 20]*	**1,033**	2,063
Security deposits	**1,575**	3,277
Lease liability – long-term	**—**	285
Other	**1,341**	3,452
	3,949	9,077

During 2006, the Corporation acquired "Property, plant and equipment" through capital lease transactions totaling $556,000 [2005 - $43,000]. These non-cash transactions have been excluded from the Consolidated Statement of Cash Flows.

14. ASSET RETIREMENT OBLIGATIONS

A reconciliation between the opening and closing ARO liability balances is as follows:

	2006 $	2005 $
Balance, beginning of year	**5,691**	4,274
ARO liabilities incurred in the year	**2,039**	1,525
ARO liabilities settled in the year	**(509)**	(351)
Accretion expense	**360**	243
Balance, end of year	**7,581**	5,691

At December 31, 2006, the Corporation estimates the undiscounted amount of cash flows required over the next ten years to settle the ARO is $11,372,000 [2005 - $6,836,000]. Discount rates ranging from 4.3% to 6.0% were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

15. FINANCIAL INSTRUMENTS

Electricity retailing commitments

In December 2002, TH Energy ceased new electricity retailing activities in respect of new customers as a result of the price freeze implemented under Bill 210. TH Energy managed the remaining portfolio of electricity contracts comprised primarily of fixed notional volume contracts, wholesale financial fixed notional volume fixed-for-floating and floating-for-fixed swaps and fixed notional volume physical bilateral contracts. The contracts are derivative contracts for accounting purposes. The electricity contracts had varying maturity dates throughout the period ending December 31, 2006.

At December 31, 2006, TH Energy had floating-for-fixed electricity contracts that had an aggregate expected contract volume and value of nil MWh and $nil [2005 – 3,124,000 MWh and $171,270,000].

To hedge the volume and price risk inherent in retailing electricity, TH Energy entered into financial fixed notional volume fixed-for-floating swaps and fixed notional physical bilateral contracts with generators and marketers. At December 31, 2006, the aggregate notional volume and value of these contracts were nil MWh and $nil [2005 – 3,614,000 MWh and $154,396,000].

For the year ended December 31, 2006, "Revenues" include $20,661,000 of electricity mark-to-market revenues [2005 - $34,309,000].

Credit risk

Financial instruments result in exposure to credit risk stemming from the risk of the counter-party defaulting on its obligations. TH Energy monitors and limits its exposure to counter-parties with lower credit ratings and evaluates its counter-party credit exposure on a continuous basis. TH Energy obtains collateral from some counter-parties and seeks to deal only with counter-parties with investment-grade credit ratings. TH Energy had five wholesale counter-parties as at December 31, 2006 for its electricity supply portfolio. In addition, TH Energy provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties. The largest single credit exposure at December 31, 2006 is estimated at $12,382,389, which is the December 2006 invoice of power sold to one counter party [2005 - $137,170,000].

For retail customers, credit losses are generally low across the sector. LDC, TH Energy and Telecom provide for an allowance for doubtful accounts to absorb credit losses. At December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets other than the risk mentioned above.

Interest rate risk

The Corporation is exposed to interest rate risk for certain of its financial assets and liabilities. Under the Corporation's Revolving Credit Facility *[note 9]*, the Corporation may have short-term borrowings for working capital purposes. These borrowings would expose the Corporation to fluctuations in short-term interest rates [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Corporation's credit rating.

Certain cash balances of the Corporation is invested in Canadian money market instruments, with terms of one day to 90 days, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Fair value of financial instruments

The carrying value of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximates their fair value due to the immediate or short-term maturity of these financial instruments**.**

At December 31, 2006, the fair values of the City Note [$980,231,000] and the senior unsecured debentures [$225,000,000] are $1,034,640,000 and $247,515,000 [2005 - $1,120,405,000 and $251,415,000]. These fair values have been calculated by discounting the future cash flow of the respective long-term debt at the estimated yield to maturity of similar debt instruments *[note 11]*.

The fair value of hedging derivative financial instruments is the estimated amount the Corporation would receive (pay) to terminate the contracts. The value is based on market prices or management's best estimates if there is no organized market and/or if the market is illiquid.

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December 31, 2006

All retail fixed notional volume fixed price contracts and all undesignated wholesale fixed notional volume fixed-for-floating swaps and fixed notional volume physical bilateral contracts are accounted for using the mark-to-market method of accounting. The following are the primary sources of the change in the net mark-to-market assets:

	2006 $	2005 $
Net mark-to-market assets		
Fair value, beginning of year	**26,422**	27,696
Unrealized change in fair value during the period	**(4,431)**	16,342
Realization of contracts for the period	**(21,991)**	(17,616)
Fair value of net mark-to-market assets, end of year	**—**	26,422

16. FINANCIAL GUARANTEES

Participants [including LDC and TH Energy] in the wholesale market for electricity are required to satisfy prescribed prudential requirements. In addition, counter-parties under contracts for the purchase and sale of electricity and customers under purchase contracts may require parental financial guarantees or other forms of credit support.

The City has authorized the Corporation to provide up to $500,000,000 in financial support [including guarantees] with respect to prudential requirements and as security for obligations under third party contracts.

At December 31, 2006, the Corporation's board of directors had approved $386,000,000 in parental guarantees on behalf of TH Energy, of which $56,500,000 has been issued to unrelated parties [2005 - $86,500,000].

The Corporation has issued a parental guarantee to the City as part of an agreement to purchase electricity at a fixed price from TH Energy. The fair value of the parental guarantee was $nil at December 31, 2006 [2005 - $56,417,000]

17. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. Reconciliation between the statutory and effective tax rates is set out below:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Consolidated Statement of income

	2006 $	2005 $
Rate reconciliation		
Income before PILs	**148,622**	159,756
Consolidated Statutory Canadian federal and provincial income tax rate	**36.12%**	36.12%
Expected provision for PILs	**53,682**	57,704
Increase in income taxes resulting from large corporations tax net of surtax	**—**	1,655
Temporary differences not benefited	**3,482**	10,630
Valuation allowance	**1,150**	(2,056)
Decrease in federal future tax rates	**2,215**	—
Other	**(2,126)**	906
Provision for PILs	**58,403**	68,839
Effective tax rate	**39.30%**	43.09%
Components of provision for PILs		
Current tax provision	**60,890**	71,960
Future income tax recovery related to the origination and reversal of temporary differences	**(2,487)**	(3,121)
Provision for PILs	**58,403**	68,839

Consolidated Balance sheet

Significant components of the Corporation's future income tax assets and liabilities are as follows:

	2006 $	2005 $
Non-capital loss carryforwards	**576**	2,785
Property, plant and equipment and intangible assets	**27,968**	32,153
Other taxable temporary differences	**4,735**	(4,998)
Valuation allowance	**(16,847)**	(15,973)
	16,432	13,967

Presented on the consolidated balance sheet as follows:

	2006 $	2005 $
Future income tax assets, current	**791**	33,195
Future income tax assets, long-term	**16,009**	22,264
Future income tax liabilities, current	**—**	(40,923)
Future income tax liabilities, long-term	**(368)**	(569)
	16,432	13,967

Under the taxes payable method applicable to LDC, no adjustments are made for differences between the financial statement carrying values and the tax basis of assets and liabilities. As at December 31, 2006, future income tax assets of $234,217,000 [2005 - $249,838,000], based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Corporation's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs in 2006 would have been $3,482,000 lower [2005 – $7,863,000 lower][*note 4 [b]*].

As at December 31, 2006, the Corporation has accumulated tax losses for PILs purposes of approximately $1,744,000, which are available to reduce future years' taxable income. These loss carryforwards begin to expire in 2008.

As at December 31, 2006, LDC has accumulated a PILs variance amount, representing the difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs, totaling an under-recovery of $10,286,000 [2005 -$4,948,000]. LDC has also accumulated a PILs variance amount representing differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application totalling an over-recovery of $1,702,000 [2005 - $ nil]. Cumulative interest included in the amounts was calculated following OEB direction and totaled $3,004,000 [2005 - $2,858,000].

18. SHARE CAPITAL

Share capital consists of the following:

	2006 $	2005 $
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares		
Issued and outstanding		
1,000 common shares	**567,817**	567,817

Dividends

The shareholder direction adopted by the City with respect to the Corporation provided that the Corporation's board of directors would use its best efforts to ensure that the Corporation met certain financial performance standards, including those relating to credit rating and dividends. Subject to applicable law, the shareholder direction provided that the Corporation would pay dividends to the City each year.

Subject to applicable law and the shareholder direction, the amount of the annual dividends payable by the Corporation to the City is to be the greater of $25,000,000 or 50% of the Corporation's annual consolidated net income. The dividends are not cumulative and are payable as follows:

[a] $6,000,000 on the last day of each of the first three fiscal quarters in each year;

[b] $7,000,000 on the last day of the fiscal year; and

[c] the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25,000,000 within ten days after the board of directors of the Corporation approves the Corporation's audited consolidated financial statements for the year.

During 2006, the board of directors of the Corporation declared and paid dividends totaling $46,200,000 to the City [2005 - $68,000,000].

19. RELATED PARTIES

For the Corporation, transactions with related parties include transactions with the City. All transactions with the City are conducted at prevailing market prices and normal trade terms.

For the year ended December 31, 2006, LDC provided street lighting electricity to the City in the amount of $9,281,000 [2005 - $11,089,000].

For the year ended December 31, 2006, TH Energy invoiced the City for electricity for $102,771,000 [2005 - $107,450,000]. At December 31, 2006, included in "Accounts receivable, net of allowance for doubtful accounts" are $5,905,000 [2005 - $1,257,000] receivable from the City related to these electricity billing activities.

For the year ended December 31, 2006, TH Energy provided energy efficiency products and services to the City amounting to $2,010,000 [2005 - $1,927,000].

On December 31, 2005, TH Energy acquired the street lighting and expressway lighting assets from the City for cash consideration of $60,000,000. The transaction was recorded at the exchange amount, which is reflective of the fair market value, as an increase in property, plant and equipment. The acquisition of these assets was recorded at the exchange amount since the carrying value of the assets in the City's records was not determinable. The purchase price was supported by an independent valuation of the fair market value of the acquired assets. The acquired assets are being depreciated over their estimated remaining service lives.

Concurrently with the transaction, the Corporation entered into a service agreement with the City to provide street lighting and expressway lighting services to the City for a period of 30 years commencing January 1, 2006. During

2006, TH Energy provided street and expressway lighting services to the City totalling $15,287,000 [2005 - $4,712,000].

For the year ended December 31, 2006, LDC incurred property taxes payable to the City of $7,306,000 [2005 - $7,030,000].

At December 31, 2006, a promissory note in the amount of $980,231,000 [2005 - $980,231,000] was payable to the City. For the year ended December 31, 2006, interest expense of $59,892,000 [2005 - $66,656,000], on the promissory note was paid to the City *[note 11]*.

20. LEASE COMMITMENTS

Operating lease obligations

As at December 31, 2006, the future minimum annual lease payments under property and computer hardware operating leases with remaining lease terms from one to five years are as follows:

	$
2007	**4,646**
2008	**5,793**
2009	**5,567**
2010	**5,498**
2011	**5,018**
Thereafter	**2,953**
Total minimum lease payments	**29,475**

Capital lease obligations

As at December 31, 2006, the future minimum annual lease payments under vehicle capital leases with remaining lease terms from one to five years are as follows:

	$
2007	**733**
2008	**562**
2009	**552**
2010	**160**
Thereafter	**11**
Total amount of future minimum lease payments	**2,018**
Less interest	**252**
	1,766
Current portion *[note 10]*	**733**
Long-term portion *[note 13]*	**1,033**

21. CONTINGENCIES

a) Ministry of Finance Tax Audit

The Ministry of Finance is currently carrying out a tax audit on the Corporation and its subsidiaries. Certain filing positions for PILs taken by the Corporation and its subsidiaries may be challenged on the audit. This may result in a material increase in the Corporation's reported tax obligations upon reassessment. As the audit has not yet been completed, management is not able to determine the impact, if any, of the audit on the consolidated financial statements or the Corporation's tax reserves. The Corporation adjusts its tax reserves when there is sufficient information available, or when an event occurs requiring a change to the reserves.

b) Consumers' Gas Decision

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada [the "Supreme Court"] ruled that The Consumers' Gas Company ["Consumers' Gas"] was required to repay the portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the *Criminal Code* in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement, however, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff, and to receive lawyer's fees in connection with that effort. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario municipal electric utilities under the Class Proceedings Act, 1992 seeking $500,000,000 in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the Class Proceedings Act, 1992 seeking $64,000,000 in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is also at the preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the *Criminal Code* is fact specific in each circumstance. Accordingly, given the preliminary status of these actions, it is not possible at this time to quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

22. NET INCOME PER SHARE

The weighted daily average numbers of shares outstanding were 1,000 as at December 31, 2006 and 2005, for purposes of determining basic and fully diluted net income per share for continuing and discontinued operations. Basic and fully diluted net income per share for continuing and discontinued operations were determined by dividing the net income for the year by the weighted daily average number of shares outstanding.

23. DISCONTINUED OPERATIONS

In November 2006, the Board of Directors of TH Energy approved a plan to sell the water heater assets and to exit this business segment. Accordingly, the results of operations and financial position of the water heater business have been segregated and presented as discontinued operations in the accompanying financial statements. As at December 31, 2006, the net assets of the water heater business have been measured and presented at the lower of the carrying amount or fair value less cost to sell. The net assets held for sale are as follows:

	$
Current assets held for sale:	
Property, plant and equipment	**12,098**
	12,098
Current liabilities held for sale:	
Accounts payable	**103**
Future income tax liabilities	**803**
	906

For the year ended December 31, 2006 and 2005, the following revenue and expenses of the water heater business have been reclassified from continuing operations to discontinued operations:

	2006 $	2005 $
Sales	**8,085**	8,147
Expenses		
Purchased power and other	**1,820**	1,753
Operating expenses	**879**	319
Depreciation and amortization	**2,405**	3,498
	5,104	5,570
Provision of payments in lieu of corporate taxes	**803**	1,049
Income from discontinued operations	**2,178**	1,528

24. SEGMENT REPORTING

The designation of the segments has been based on a combination of the regulatory status and the nature of products and services provided. The Corporation has two reportable segments:

[a] Electricity Distribution:
the regulated business which consists of the electricity distribution business of LDC; and

[b] Non-regulated:
the non-regulated business of TH Energy which consist primarily of the delivery of street lighting and expressway lighting services, the sale of energy management services, and up until December 31, 2006, the management of a portfolio of electricity contracts. The non-regulated business of Telecom which consists of the provision of fibre optic capacity and data communications services to telecommunications carriers, business customers and large institutions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Segment information on the above basis is as follows:

	2006 $	2005 $
Electricity Distribution		
Revenues	**2,264,469**	2,709,819
Purchased power and other	**1,784,144**	2,224,034
Depreciation and amortization	**124,560**	124,988
Interest income	**11,225**	10,485
Interest expense	**76,537**	80,620
Segment profit before interest, other items and provision for payments in lieu of corporate taxes	**186,701**	193,658
Payment in lieu of corporate taxes	**46,001**	61,114
Non-regulated		
Revenues	**75,530**	103,434
Purchased power and other	**14,654**	42,331
Depreciation and amortization	**12,784**	6,607
Interest income	**84,520**	81,865
Interest expense	**80,278**	80,717
Segment profit before interest, other items and provision for payments in lieu of corporate taxes	**22,902**	30,045
Payment in lieu of corporate taxes	**12,402**	7,725
Intersegment eliminations		
Revenues	**(92,991)**	(206,981)
Purchased power and other	**(92,953)**	(206,576)
Interest income	**(78,019)**	(78,234)
Interest expense	**(78,019)**	(78,234)

	2006 $	2005 $
Total		
Revenues	**2,247,008**	2,606,272
Purchased power and other	**1,705,845**	2,059,789
Depreciation and amortization	**137,344**	131,595
Interest income	**17,726**	14,116
Interest expense	**78,796**	83,103
Income before interest, other items and provision for payments in lieu of corporate taxes	**209,603**	223,703
Payment in lieu of corporate taxes	**58,403**	68,839

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

	2006 $	2005 $
Expenditures on property, plant and equipment and intangible assets		
Electricity Distribution	**167,685**	132,260
Non-regulated	**22,934**	68,095
Intersegment eliminations	**(5,312)**	—
Total	**185,307**	200,355

	2006 $	2005 $
Assets		
Electricity Distribution	**2,280,811**	2,393,533
Non-regulated	**1,505,987**	1,619,790
Intersegment eliminations	**(1,207,190)**	(1,194,065)
Discontinued operations	**12,098**	—
Total	**2,591,706**	2,819,258

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. COMPARATIVE CONSOLIDATED FINANCIAL STATEMENTS

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the 2006 consolidated financial statements.

26. SUBSEQUENT EVENTS

Regulatory Affairs

On January 26, 2007, LDC filed an Annual Rate Adjustment Application for 2007 Rates as directed to by the OEB. In accordance with the OEB's Incentive Regulation Model, LDC has sought authorization to increase its rates by 0.4% on May 1, 2007.

Sale of water heater business

On February 8, 2007, TH Energy sold its water heater business to Consumers' Waterheater Income Fund for cash consideration of $40,800,000 subject to post closing adjustments and transaction costs. This transaction will be recorded in the financial statements in 2007.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Dividends

On March 1, 2007, the board of directors of the Corporation declared a dividend in the amount of $27,199,000. The dividends are comprised of a $21,199,000 payment for 2006 net income, payable to the City on March 9, 2007 and a $6,000,000 payment in connection with the first quarter of 2007, payable to the City on March 30, 2007.

AUDITED FINANCIAL STATEMENTS

THESL's audited financial statements for the year ended December 31, 2006 including note disclosures and comparative balances for the year ended December 31, 2005 are included in Appendix A of this Exhibit.

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2006

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2006

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AUDITORS' REPORT

To the Shareholder of
Toronto Hydro-Electric System Limited

We have audited the balance sheet of **Toronto Hydro-Electric System Limited** ["LDC"] as at December 31, 2006 and the statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of LDC's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of LDC as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Toronto, Canada,
February 21, 2007 [except as to note 22, which is
which is as of February 22, 2007].

Chartered Accountants

Toronto Hydro-Electric System Limited

BALANCE SHEET

[in thousands of dollars]

As at December 31	**2006** $	2005 $
ASSETS		
Current		
Cash and cash equivalents	**157,391**	310,760
Accounts receivable, net of allowance for doubtful accounts	**191,841**	142,451
Unbilled revenue	**226,297**	281,775
Inventories	**22,458**	18,189
Prepaid expenses	**970**	158
Total current assets	**598,957**	753,333
Property, plant and equipment, net *[note 5]*	**1,566,718**	1,532,053
Intangible assets, net *[note 6]*	**46,658**	40,266
Regulatory assets *[note 7]*	**66,528**	63,752
Other assets *[note 8]*	**1,950**	4,129
Total assets	**2,280,811**	2,393,533
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**242,894**	374,638
Current portion of other liabilities *[note 9]*	**16,637**	38,906
Deferred revenue	**4,647**	19,637
Current portion of promissory note payable to related party *[notes 10 and 18]*	**245,058**	980,231
Total current liabilities	**509,236**	1,413,412
Long-term liabilities		
Long-term note payable to related party *[notes 10 and 18]*	**180,000**	180,000
Long-term promissory note payable to related party *[notes 10 and 18]*	**735,173**	-
Post-employment benefits *[note 11]*	**122,344**	114,576
Regulatory liabilities *[note 7]*	**11,840**	13,297
Other liabilities *[note 12]*	**2,611**	7,127
Asset retirement obligations *[note 13]*	**7,581**	5,691
Customers' advance deposits	**25,944**	2,900
Total long-term liabilities	**1,085,493**	323,591
Total liabilities	**1,594,729**	1,737,003
Commitments and contingencies *[notes 19 and 20]*		
Shareholder's equity		
Share capital *[note 17]*	**527,817**	527,817
Retained earnings	**145,508**	117,322
Contributed surplus	**12,757**	11,391
Total shareholder's equity	**686,082**	656,530
Total liabilities and shareholder's equity	**2,280,811**	2,393,533

Toronto Hydro-Electric System Limited

STATEMENT OF INCOME

[in thousands of dollars]

Year ended December 31	**2006**	2005
	$	**$**
Revenues		
Sale of electricity	**2,242,993**	2,686,751
Other income	**21,476**	23,068
	2,264,469	2,709,819
Costs		
Purchased power	**1,784,144**	2,224,034
Operating expenses	**169,064**	167,139
Depreciation and amortization	**124,560**	124,988
	2,077,768	2,516,161
Income before interest, other and provision for payments in lieu of corporate taxes	**186,701**	193,658
Interest income	**11,225**	10,485
Interest expense		
Long-term notes	**(74,024)**	(78,533)
Other interest	**(2,513)**	(2,087)
Other	**598**	2,965
Income before provision for payments in lieu of corporate taxes	**121,987**	126,488
Provision for payments in lieu of corporate taxes *[note 16]*	**46,001**	61,114
Net income	**75,986**	65,374

STATEMENT OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31	**2006**	2005
	$	**$**
Retained earnings, beginning of year	**117,322**	166,474
Net income	**75,986**	65,374
Dividends *[note 17]*	**(47,800)**	(114,526)
Retained earnings, end of year	**145,508**	117,322

Toronto Hydro-Electric System Limited

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	**2006**	2005
	$	$
OPERATING ACTIVITIES		
Net income	**75,986**	65,374
Adjustments for non-cash items		
Depreciation and amortization	**124,560**	124,988
Net change in other assets and liabilities	**4,771**	8,714
Gains on disposals of property, plant and equipment	**(598)**	(2,965)
Changes in non-cash working capital balances		
Decrease (increase) in accounts receivable	**(49,390)**	798
Decrease (increase) in unbilled revenue	**55,478**	(48,505)
Decrease (increase) in inventories	**(4,269)**	1,184
Increase in prepaid expenses	**(812)**	(77)
Increase (decrease) in accounts payable and accrued liabilities	**(131,744)**	96,452
Increase (decrease) in deferred revenue	**(14,990)**	19,637
Increase (decrease) in current portion of other liabilities	**(34)**	1,219
Net cash provided by operating activities	**58,958**	266,819
INVESTING ACTIVITIES		
Purchase of property, plant and equipment	**(150,952)**	(124,236)
Purchase of intangible assets	**(16,733)**	(8,024)
Net change in regulatory assets and liabilities	**(4,233)**	20,548
Proceeds on disposal of property, plant and equipment	**6,738**	3,001
Net cash used in investing activities	**(165,180)**	(108,711)
FINANCING ACTIVITIES		
Increase (decrease) in customers' advance deposits	**1,835**	(20,081)
Repayment of capital lease liability	**(1,182)**	(1,866)
Dividends paid *[note 17]*	**(47,800)**	(114,526)
Net cash used in financing activities	**(47,147)**	(136,473)
Net increase (decrease) in cash and cash equivalents during the year	**(153,369)**	21,635
Cash and cash equivalents, beginning of year	**310,760**	289,125
Cash and cash equivalents, end of year	**157,391**	310,760
Supplementary cash flow information		
Total interest paid	**75,166**	79,483
Payments in lieu of corporate taxes	**87,401**	51,837

NOTES TO FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2006

1. INCORPORATION

On June 23, 1999, Toronto Hydro-Electric System Limited [“LDC”] was incorporated under the Business Corporations Act (Ontario). LDC is a wholly-owned subsidiary of Toronto Hydro Corporation Inc. [“the Corporation”]. The incorporation was required in accordance with the provincial government's Electricity Act, 1998.

Under the terms of By-law No. 374-1999 of the City of Toronto made under section 145 of the Electricity Act, 1998 and in accordance with continuity of interest accounting, the former Toronto Hydro-Electric Commission and the City of Toronto [the “City”] transferred, at book value, their assets and liabilities [effective July 1, 1999] and employees [effective January 1, 2000] associated with electricity distribution to LDC in consideration for the issuance of equity securities of LDC and long-term notes payable to the City.

The equity securities of LDC were subsequently transferred by the City to the Corporation in consideration for the issuance of equity securities of the Corporation to the City.

The book value of the assets transferred at July 1, 1999 was $1,548,048,000.

LDC distributes electricity to customers located in the City and it is subject to rate regulation.

2. REGULATION

In April 1999, the government of Ontario initiated a restructuring of Ontario’s electricity industry. The restructuring was intended, among other things, to facilitate competition in the generation and sale of electricity, to protect the interests of consumers with respect to prices and the reliability and quality of electricity service and to promote economic efficiency in the generation, transmission and distribution of electricity.

The Ontario Energy Board [the “OEB”] has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB’s authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

[i] *Electricity Price and Related Rebates*. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

[ii] *Distribution Rate*. The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge.* The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

3. ELECTRICITY DISTRIBUTION RATES

In connection with the restructuring of Ontario's electricity industry in 1999, the OEB authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return of 9.88% on the deemed debt to equity structure of LDC of 65:35. The adjustment was being phased in over three adjustment periods to lessen the impact on customers. Effective on each of December 1, 2000 and March 1, 2002, the OEB authorized LDC to increase its distribution rates to allow for the recovery of additional annual revenue of $39.8 million.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39.8 million, representing the third and final adjustments necessary to achieve a market-based rate of return of 9.88%. The rate increase was effective as of April 1, 2005 and subjected LDC to a financial commitment to invest $39.8 million in Conservation and Demand Management ["CDM"] activities by September 2007.

In April 2006, the OEB approved a decrease in the distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $57,956,000, including the new regulatory treatment for revenues relating to smart meters *[see note 7]*. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on deemed equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980,231,000 promissory note between LDC and the Corporation from 6.8% to 5% per annum.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates and other permitted recoveries.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of LDC have been prepared in accordance with Canadian generally accepted accounting principles [“GAAP”], including accounting principles prescribed by the OEB in the handbook “Accounting Procedures Handbook for Electric Distribution Utilities” [“AP Handbook”] and reflect the significant accounting policies summarized below.

a) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian Institute of Chartered Accountants [“CICA”] Accounting Guideline 19 “Disclosures by Entities Subject to Rate Regulation” [“AcG-19”], certain costs and variance account balances deemed to be “regulatory assets” or “regulatory liabilities” are reflected separately on LDC’s balance sheet until the manner and timing of disposition is determined by the OEB *[note 7]*.

Payments in lieu of corporate taxes

LDC is exempt from tax under the *Income Tax Act (Canada)* [“ITA”] and the *Corporations Tax Act (Ontario)*, if not less than 90% of its capital is owned by the Corporation, a “municipal electricity utility” [“MEU”], and not more than 10% of its income is derived from activities carried on outside the municipal geographical boundaries of the City.

LDC is a MEU for purposes of the payments in lieu of corporate taxes [“PILs”] regime contained in the Electricity Act, 1998. The Electricity Act, 1998 provides that a MEU that is exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* is required to make, for each taxation year, a PILs, to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

The PILs regime came into effect on October 1, 2001, at which time LDC was deemed to have commenced a new taxation year for purposes of determining the respective liabilities for PILs. Accordingly, LDC was deemed to have disposed of its assets at their then fair market value and to have re-acquired such assets at the same amount. The differences between the financial statement carrying value and tax basis of assets and liabilities were accounted for by LDC under the taxes payable method of accounting applied in accordance with recommendations of the CICA and the OEB.

Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time.

The OEB's Electricity Distribution Rate Handbooks, issued in March 2000 and May 2005, provides for the recovery of PILs by LDC through annual distribution rate adjustments as permitted by the OEB. The OEB-approved distribution rate for PILs recoveries is based on estimated consumption volumes. The difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs amount up to April 30, 2006, is tracked by LDC as a variance amount in accordance with OEB guidelines for regulatory assets and with criteria set out in the AP Handbook. Commencing May 1, 2006, any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application are tracked by LDC as variance amounts.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property, plant and equipment of LDC. According to the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Spare transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the AP Handbook, spare transformers are treated as capital assets *[note 5]* which would be recorded as inventory under Canadian GAAP for unregulated businesses.

b) Cash and cash equivalents

Effective January 1, 2006, LDC changed the terms to maturity in the definition of cash equivalents from five months or less to 90 days or less from the date of acquisition. This change resulted in no impact on the audited financial statements as at December 31, 2006 and 2005.

c) Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on an average cost basis net of the provision for obsolescence.

d) Property, plant and equipment and depreciation

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to "Other" in the Statement of Income.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

Buildings	1.7% to 10.0%
Stations	2.9% to 5.0%
Distribution lines	2.5% to 4.0%
Transformers	3.3% to 4.0%
Meters	2.9% to 4.0%
Other capital assets	6.7% to 12.5%
Communications	10% to 20.0%
Computer hardware	20.0% to 25.0%
Rolling stock	12.5% to 33.3%
Equipment and tools	10.0%

Construction in progress includes assets not currently in use which are not depreciated.

e) Intangible assets

Intangible assets, which lack physical substance, are stated at cost. Amortization is provided on a straight-line basis over their estimated useful service lives at the following annual rates:

Land rights	2.0%
Computer software	14.0% to 33.0%
Capital contributions	4.0%

Software in development includes assets not currently in use which are not amortized.

f) Deferred debt issue costs

In 2003, LDC incurred debt issue costs arising from the issuance of long-term notes payable to the Corporation, with the funds raised through the Corporation's debenture offering *[note 8]*. Deferred debt issue costs are included in "Other assets" and represent the unamortized amounts of debt costs arising from the issuance of debt, and other related costs. Deferred debt issue costs are amortized over the period to maturity of the debt on a straight-line basis.

g) Workplace Safety and Insurance Act

LDC is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act ["WSIA"]. As a Schedule 1 employer, LDC is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

h) Revenue recognition

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39,800,000. The rate increase was effective as of April 1, 2005 and is subject to a financial commitment by LDC to spend $39,800,000 in CDM activities by September 2007. The revenue of $39,800,000 was billed to customers over a period of 11-months commencing April 1, 2005. At each reporting date, on a life-to-date basis, to the extent the earned customer revenue exceeds the CDM activity spending, the difference is recorded on the balance sheet as “Deferred revenue”.

Other income, which includes revenues from electricity distribution related services, is recognized as the services are performed.

i) Employee future benefits

Pension plan

LDC provides a pension plan for its full-time employees through Ontario Municipal Employees Retirement System [“OMERS”]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees’ contributory earnings. LDC recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension

Employee future benefits other than pension provided by LDC include medical and life insurance benefits, accumulated sick leave credits and voluntary exit incentive program liability. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains (losses) over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in the period in which a settlement occurs.

j) Customers' advance deposits

Customers' advance deposits are cash collections from customers to guarantee the payment of energy bills. The customers' advance deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

k) Asset retirement obligations

LDC recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in distribution equipment and in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligations ["ARO"] is incurred and when the fair value is determined.

Effective June 30, 2006, LDC adopted Emerging Issues Committee Abstract EIC-159 "Conditional Asset Retirement Obligations" ["EIC-159"]. EIC-159 requires an entity to recognize a liability for the fair value of an ARO even though the timing or method of settlement is conditional on future events. LDC has identified conditional AROs and recognized the related liability in 2006. The adoption has been accounted for prospectively as information is not available to allow it to be accounted for retroactively. The fair value of the identified AROs and the change from prior period are determined to be not material to the LDC's result of operations and financial position.

l) Use of estimates

The preparation of LDC's financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

NOTES TO FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

5. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2006			2005		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**4,088**	**—**	**4,088**	4,136	—	4,136
Buildings	**140,803**	**44,009**	**96,794**	144,048	43,332	100,716
Stations	**191,833**	**99,988**	**91,845**	183,155	94,179	88,976
Distribution lines	**2,005,432**	**1,017,605**	**987,827**	1,922,918	942,109	980,809
Transformers	**493,878**	**264,308**	**229,570**	471,562	247,102	224,460
Meters	**131,886**	**80,032**	**51,854**	127,468	75,721	51,747
Other capital assets	**43,506**	**29,829**	**13,677**	33,665	28,554	5,111
Communications	**23,327**	**20,801**	**2,526**	21,345	19,680	1,665
Computer hardware	**39,266**	**35,037**	**4,229**	36,578	33,436	3,142
Rolling stock	**57,237**	**44,243**	**12,994**	51,439	40,990	10,449
Equipment and tools	**33,168**	**23,488**	**9,680**	28,086	22,232	5,854
Construction in progress	**61,634**	**—**	**61,634**	54,988	—	54,988
	3,226,058	**1,659,340**	**1,566,718**	3,079,388	1,547,335	1,532,053

At December 31, 2006, spare transformers with carrying amounts of $5,486,000 [2005 - $4,767,000], are included in "Property, plant and equipment, net" *[note 4[a] "Spare transformers"]*. In the absence of rate regulation, inventory would have been $5,486,000 higher [2005 - $4,767,000].

6. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2006			2005		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Land rights	**10,101**	**2,013**	**8,088**	9,946	1,813	8,133
Computer software	**107,849**	**77,034**	**30,815**	91,731	67,663	24,068
Capital contributions	**2,043**	**197**	**1,846**	2,043	116	1,927
Software in development	**5,909**	**—**	**5,909**	6,138	—	6,138
	125,902	**79,244**	**46,658**	109,858	69,592	40,266

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2006 $	2005 $
Regulatory assets recovery account	**37,510**	55,408
Excess of cash pension contributions	**—**	4,785
Excess of OEB annual cost	**—**	3,559
Smart meters	**29,018**	—
	66,528	63,752

Regulatory liabilities consist of the following:

	2006 $	2005 $
Pre-market opening line loss variance	**2,880**	2,880
Settlement variances	**7,990**	10,417
Other	**970**	—
	11,840	13,297

For the year ended December 31, 2006, LDC recovered approved regulatory assets amounts of $26,877,000 through permitted distribution rate adjustments [2005 – $24,563,000]. These recovery amounts are for the recovery of approved regulatory assets recorded in reporting periods prior to January 1, 2005. In accordance with the OEB's direction, LDC recorded carrying charges on the recovered amounts of $nil in 2006 [2005 - $1,544,000]. In the absence of rate regulation, interest income for the year ended December 31, 2006 would have been $nil [2005 - higher by $1,544,000].

For the years ended December 31, 2006 and December 31, 2005, recovery amounts were credited directly to reduce the regulatory assets recovery account. The regulatory assets and liabilities balances of LDC are defined as follows:

[a] Regulatory assets recovery account

On March 31, 2005, the OEB ordered that the approved regulatory asset balances be aggregated into a single regulatory account. Approved regulatory assets of $71,465,000 consisted of transition costs of $37,868,000, pre-market opening energy electricity variance of $26,129,000, and settlement variances of $31,852,000, less recoveries of $24,384,000, which were transferred to the "regulatory asset recovery account" ["RARA"]. This approved balance will be recovered over a period ending March 31, 2008. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges. In the absence of rate regulation, interest income in 2006 would have been $1,685,000 lower [2005 - $2,539,000].

The transition costs and pre-market opening energy electricity variance are defined as follows:

[i] Transition costs

The OEB allowed LDC to defer the costs incurred to align systems and practices with the requirements of the competitive electricity market in Ontario in accordance with the *Ontario Energy Board Act, 1998*. Accordingly, LDC has deferred these expenditures in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook.

Under such regulation, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2003 to March 31, 2005, transition costs were increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $558,000 lower.

[ii] Pre-market opening energy electricity variance

The OEB has allowed LDC to recognize the pre-market opening energy electricity variance for the period January 1, 2001 to April 30, 2002, the date of market opening. The pre-market opening energy variance represented the difference between LDC's cost of power purchased based upon time-of-use ["TOU"] rates and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period. Accordingly, LDC has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2001 to March 31, 2005, the pre-market opening energy electricity variance was increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $370,000 lower.

[b] Excess of cash pension contributions

The OEB has allowed LDC to defer the incremental OMERS pension expenditures for the fiscal years starting after January 1, 2005 and to end on April 30, 2006. Accordingly, LDC has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $6,510,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $1,725,000 higher [2005 - $4,785,000].

[c] Excess of OEB annual cost

The OEB has allowed LDC to defer a portion of the OEB annual cost assessments for the fiscal years starting after January 1, 2004 and to end on April 30, 2006. Accordingly, LDC has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $4,345,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $786,000 higher [2005 - $2,166,000].

[d] Smart Meters

Effective May 1, 2006, the OEB has allowed LDC to defer capital expenditures, operating expenditures, and revenues relating to smart meters. Accordingly, LDC has deferred these items in accordance with the criteria set out in the AP Handbook.

Under such regulation, in 2006, smart meter capital expenditures of $30,347,000 [2005 - $nil] were deferred. These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated business. In the absence of rate regulation, property, plant and equipment in 2006 would have been $30,347,000 higher [2005 - $nil].

In 2006, smart meter operating expenses of $526,000 [2005 - $nil] were deferred which would be expensed under Canadian GAAP for unregulated businesses, and smart meter depreciation expense of $690,000 [2005 - $nil] was deferred which otherwise would have been charged to depreciation expense under Canadian GAAP for unregulated businesses. In the absence of rate regulation, operating expenses and depreciation expense in 2006 would have been $526,000 and $690,000 higher respectively [2005 - $nil and $nil respectively].

In 2006, smart meter customer revenues of $2,966,000 [2005 - $nil] were deferred. In the absence of rate regulation, revenue in 2006 would have been $2,966,000 higher [2005 - $nil].

The deferred balances continued to be calculated and attract carrying charges. In 2006, LDC recorded carrying charges of $422,000 [2005 - $nil] on the deferred amounts. In the absence of rate regulation, interest income in 2006 would have been $422,000 lower [2005 - $nil].

The manner and timing of disposition of these smart meter regulatory assets have not been determined by the OEB at this time.

[e] Pre-market opening line loss variance

The OEB has allowed LDC to defer the pre-market opening line loss variance for the period June 1, 2001 to April 30, 2002. This balance represents the variance between amounts charged by LDC to customers for the OEB-approved loss adjustment factor and LDC actual loss adjustment factor. Accordingly, LDC has deferred this variance in accordance with the OEB's direction.

In the absence of rate regulation, there would have been no impact on the Statement of Income for 2006 and 2005. The deferred balance does not attract carrying charges. The manner and timing of disposition of the variance have not been determined by the OEB.

[f] Settlement variances

The OEB has allowed LDC to defer settlement variances from May 1, 2002 to December 31, 2006. This balance represents the variances between amounts charged by LDC to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by LDC after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, LDC has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

Settlement variances of $27,980,000 relating to the period from May 1, 2002 to December 31, 2004, were approved for recovery by the OEB and are included in the RARA balance. The remaining balance, representing settlement variances arising after January 1, 2005, is deferred in a regulatory liability account.

In the absence of rate regulation, interest income in 2006 would have been $49,000 lower [2005 - $1,112,000]. The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance have not been determined by the OEB.

8. OTHER ASSETS

Other assets consist of the following:

	2006 $	2005 $
Deferred debt issue costs, net of accumulated amortization of $1,091,000 [2005 - $792,000]	**1,898**	2,197
Long-term advances and deposits	**—**	1,566
Other	**52**	366
	1,950	4,129

9. CURRENT PORTION OF OTHER LONG-TERM LIABILITIES

Current portion of other long-term liabilities consist of the following:

	2006 $	2005 $
Current portion of obligations under capital leases *[note 19]*	**733**	1,877
Customers' advance deposits	**15,904**	37,029
	16,637	38,906

10. LONG-TERM DEBT

Long-term debt consists of the following:

	2006 $	2005 $
Long-term note payable to the Corporation	**180,000**	180,000
Promissory note payable to the Corporation	**980,231**	980,231
	1,160,231	1,160,231
Less: Current portion of promissory note payable to the Corporation	**245,058**	980,231
Long-term debt	**915,173**	180,000
Comprising:		
Long-term note payable to the Corporation	**180,000**	180,000
Promissory note payable to the Corporation	**735,173**	—

All debt of the Corporation ranks equally.

a) Long-term note payable to the Corporation

The long-term note payable to the Corporation bears interest at a rate of 6.16% per annum, with a maturity date of May 6, 2013, extendable upon mutual consent.

b) Promissory note payable to the Corporation

On July 1, 1999, LDC issued a promissory note to the City [“Initial Note”] in the principal amount of $947,000,000 in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. As authorized under the Transfer By-law, to reflect regulatory changes made by the OEB, the principal amount of the Initial Note was adjusted effective January 1, 2000 to $980,231,000 to reflect the deemed debt/common equity structure of LDC [65:35] permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note [“Replacement Note”] issued by LDC, which was interest bearing at the rate of 6.8% per annum. At December 31, 2002, the Replacement Note was payable on the earlier of demand and December 31, 2003.

Concurrent with the closing of the Corporation’s debenture offering on May 7, 2003, the City transferred the Replacement Note to the Corporation in consideration for the issuance by the Corporation to the City of a new promissory note in the principal amount of $980,231,000. Following the issuance of the new promissory note to the City, on May 7, 2003, LDC issued a promissory note payable on demand to the Corporation in the principal amount of $980,231,000.

On September 5, 2006, LDC amended and restated the promissory note payable to the Corporation effective May 1, 2006 by fixing the interest rate at 6.16% and establishing an agreed repayment schedule. LDC is required to pay the principal amount of the note as follows: $245,058,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and on May 6, 2013. Accordingly, $245,058,000 of the principal amount outstanding under the promissory note is classified as a short-term liability, with the remainder being classed as a long-term liability. Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year.

11. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2006, LDC's OMERS current service pension costs were $7,812,000 [2005-$6,674,000].

Employee future benefits other than pension

LDC has a number of unfunded benefit plans providing retirement and post-employment benefits [excluding pension] to most of its employees. LDC pays certain medical and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. LDC pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

LDC measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2005. The December 31, 2006 year-end accrued benefit obligation reflects a December 31, 2006 discount rate. This result was achieved by updating the January 1, 2005 actuarial valuation using the December 31, 2006 discount rate of 5.3% while keeping all other assumptions constant.

[a] Accrued benefit obligation

	2006 $	2005 $
Balance at beginning of year	**154,543**	128,303
Experience loss at beginning of year	**—**	423
Current service cost	**3,316**	2,694
Interest cost	**7,760**	7,603
Benefits paid	**(5,329)**	(4,948)
Actuarial (gains) losses	**(5,824)**	20,468
Balance at end of year	**154,466**	154,543

NOTES TO FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2006

[b] Reconciliation of the accrued benefit obligation to the balance sheet accrued benefits liability

	2006 $	2005 $
Accrued benefit obligation	**154,466**	154,543
Unamortized net actuarial loss	**(27,431)**	(34,527)
Unamortized past service costs	**(4,691)**	(5,440)
Post-employment benefits liability	**122,344**	114,576

[c] Components for net periodic defined benefit costs

	2006 $	2005 $
Current service cost	**3,316**	2,694
Interest cost	**7,760**	7,603
Actuarial (gains) losses	**(5,824)**	20,891
Cost incurred in the year	**5,252**	31,188
Differences between costs incurred and costs recognized in the year in respect of:		
Actuarial loss (gain)	**7,096**	(20,806)
Past service costs	**745**	745
	7,841	(20,061)
Defined benefit costs recognized	**13,093**	11,127
Capitalized as part of property, plant and equipment	**6,385**	3,672
Charged to operations	**6,708**	7,455

[d] Significant assumptions

	2006 %	2005 %
Accrued benefit obligation as of December 31:		
Discount rate	**5.3**	5.0
Rate of compensation increase	**4.0**	4.0
Benefit costs for years ended December 31:		
Discount rate	**5.0**	5.9
Rate of compensation increase	**4.0**	4.0
Assumed health care cost trend rates at **December 31:**		
Rate of increase in dental costs	**4.5**	4.5

For December 31, 2006 and 2005, medical costs are assumed to increase at 10.5% graded down by 1.0% annual decrements to 4.5% in 2011 and thereafter.

[e] Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates have the following effects for 2006:

	Increase $	Decrease $
Net periodic benefit cost (at 5.0%)	**1,943**	**(1,456)**
Accrued benefit obligation at December 31, 2006 (at 5.3%)	**24,738**	**(18,983)**

12. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following:

	2006 $	2005 $
Obligations under capital leases *[note 19]*	**1,033**	2,063
Security deposits	**1,575**	3,277
Other	**3**	1,787
	2,611	7,127

During 2006, LDC acquired "Property, plant and equipment" through capital lease transactions totaling $556,000 [2005 - $43,000]. These non-cash transactions have been excluded from the statement of cash flows.

13. ASSET RETIREMENT OBLIGATIONS

A reconciliation between the opening and closing ARO liability balances is provided below:

	2006 $	2005 $
Balance, beginning of year	**5,691**	4,274
ARO liabilities incurred in the year	**2,039**	1,525
ARO liabilities settled in the year	**(509)**	(351)
Accretion expense	**360**	243
Balance, end of year	**7,581**	5,691

At December 31, 2006, LDC estimates the undiscounted amount of cash flows required over the next ten years to settle the ARO is $11,372,000 [December 31, 2005 - $6,836,000]. Discount rates ranging from 4.3% to 6.0% were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

14. FINANCIAL INSTRUMENTS

Credit risk

Financial assets expose LDC to credit risk. Credit risk is the loss from non-performance by suppliers, customers or financial counter-parties. At December 31, 2006, there are no significant concentrations of credit risk with respect to any class of financial assets.

Fair value of financial instruments

The carrying value of cash and cash equivalents, accounts receivable, loan receivable from related party, accounts payable and accrued liabilities approximates their fair value due to the immediate or short-term maturity of these financial instruments.

At December 31, 2006, the fair value of the long-term note payable to the Corporation *[note 10]* is $197,145,000 [2005 - $200,173,000], which has been calculated by discounting the future cash flow of the long-term note payable at the estimated yield to maturity of a similar debt instrument.

At December 31, 2006, the fair value of the promissory note payable to the Corporation *[note 10]* is $1,036,000,000, which has been calculated by discounting the future cash flow of the promissory note payable at the estimated yield to maturity of a similar debt instrument.

15. FINANCIAL GUARANTEES

Participants in the wholesale market for electricity are required to satisfy prescribed prudential requirements. In addition, counter-parties under contracts for the purchase and sale of electricity and customers under purchase contracts may require parental financial guarantees or other forms of credit support.

The City has authorized the Corporation to provide up to $500,000,000 in financial support [including guarantees] with respect to prudential requirements and as security for obligations under third party contracts. At December 31, 2006, no parental guarantees have been issued on behalf of LDC [2005 - $nil].

At December 31, 2006, $80,000,000 [2005 - $80,000,000] was utilized under the Corporation's revolving credit facility in the form of letters of credit to support the prudential requirements of LDC.

16. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. Reconciliation between the statutory and effective tax rates is provided as follows:

Statement of income

	2006 $	2005 $
Rate reconciliation		
Income before PILs	**121,987**	126,488
Statutory Canadian federal and provincial income tax rate	**36.12%**	36.12%
Expected taxes on income	**44,062**	45,688
Increase in income taxes resulting from large corporations tax net of surtax	**—**	1,468
Temporary differences not benefited	**3,482**	11,158
Other	**(1,543)**	2,800
Provision for PILs	**46,001**	61,114
Effective tax rate	**37.71%**	48.32%
Components of provision for PILs		
Current tax provision	**46,001**	61,114
Provision for PILs	**46,001**	61,114

Balance sheet

Future income taxes relating to LDC have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax assets of $234,217,000 [2005 - $249,838,000], based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, LDC's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs in 2006 would have been $3,482,000 lower [2005 – $7,863,000 lower].

As at December 31, 2006, LDC has accumulated a PILs variance amount, representing the difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs, totaling an under-recovery of $10,286,000 [2005 - $4,948,000]. LDC has also accumulated a PILs variance amount representing differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application totalling an over-recovery of $1,702,000 [2005 - $ nil]. Cumulative interest included in the amounts was calculated following OEB direction and totaled $3,004,000 [2005 - $2,858,000].

17. SHARE CAPITAL

Share capital consists of the following:

	2006 $	2005 $
Authorized The authorized share capital of LDC consists of an unlimited number of common shares. Any invitation to the public to subscribe for securities is prohibited.		
Issued and outstanding 1,000 common shares	**527,817**	527,817

Dividends

During 2006, the board of directors of LDC declared and paid dividends totaling $47,800,000 to the Corporation [2005 - $114,526,000].

18. RELATED PARTIES

For LDC, transactions with related parties include transactions with Toronto Hydro Energy Services Inc., ["TH Energy"], Toronto Hydro Telecom Inc., ["Telecom"], the Corporation and the City.

Included in "Accounts receivable, net of allowance for doubtful accounts" are amounts due from related parties as follows:

	2006 $	2005 $
Due from Telecom	**310**	—
Due from TH Energy	**—**	315
	310	315

Included in "Accounts payable and accrued liabilities" are amounts due to related parties as follows:

	2006 $	2005 $
Due to the Corporation	**12,692**	9,334
Due to Telecom	**—**	2,388
Due to TH Energy	**73**	—
	12,765	11,722

NOTES TO FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2006

At December 31, 2006, the long-term note of $180,000,000 was payable to the Corporation [2005 – $180,000,000]. For the year ended December 31, 2006, interest expense was paid to the Corporation in the amount of $11,088,000 [2005 – $11,088,000] *[note 10]*.

At December 31, 2006, the promissory note of $980,231,000 was payable to the Corporation [2005 – $980,231,000]. For the year ended December 31, 2006, interest expense was paid to the Corporation in the amount of $62,637,000 [2005 – $67,146,000] *[note 10]*.

On December 31, 2006, LDC sold the land and building located at 10 Belfield Road, Toronto to TH Energy, for cash consideration of $5,800,000 representing the approximate market value of the property as determined by an accredited appraiser. For accounting purposes, the reduction in property plant and equipment balance was recorded at the net book value of $4,324,000 with the remaining balance of $1,366,000 [$1,476,000 gross, net of current tax payable of $110,000] representing the difference between the assets' net book value and the consideration received recorded to "contributed surplus".

For the year ended December 31, 2006, LDC provided electricity to the City in the amounts of $9,281,000 [2005 - $11,089,000].

For the year ended December 31, 2006, LDC earned electricity revenues of $90,663,000 [2005 - $204,248,000] from TH Energy. At December 31, 2006, included in "Unbilled revenue" is $19,745,000 [2005 - $21,793,000] of unbilled revenue due from TH Energy related to electricity revenues.

During 2006, LDC provided services to the Corporation in the amounts of $3,081,000 in the ordinary course of business and measured at their exchange amounts [2005 - $1,974,000].

During 2006, LDC provided material and services to TH Energy totaling $7,416,000 [2005 - $6,463,000] in the ordinary course of business at prevailing market prices and normal trade terms.

For the year ended December 31, 2006, LDC provided services to Telecom amounting to $2,541,000 [2005 - $2,485,000] at prevailing market prices and normal trade terms.

For the year ended December 31, 2006, LDC incurred property taxes payable to the City of $7,306,000 [2005 - $7,030,000].

During 2006, LDC purchased corporate and management services from the Corporation totaling $51,447,000 [2005 - $52,275,000] in the ordinary course of business, with these services charged to operating expenses and measured at their exchange amounts.

During 2006, LDC purchased electricity of $nil [2005 - $403,000] from TH Energy.

19. LEASE COMMITMENTS

Operating lease obligations

As at December 31, 2006, the future minimum annual lease payments under property and computer hardware operating leases with remaining lease terms from one to five years are as follows:

	$
2007	**3,194**
2008	**4,290**
2009	**4,061**
2010	**3,988**
2011	**3,503**
Thereafter	**828**
Total minimum lease payments	**19,864**

Capital lease obligations

As at December 31, 2006, the future minimum annual lease payments under vehicle capital leases with remaining lease terms from one to five years are as follows:

	$
2007	**733**
2008	**562**
2009	**552**
2010	**160**
Thereafter	**11**
Total amount of future minimum lease payments	**2,018**
Less interest	**252**
	1,766
Current portion *[note 9]*	**733**
Long-term portion *[note 12]*	**1,033**

20. CONTINGENCIES

Ministry of Finance Tax Audit

The Ministry of Finance is currently carrying out a tax audit on LDC. Certain filing positions for PILs taken by LDC may be challenged on the audit. This may result in a material increase in LDC's reported tax obligations upon reassessment. As the audit has not yet been completed, management is not able to determine the impact, if any, of the audit on the financial statements or LDC's tax reserves. LDC adjusts its tax reserves when there is sufficient information available, or when an event occurs requiring a change to the reserves.

Consumers' Gas Decision

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada [the "Supreme Court"] ruled that Consumers' Gas Company ["Consumers' Gas"] was required to repay the portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the *Criminal Code* in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement, however, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff, and to receive lawyer's fees in connection with that effort. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario municipal electric utilities under the Class Proceedings Act, 1992 seeking $500,000,000 in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code.* This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the Class Proceedings Act, 1992 seeking $64,000,000 in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is also at the preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the *Criminal Code* is fact specific in each circumstance. Accordingly, given the preliminary status of these actions, it is not possible at this time to quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

21. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2006 financial statements.

22. SUBSEQUENT EVENTS

Regulatory Affairs

On January 26, 2007, LDC filed an Annual Rate Adjustment Application for 2007 Rates as directed to by the OEB. In accordance with the OEB's Incentive Regulation Model, LDC has sought authorization to increase its rates by 0.4% on May 1, 2007.

Dividends

On February 22, 2007, the board of directors of LDC declared dividends in the amount of $6,000,000. The dividend is payable on March 30, 2007.

AUDITED FINANCIAL STATEMENTS

THC's audited financial statements for the year ended December 31, 2006 including note disclosures and comparative balances for the year ended December 31, 2005 are included in Appendix A of this Exhibit.

Consolidated Financial Statements

Toronto Hydro Corporation

December 31, 2006

Consolidated Financial Statements

Toronto Hydro Corporation

December 31, 2006

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AUDITORS' REPORT

To the Shareholder of
Toronto Hydro Corporation

We have audited the consolidated balance sheets of **Toronto Hydro Corporation** [the "Corporation"] as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst + Young LLP

Toronto, Canada,
February 21, 2007 [except as to note 26,
which is as of March 1, 2007].

Chartered Accountants

Toronto Hydro Corporation

CONSOLIDATED BALANCE SHEET

[in thousands of dollars]

As at December 31	2006 $	2005 $
ASSETS		
Current		
Cash and cash equivalents	**327,524**	448,370
Accounts receivable, net of allowance for doubtful accounts	**218,452**	174,499
Unbilled revenue	**216,857**	271,367
Inventories	**22,458**	18,189
Prepaid expenses	**2,277**	2,168
Electricity mark-to-market assets *[note 15]*	**-**	113,297
Future income tax assets *[note 17]*	**791**	33,195
Assets from discontinued operations *[note 23]*	**12,098**	-
Total current assets	**800,457**	1,061,085
Property, plant and equipment, net *[note 5]*	**1,656,868**	1,624,741
Intangible assets, net *[note 6]*	**49,266**	41,926
Regulatory assets *[note 7]*	**66,528**	63,752
Other assets *[note 8]*	**2,578**	5,490
Future income tax assets *[note 17]*	**16,009**	22,264
Total assets	**2,591,706**	2,819,258
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**284,869**	423,780
Current portion of other liabilities *[note 10]*	**16,952**	39,210
Current portion of deferred revenue	**7,320**	20,423
Current portion of promissory note payable *[note 11]*	**245,058**	330,000
Electricity mark-to-market liabilities *[note 15]*	**-**	86,875
Future income tax liabilities *[note 17]*	**-**	40,923
Liabilities from discontinued operations *[note 23]*	**906**	-
Total current liabilities	**555,105**	941,211
Long-term liabilities		
Debentures *[note 11]*	**225,000**	225,000
Promissory note payable *[note 11]*	**735,173**	650,231
Post-employment benefits *[note 12]*	**134,682**	125,415
Regulatory liabilities *[note 7]*	**11,840**	13,297
Other liabilities *[note 13]*	**3,949**	9,077
Asset retirement obligations *[note 14]*	**7,581**	5,691
Customers' advance deposits	**25,944**	2,900
Future income tax liabilities *[note 17]*	**368**	569
Total long-term liabilities	**1,144,537**	1,032,180
Total liabilities	**1,699,642**	1,973,391
Commitments and contingencies *[notes 20 and 21]*		
Shareholder's equity		
Share capital *[note 18]*	**567,817**	567,817
Retained earnings	**324,247**	278,050
Total shareholder's equity	**892,064**	845,867
Total liabilities and shareholder's equity	**2,591,706**	2,819,258

ON BEHALF OF THE BOARD:

Clare R. Copeland, Director

L. Ross Cullingworth, Director

Toronto Hydro Corporation

CONSOLIDATED STATEMENT OF INCOME

[in thousands of dollars, except for per share amounts]

Year ended December 31	**2006** **$**	**2005** **$**
Revenues	**2,247,008**	2,606,272
Costs		
Purchased power and other	**1,705,845**	2,059,789
Operating expenses	**194,216**	191,185
Depreciation and amortization	**137,344**	131,595
	2,037,405	2,382,569
Income before interest, other and provision for payments in lieu of corporate taxes	**209,603**	223,703
Interest income	**17,726**	14,116
Interest expense		
Long-term debt	**(75,894)**	(80,403)
Other interest	**(2,902)**	(2,700)
Other	**89**	5,040
Income before provision for payments in lieu of corporate taxes	**148,622**	159,756
Provision for payments in lieu of corporate taxes *[note 17]*	**58,403**	68,839
Income from continuing operations	**90,219**	90,917
Income from discontinued operations - net of tax *[note 23]*	**2,178**	1,528
Net income	**92,397**	92,445
Basic and fully diluted net income per share from continuing operations *[note 22]*	90,219	90,917
Basic and fully diluted net income per share from discontinued operations *[note 22]*	2,178	1,528
Basic and fully diluted net income per share	**92,397**	92,445

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31	**2006** **$**	**2005** **$**
Retained earnings, beginning of year	**278,050**	253,605
Net income	**92,397**	92,445
Dividends *[note 18]*	**(46,200)**	(68,000)
Retained earnings, end of year	**324,247**	278,050

Toronto Hydro Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	**2006** **$**	**2005** $
OPERATING ACTIVITIES		
Income from continuing operations	**90,219**	90,917
Adjustments for non-cash items		
Depreciation and amortization	**137,344**	131,595
Net change in other assets and liabilities	**(3,191)**	1,878
Electricity mark-to-market assets and liabilities	**26,422**	1,274
Post-employment benefits	**9,267**	7,298
Future income taxes	**(2,488)**	(3,121)
Gain on disposals of property, plant and equipment	**(89)**	(5,040)
Changes in non-cash working capital balances		
Decrease (increase) in accounts receivable	**(44,003)**	9,080
Decrease (increase) in unbilled revenue	**54,510**	(25,245)
Decrease (increase) in inventories	**(4,269)**	1,719
Decrease (increase) in prepaid expenses	**(60)**	45
Increase (decrease) in accounts payable and accrued liabilities	**(137,787)**	93,045
Increase (decrease) in deferred revenue	**(13,179)**	20,423
Increase in current portion of other liabilities	**32**	1,219
Net cash provided by operating activities	**112,728**	325,087
INVESTING ACTIVITIES		
Purchase of property, plant and equipment	**(166,806)**	(192,241)
Purchase of intangible assets	**(18,501)**	(8,114)
Net change in regulatory assets and liabilities	**(4,233)**	20,548
Proceeds on disposal of property, plant and equipment	**938**	5,085
Net cash used in investing activities	**(188,602)**	(174,722)
FINANCING ACTIVITIES		
Increase (decrease) in customers' advance deposits	**1,835**	(20,081)
Repayment of capital lease liability	**(1,182)**	(1,866)
Dividends paid *[note 18]*	**(46,200)**	(68,000)
Net cash used in financing activities	**(45,547)**	(89,947)
Net cash provided by (used in) continuing operations	**(121,421)**	60,418
Net cash provided by discontinued operations	**575**	1,327
Net increase (decrease) in cash and cash equivalents during the year	**(120,846)**	61,745
Cash and cash equivalents, beginning of year	**448,370**	386,625
Cash and cash equivalents, end of year	**327,524**	448,370
Supplementary cash flow information		
Total interest paid	77,442	81,657
Payments in lieu of corporate income taxes	106,771	74,780

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2006

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the Business Corporations Act (Ontario) along with two wholly-owned subsidiary companies, Toronto Hydro-Electric System Limited ["LDC"] and Toronto Hydro Energy Services Inc. ["TH Energy"]. The incorporation was required in accordance with the provincial government's Electricity Act, 1998.

Under the terms of By-law No. 374-1999 of the City of Toronto ["Transfer By-law"] made under section 145 of the Electricity Act, 1998 and in accordance with continuity of interest accounting, the former Toronto Hydro-Electric Commission and the City of Toronto [the "City"] transferred, at book value, their assets and liabilities [effective July 1, 1999] and employees [effective January 1, 2000] associated with:

[a] electricity distribution to LDC in consideration for the issuance of equity securities of LDC and long-term notes payable to the City; and

[b] electricity generation, co-generation and energy services to TH Energy in consideration for the issuance of equity securities of TH Energy.

The equity securities of LDC and TH Energy were subsequently transferred by the City to the Corporation in consideration for the issuance of equity securities of the Corporation to the City.

Certain surplus real property assets and cash funds were excluded from the transfer and were retained by the City. In addition, the long-term debt incurred by the City on behalf of the former Toronto Hydro-Electric Commission was excluded from the liabilities transferred and was retained by the City.

The book value of the assets transferred at July 1, 1999 was $1,548,048,000. The principal amount of the long-term notes payable to the City was $980,231,000 and the value of the common shares of the Corporation received by the City was $567,817,000.

The Corporation supervises the operations of, and provides corporate and management services and strategic direction to, its subsidiary companies [each of which is listed below, incorporated under the BCA and wholly-owned, directly or indirectly, by the Corporation]:

[a] LDC [incorporated June 23, 1999] – which distributes electricity to customers located in the City and is subjected to rate regulation.

[b] TH Energy [incorporated June 23, 1999] – which owns and operates street lighting and expressway lighting systems located in the City and is engaged in the sale of energy efficiency products and services.

[c] Toronto Hydro Telecom Inc. ["Telecom"] [incorporated September 26, 2000] – which provides fibre optic cable capacity and manages data communications services.

[d] 1455948 Ontario Inc. [incorporated December 21, 2000] – which owns a 50% interest in EBT Express Partnership ["EBT Express"], a joint venture with a wholly-owned subsidiary of Ontario Power Generation Inc. EBT Express owns a 67% controlling interest in The SPi Group, a corporation formed to provide, among other things, centralized electronic data management and transaction services to energy industry participants.

The principal business of the Corporation is the regulated distribution of electricity by LDC.

2. REGULATION

In April 1999, the government of Ontario initiated a restructuring of Ontario's electricity industry. The restructuring was intended, among other things, to facilitate competition in the generation and sale of electricity, to protect the interests of consumers with respect to prices and the reliability and quality of electricity service and to promote economic efficiency in the generation, transmission and distribution of electricity.

The Ontario Energy Board [the "OEB"] has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

[i] *Electricity Price and Related Rebates*. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

[ii] *Distribution Rate*. The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge*. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

3. ELECTRICITY DISTRIBUTION RATES

In connection with the restructuring of Ontario's electricity industry in 1999, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return of 9.88% on the deemed debt to equity structure of LDC of 65:35. The adjustment was being phased in over three adjustment periods to lessen the rate impact on customers. Effective on each of December 1, 2000 and March 1, 2002, the OEB authorized LDC to increase its distribution rates to allow for the recovery of additional annual revenue of $39.8 million.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39.8 million, representing the third and final adjustments necessary to achieve a market-based rate of return of 9.88%. The rate increase was effective as of April 1, 2005 and subjected the LDC to a financial commitment to invest $39.8 million in Conservation and Demand Management ["CDM"] activities by September 2007.

In April 2006, the OEB approved a decrease in the distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $57,956,000, including the new regulatory treatment for revenues relating to smart meters [see *note 7*]. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on deemed equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980,231,000 promissory note between LDC and the Corporation from 6.8% to 5% per annum.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates and other permitted recoveries.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Corporation have been prepared in accordance with Canadian generally accepted accounting principles ["GAAP"], including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ["AP Handbook"] and reflect the significant accounting policies summarized below.

a) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian Institute of Chartered Accountants [“CICA”] Accounting Guideline 19 “Disclosures by Entities Subject to Rate Regulation” [“AcG-19”], certain costs and variance account balances deemed to be “regulatory assets” or “regulatory liabilities” are reflected separately on LDC’s balance sheet until the manner and timing of disposition is determined by the OEB *[note 7]*.

Payments in lieu of corporate taxes

The Corporation and its subsidiaries are exempt from tax under the *Income Tax Act (Canada)* [“ITA”] and the *Corporations Tax Act (Ontario)*, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income and each of its subsidiaries is derived from activities carried on outside the municipal geographical boundaries of the City.

The Corporation and each of its subsidiaries is a “municipal electricity utility” [“MEU”] for purposes of the payments in lieu of corporate taxes [“PILs”] regime contained in the Electricity Act, 1998. The Electricity Act, 1998 provides that a MEU that is exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* is required to make, for each taxation year, a PILs, to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining the respective liabilities for PILs. Accordingly, the Corporation and its subsidiaries were deemed to have disposed of their assets at their then fair market value and to have re-acquired such assets at the same amount. The differences between the financial statement carrying value and tax basis of assets and liabilities were accounted for by the Corporation as follows:

[a] in the case of the Corporation's unregulated businesses, the liability method of accounting was applied in accordance with recommendations of the CICA; and

[b] in the case of the Corporation’s regulated electricity distribution business, the taxes payable method of accounting was applied in accordance with recommendations of the CICA and the OEB.

Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arise from temporary differences in the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time.

The OEB's Electricity Distribution Rate Handbooks, issued in March 2000 and May 2005, provide for the recovery of PILs by LDC through annual distribution rate adjustments as permitted by the OEB. The OEB-approved distribution rate for PILs recoveries is based on estimated consumption volumes. The difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs amount up to April 30, 2006, is tracked by

LDC as a variance amount in accordance with OEB guidelines for regulatory assets and with criteria set out in the AP Handbook. Commencing May 1, 2006, any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application are tracked by LDC as variance amounts.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property, plant and equipment of LDC. According to the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Spare transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the AP Handbook, spare transformers are treated as capital assets *[note 5]*, which would be recorded as inventory under Canadian GAAP for unregulated businesses.

c) Cash and cash equivalents

Effective January 1, 2006, the Corporation changed the terms to maturity in the definition of cash equivalents from five months or less to 90 days or less from the date of acquisition. This change resulted in no impact on the audited consolidated financial statements as at December 31, 2006 and 2005.

d) Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on an average cost basis net of the provision for obsolescence.

e) Property, plant and equipment and depreciation

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to "Other" in the Consolidated Statement of Income.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

Buildings	1.7% to 10.0%
Stations	2.9% to 5.0%
Distribution lines	2.5% to 25.0%
Transformers	3.3% to 4.0%
Meters	2.9% to 4.0%
Other capital assets	6.7% to 12.5%
Communications	5.0% to 20.0%
Computer hardware	20.0% to 25.0%
Rolling stock	12.5% to 33.3%
Equipment and tools	10.0%

Construction in progress includes assets not currently in use which are not depreciated.

f) Intangible assets

Intangible assets, which lack physical substance, are stated at cost. Amortization is provided on a straight-line basis over their estimated useful service lives at the following annual rates:

Land rights	2.0%
Computer software	14.0% to 33.0%
Capital contributions	4.0%
Leasehold improvements	Over the remaining lease term

Software in development includes assets not currently in use which are not amortized.

g) Deferred debt issue costs

In 2003, the Corporation incurred debt issue costs arising from the Corporation's debenture offering *[note 8]*. Deferred debt issue costs are included in "Other assets" and represent the unamortized amounts of debt costs arising from the issuance of debt, and other related costs. Deferred debt issue costs are amortized over the period to maturity of the debt on a straight-line basis.

h) Workplace Safety and Insurance Act

The Corporation is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act ["WSIA"]. As a Schedule 1 employer, the Corporation is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

i) Revenue recognition and accounting for financial derivative instruments

LDC

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39,800,000. The rate increase was effective as of April 1, 2005 and is subject to a financial commitment by LDC to spend $39,800,000 in CDM activities by September 2007. The revenue of $39,800,000 was billed to customers over a period of 11-months commencing April 1, 2005. At each reporting date, on a life-to-date basis, to the extent the earned customer revenue exceeds the CDM activity spending, the difference is recorded in the balance sheet as "Deferred revenue".

Other income, which includes revenues from electricity distribution related services, is recognized as the services are rendered.

TH Energy

TH Energy has entered into contracts to provide electricity at fixed prices. Electricity contracts are contracts with fixed notional volumes at fixed prices. These contracts expose TH Energy to changes in market prices of electricity and consumption. To reduce its exposure to these changes, TH Energy purchases wholesale electricity physical bilateral and financial contracts.

TH Energy accounts for notional block contracts and non-designated purchase contracts using the mark-to-market method of accounting. Under the mark-to-market method of accounting, TH Energy records the fair value of the contracts, less related reserves, as mark-to-market assets or liabilities at the time of contract execution. All transactions are recognized on a net basis as mark-to-market revenue. Mark-to-market revenue includes gains or losses on new transactions at origination, unrealized gains and losses from changes in the fair value of contracts, net gains or losses from realized transactions and changes in reserves.

TH Energy records reserves for counter-party credit risk and on-going operational expense to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market assets and liabilities. To the extent possible, TH Energy utilizes market-based data together with quantitative methods to determine the level of reserves.

As at December 31, 2006, all retail and wholesale electricity contracts have concluded. TH Energy has no outstanding contracts as at December 31, 2006.

Energy efficiency products and services revenue is accounted for under the percentage of completion method, with revenue recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident.

Water heater revenue is accounted for when the service is rendered.

TH Energy provides certain services to the City at commercial rates, including street lighting and expressway lighting services. Street lighting and expressway lighting services are recognized when services are rendered.

Telecom

Fibre leasing and data communications services revenues are recognized as services are rendered.

j) Employee future benefits

Pension plan

The Corporation provides a pension plan for its full-time employees through Ontario Municipal Employees Retirement System [“OMERS”]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees’ contributory earnings. The Corporation recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension

Employee future benefits other than pension provided by the Corporation include medical and life insurance benefits, accumulated sick leave credits and voluntary exit incentive program liability. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains (losses) over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in the period in which a settlement occurs.

k) Customers' advance deposits

Customers' advance deposits are cash collections from customers to guarantee the payment of energy bills. The customers’ advance deposits liability includes interest credited to the customers’ deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

l) Asset retirement obligations

The Corporation recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in distribution equipment and in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability [“accretion expense”] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation [“ARO”] is incurred and when the fair value is determined.

Effective June 30, 2006, the Corporation adopted Emerging Issues Committee Abstract EIC-159 “Conditional Asset Retirement Obligations” [“EIC-159”]. EIC-159 requires an entity to recognize a liability for the fair value of an ARO even though the timing or method of settlement is conditional on future events. The Corporation has identified

conditional AROs and recognized the related liability in 2006. The adoption has been accounted for prospectively as information is not available to allow it to be accounted for retroactively. The fair value of the identified AROs and the change from prior period are determined to be not material to the Corporation's result of operations and financial position.

m) Use of estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or Minister of Finance.

5. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2006			2005		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**4,088**	**—**	**4,088**	4,136	—	4,136
Buildings	**145,281**	**44,016**	**101,265**	144,048	43,332	100,716
Stations	**191,833**	**99,988**	**91,845**	183,155	94,179	88,976
Distribution lines	**2,069,674**	**1,024,020**	**1,045,654**	1,982,918	942,109	1,040,809
Transformers	**493,878**	**264,308**	**229,570**	471,562	247,102	224,460
Meters	**131,886**	**80,032**	**51,854**	127,468	75,721	51,747
Other capital assets	**44,077**	**30,127**	**13,950**	57,506	41,722	15,784
Communications	**73,041**	**45,629**	**27,412**	61,241	39,290	21,951
Computer hardware	**39,511**	**35,237**	**4,274**	36,593	33,436	3,157
Rolling stock	**57,237**	**44,243**	**12,994**	51,424	40,990	10,434
Equipment and tools	**33,168**	**23,488**	**9,680**	28,086	22,232	5,854
Construction in progress	**64,282**	**—**	**64,282**	56,717	—	56,717
	3,347,956	**1,691,088**	**1,656,868**	3,204,854	1,580,113	1,624,741

At December 31, 2006, spare transformers with carrying amounts of $5,486,000 [2005 - $4,767,000], are included in "Property, plant and equipment, net" *[note 4[b] "Spare transformers"]*. In the absence of rate regulation, inventory would have been $5,486,000 higher [2005 - $4,767,000].

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

6. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2006			2005		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Land rights	**10,229**	**2,022**	**8,207**	10,074	1,819	8,255
Computer software	**118,861**	**86,070**	**32,791**	97,590	72,840	24,750
Leasehold improvements	**693**	**215**	**478**	1,239	383	856
Capital contributions	**2,043**	**197**	**1,846**	2,043	116	1,927
Software in development	**5,944**	**—**	**5,944**	6,138	—	6,138
	137,770	**88,504**	**49,266**	117,084	75,158	41,926

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2006 $	2005 $
Regulatory assets recovery account	**37,510**	55,408
Excess of cash pension contributions	**—**	4,785
Excess of OEB annual cost	**—**	3,559
Smart meters	**29,018**	—
	66,528	63,752

Regulatory liabilities consist of the following:

	2006 $	2005 $
Pre-market opening line loss variance	**2,880**	2,880
Settlement variances	**7,990**	10,417
Other	**970**	—
	11,840	13,297

For the year ended December 31, 2006, LDC recovered approved regulatory assets amounts of $26,877,000 through permitted distribution rate adjustments [2005 - $24,563,000]. These recovery amounts are for the recovery of approved regulatory assets recorded in reporting periods prior to January 1, 2005. In accordance with the OEB's direction, the Corporation recorded carrying charges on the recovered amounts of $nil in 2006 [2005 - $1,544,000].

In the absence of rate regulation, interest income for the year ended December 31, 2006 would have been $nil [2005 - higher by $1,544,000].

For the years ended December 31, 2006 and December 31, 2005, recovery amounts were credited directly to reduce the regulatory assets recovery account. The regulatory assets and liabilities balances of the Corporation are defined as follows:

[a] Regulatory assets recovery account

On March 31, 2005, the OEB ordered that the approved regulatory asset balances be aggregated into a single regulatory account. Approved regulatory assets of $71,465,000 consisted of transition costs of $37,868,000, pre-market opening energy electricity variance of $26,129,000, and settlement variances of $31,852,000, less recoveries of $24,384,000, which were transferred to the "regulatory asset recovery account" ["RARA"]. This approved balance will be recovered over a period ending March 31, 2008. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges. In the absence of rate regulation, interest income in 2006 would have been $1,685,000 lower [2005 - $2,539,000].

The transition costs and pre-market opening energy electricity variance are defined as follows:

[i] Transition costs

The OEB allowed the LDC to defer the costs incurred to align systems and practices with the requirements of the competitive electricity market in Ontario in accordance with the *Ontario Energy Board Act, 1998*. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook.

Under such regulation, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2003 to March 31, 2005, transition costs were increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $558,000 lower.

[ii] Pre-market opening energy electricity variance

The OEB has allowed the LDC to recognize the pre-market opening energy electricity variance for the period January 1, 2001 to April 30, 2002, the date of market opening. The pre-market opening energy variance represented the difference between the LDC's cost of power purchased based upon time-of-use ["TOU"] rates and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2001 to March 31, 2005, the pre-market opening energy electricity variance was increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $370,000 lower.

[b] Excess of cash pension contributions

The OEB has allowed the LDC to defer the incremental OMERS pension expenditures for the fiscal years starting after January 1, 2005 and to end on April 30, 2006. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $6,510,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $1,725,000 higher [2005 - $4,785,000].

[c] Excess of OEB annual cost

The OEB has allowed the LDC to defer a portion of the OEB annual cost assessments for the fiscal years starting after January 1, 2004 and to end on April 30, 2006. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $4,345,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $786,000 higher [2005 - $2,166,000].

[d] Smart Meters

Effective May 1, 2006, the OEB has allowed the LDC to defer capital expenditures, operating expenditures, depreciation expense and revenues relating to smart meters. Accordingly, the Corporation has deferred these items in accordance with the criteria set out in the AP Handbook.

Under such regulation, in 2006, smart meter capital expenditures of $30,347,000 [2005 - $nil] were deferred. These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment in 2006 would have been $30,347,000 higher [2005 - $nil].

In 2006, smart meter operating expenditures of $526,000 [2005 - $nil] were deferred which would be expensed under Canadian GAAP for unregulated businesses., and smart meter depreciation expense of $690,000 [2005 - $nil] was deferred which otherwise would be charged to depreciation expense under Canadian GAAP for unregulated businesses. In the absence of rate regulation, operating expenses and depreciation expense in 2006 would have been $526,000 and $690,000 higher respectively [2005 - $nil and $nil respectively].

In 2006, smart meter customer revenues of $2,966,000 [2005 - $nil] were deferred. In the absence of rate regulation, revenue in 2006 would have been $2,966,000 higher [2005 - $nil].

The deferred balances continue to be calculated and attract carrying charges. In 2006, the Corporation recorded carrying charges of $422,000 [2005 - $nil] on the deferred amounts. In the absence of rate regulation, interest income in 2006 would have been $422,000 lower [2005 - $nil].

The manner and timing of disposition of these smart meter regulatory assets have not been determined by the OEB at this time.

[e] Pre-market opening line loss variance

The OEB has allowed the LDC to defer the pre-market opening line loss variance for the period June 1, 2001 to April 30, 2002. This balance represents the variance between amounts charged by LDC to customers for the OEB-approved loss adjustment factor and the LDC actual loss adjustment factor. Accordingly, the Corporation has deferred this variance in accordance with the OEB's direction.

In the absence of rate regulation, there would have been no impact on the Consolidated Statement of Income for 2006 and 2005. The deferred balance does not attract carrying charges. The manner and timing of disposition of the variance have not been determined by the OEB.

[f] Settlement variances

The OEB has allowed the LDC to defer settlement variances from May 1, 2002 to December 31, 2006. This balance represents the variances between amounts charged by LDC to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by LDC after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

Settlement variances of $27,980,000, relating to the period from May 1, 2002 to December 31, 2004, were approved for recovery by the OEB and are included in the RARA balance. The remaining balance, representing settlement variances arising after January 1, 2005, is deferred in a regulatory liability account.

In the absence of rate regulation, interest income in 2006 would have been $49,000 lower [2005 - $1,112,000]. The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance have not been determined by the OEB.

8. OTHER ASSETS

Other assets consist of the following:

	2006 $	2005 $
Deferred debt issue costs, net of accumulated amortization of $1,412,000 [2005 - $1,025,000]	**2,457**	2,843
Long-term advances and deposits	**—**	1,566
Other	**121**	1,081
	2,578	5,490

9. BANK INDEBTEDNESS AND BANKERS' ACCEPTANCES

On May 5, 2005, the Corporation extended its revolving credit facility with a syndicate of Canadian banks [the "Revolving Credit Facility"] for a three-year period to May 4, 2008. Under the terms of the revolving credit facility, the Corporation may borrow up to $500,000,000, of which:

[a] $500,000,000 less the amount utilized under [b] is available for working capital purposes in the form of prime rate loans in Canadian dollars and bankers' acceptances; and

[b] up to $175,000,000 is available in the form of letters of credit to support the prudential requirements of LDC and TH Energy and general credit requirements of the Corporation and its subsidiaries.

The facility contains a negative pledge, customary covenants and events of default.

At December 31, 2006, $81,620,000 [December 31, 2005 - $90,174,000] had been utilized under the revolving credit facility in the form of letters of credit to support the prudential requirements of LDC [$80,000,000] [2005 - $80,000,000], TH Energy [$780,000] [2005 - $9,194,000] and Telecom [$840,000] [2005 - $980,000]. At December 31, 2006, no amounts had been drawn for working capital purposes [December 31, 2005 - $nil].

The Corporation also has a bilateral demand line of credit for $20,000,000 with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate [December 31, 2006 – 6%]. At December 31, 2006, no amounts had been drawn on the line of credit [December 31, 2005 - $nil].

10. CURRENT PORTION OF OTHER LONG-TERM LIABILITIES

Current portion of other long-term liabilities consist of the following:

	2006 $	2005 $
Current portion of obligations under capital leases *[note 20]*	**733**	1,877
Customers' advance deposits	**15,904**	37,029
Other	**315**	304
	16,952	39,210

11. LONG-TERM DEBT

Long-term debt consists of the following:

	2006 $	2005 $
Senior unsecured debentures	**225,000**	225,000
Promissory note payable to the City	**980,231**	980,231
	1,205,231	1,205,231
Less: Current portion of promissory note payable to the City	**245,058**	330,000
Long-term debt	**960,173**	875,231
Comprising:		
Debentures	**225,000**	225,000
Promissory note payable to the City	**735,173**	650,231

All debt of the Corporation ranks equally.

a) Senior unsecured debentures

On May 7, 2003, the Corporation issued $225,000,000 10-year senior unsecured debentures. The Corporation's 10-year senior unsecured debentures in the amount of $225,000,000, as at December 31, 2006, [December 31, 2005 - $225,000,000] bear interest at a rate of 6.11% per annum, payable semi-annually in arrears in equal instalments on May 7 and November 7 of each year. The debentures mature on May 7, 2013.

The Corporation may redeem some or all of the debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to but excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any price. The debentures have the benefit of certain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

b) Promissory note payable to the City of Toronto

LDC issued a promissory note to the City on July 1, 1999 ["Initial Note"] in the principal amount of $947,000,000 in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. Pursuant to the Transfer By-law, the principal amount of the Initial Note was adjusted effective January 1, 2000 to $980,231,000 to reflect the deemed debt to equity structure of LDC [65:35] permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note ["Replacement Note"] issued by LDC, which was interest bearing at the rate of 6.8% per annum. At December 31, 2002, the Replacement Note was payable on the earlier of demand and December 31, 2003.

Concurrent with the closing of the debenture offering on May 7, 2003, the City transferred the Replacement Note to the Corporation in consideration for the issue by the Corporation to the City of a new promissory note in the

principal amount of $980,231,000 [2005 – $980,231,000] [the "City Note"]. At December 31, 2005 the principal amount of the City Note, together with accrued interest thereon, was payable:

[a] on demand on not less than 90 days written notice until May 7, 2006; and

[b] in accordance with a payment schedule to be delivered by the City at least 90 days before May 7, 2006;

provided that the Corporation will not be required to pay more than $330,000,000 of the principal amount of the City Note during any twelve-month period. Accordingly, $330,000,000 of the principal amount outstanding under the City Note was classified as a current liability. In 2005 the maximum term of the City Note was ten years.

On September 5, 2006, the Corporation announced that it and the City had amended and restated the City Note effective May 1, 2006 by fixing the interest rate at 6.11% and establishing an agreed repayment schedule. The Corporation is required to pay the principal amount of the note as follows: $245,058,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and on May 6, 2013. Accordingly, $245,058,000 of the principal amount outstanding under the City Note is classified as a short-term liability, with the remainder being classified as a long-term liability. Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year.

12. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2006, the Corporation's OMERS current service pension costs were $10,343,000 [2005 - $8,965,000].

Employee future benefits other than pension

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits [excluding pension] to most of its employees. The Corporation pays certain medical and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The Corporation measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2005. The December 31, 2006 year-end accrued benefit obligation reflects a December 31, 2006 discount rate. This result was achieved by updating the January 1, 2005 actuarial valuation using the December 31, 2006 discount rate of 5.3% while keeping all other assumptions constant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

[a] Accrued benefit obligation

	2006 $	2005 $
Balance at beginning of year	**167,013**	139,468
Experience gain at beginning of year	—	(1,446)
Current service cost	**3,907**	3,152
Interest cost	**8,412**	8,178
Benefits paid	**(5,372)**	(4,988)
Actuarial (gains) losses	**(6,499)**	22,649
Balance at end of year	**167,461**	167,013

[b] Reconciliation of the accrued benefit obligation to the balance sheet accrued benefits liability

	2006 $	2005 $
Accrued benefit obligation	**167,461**	167,013
Unamortized net actuarial loss	**(26,593)**	(34,427)
Unamortized past service costs	**(6,186)**	(7,171)
Post-employment benefits liability	**134,682**	125,415

[c] Components for net periodic defined benefit costs

	2006 $	2005 $
Current service cost	**3,907**	3,152
Interest cost	**8,412**	8,178
Actuarial (gains) losses	**(6,499)**	21,203
Cost incurred in the year	**5,820**	32,533
Differences between costs incurred and costs recognized in the year in respect of:		
Actuarial loss (gain)	**7,789**	(21,230)
Past service costs	**985**	983
	8,774	(20,247)
Defined benefit costs recognized	**14,594**	12,286
Capitalized as part of property, plant and equipment	**6,385**	3,672
Charged to operations	**8,209**	8,614

[d[Significant assumptions

	2006 %	2005 %
Accrued benefit obligation as of December 31:		
Discount rate	**5.3**	5.0
Rate of compensation increase	**4.0**	4.0
Benefit costs for years ended December 31:		
Discount rate	**5.0**	5.9
Rate of compensation increase	**4.0**	4.0
Assumed health care cost trend rates at December 31:		
Rate of increase in dental costs	**4.5**	4.5

For December 31, 2006 and 2005, medical costs are assumed to increase at 10.5% graded down by 1.0% annual decrements to 4.5% in 2011 and thereafter.

[e] Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates have the following effects for 2006:

	Increase $	Decrease $
Net periodic benefit cost (at 5.0%)	**2,282**	**(1,699)**
Accrued benefit obligation at December 31, 2006 (at 5.3%)	**27,682**	**(21,182)**

13. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following:

	2006 $	2005 $
Obligations under capital leases *[note 20]*	**1,033**	2,063
Security deposits	**1,575**	3,277
Lease liability – long-term	**—**	285
Other	**1,341**	3,452
	3,949	9,077

During 2006, the Corporation acquired "Property, plant and equipment" through capital lease transactions totaling $556,000 [2005 - $43,000]. These non-cash transactions have been excluded from the Consolidated Statement of Cash Flows.

14. ASSET RETIREMENT OBLIGATIONS

A reconciliation between the opening and closing ARO liability balances is as follows:

	2006 $	2005 $
Balance, beginning of year	**5,691**	4,274
ARO liabilities incurred in the year	**2,039**	1,525
ARO liabilities settled in the year	**(509)**	(351)
Accretion expense	**360**	243
Balance, end of year	**7,581**	5,691

At December 31, 2006, the Corporation estimates the undiscounted amount of cash flows required over the next ten years to settle the ARO is $11,372,000 [2005 - $6,836,000]. Discount rates ranging from 4.3% to 6.0% were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

15. FINANCIAL INSTRUMENTS

Electricity retailing commitments

In December 2002, TH Energy ceased new electricity retailing activities in respect of new customers as a result of the price freeze implemented under Bill 210. TH Energy managed the remaining portfolio of electricity contracts comprised primarily of fixed notional volume contracts, wholesale financial fixed notional volume fixed-for-floating and floating-for-fixed swaps and fixed notional volume physical bilateral contracts. The contracts are derivative contracts for accounting purposes. The electricity contracts had varying maturity dates throughout the period ending December 31, 2006.

At December 31, 2006, TH Energy had floating-for-fixed electricity contracts that had an aggregate expected contract volume and value of nil MWh and $nil [2005 – 3,124,000 MWh and $171,270,000].

To hedge the volume and price risk inherent in retailing electricity, TH Energy entered into financial fixed notional volume fixed-for-floating swaps and fixed notional physical bilateral contracts with generators and marketers. At December 31, 2006, the aggregate notional volume and value of these contracts were nil MWh and $nil [2005 – 3,614,000 MWh and $154,396,000].

For the year ended December 31, 2006, "Revenues" include $20,661,000 of electricity mark-to-market revenues [2005 - $34,309,000].

Credit risk

Financial instruments result in exposure to credit risk stemming from the risk of the counter-party defaulting on its obligations. TH Energy monitors and limits its exposure to counter-parties with lower credit ratings and evaluates its counter-party credit exposure on a continuous basis. TH Energy obtains collateral from some counter-parties and seeks to deal only with counter-parties with investment-grade credit ratings. TH Energy had five wholesale counter-parties as at December 31, 2006 for its electricity supply portfolio. In addition, TH Energy provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties. The largest single credit exposure at December 31, 2006 is estimated at $12,382,389, which is the December 2006 invoice of power sold to one counter party [2005 - $137,170,000].

For retail customers, credit losses are generally low across the sector. LDC, TH Energy and Telecom provide for an allowance for doubtful accounts to absorb credit losses. At December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets other than the risk mentioned above.

Interest rate risk

The Corporation is exposed to interest rate risk for certain of its financial assets and liabilities. Under the Corporation's Revolving Credit Facility *[note 9]*, the Corporation may have short-term borrowings for working capital purposes. These borrowings would expose the Corporation to fluctuations in short-term interest rates [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Corporation's credit rating.

Certain cash balances of the Corporation is invested in Canadian money market instruments, with terms of one day to 90 days, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Fair value of financial instruments

The carrying value of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximates their fair value due to the immediate or short-term maturity of these financial instruments**.**

At December 31, 2006, the fair values of the City Note [$980,231,000] and the senior unsecured debentures [$225,000,000] are $1,034,640,000 and $247,515,000 [2005 - $1,120,405,000 and $251,415,000]. These fair values have been calculated by discounting the future cash flow of the respective long-term debt at the estimated yield to maturity of similar debt instruments *[note 11]*.

The fair value of hedging derivative financial instruments is the estimated amount the Corporation would receive (pay) to terminate the contracts. The value is based on market prices or management's best estimates if there is no organized market and/or if the market is illiquid.

All retail fixed notional volume fixed price contracts and all undesignated wholesale fixed notional volume fixed-for-floating swaps and fixed notional volume physical bilateral contracts are accounted for using the mark-to-market method of accounting. The following are the primary sources of the change in the net mark-to-market assets:

	2006 $	2005 $
Net mark-to-market assets		
Fair value, beginning of year	**26,422**	27,696
Unrealized change in fair value during the period	**(4,431)**	16,342
Realization of contracts for the period	**(21,991)**	(17,616)
Fair value of net mark-to-market assets, end of year	**—**	26,422

16. FINANCIAL GUARANTEES

Participants [including LDC and TH Energy] in the wholesale market for electricity are required to satisfy prescribed prudential requirements. In addition, counter-parties under contracts for the purchase and sale of electricity and customers under purchase contracts may require parental financial guarantees or other forms of credit support.

The City has authorized the Corporation to provide up to $500,000,000 in financial support [including guarantees] with respect to prudential requirements and as security for obligations under third party contracts.

At December 31, 2006, the Corporation's board of directors had approved $386,000,000 in parental guarantees on behalf of TH Energy, of which $56,500,000 has been issued to unrelated parties [2005 - $86,500,000].

The Corporation has issued a parental guarantee to the City as part of an agreement to purchase electricity at a fixed price from TH Energy. The fair value of the parental guarantee was $nil at December 31, 2006 [2005 - $56,417,000]

17. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. Reconciliation between the statutory and effective tax rates is set out below:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Consolidated Statement of income

	2006 $	2005 $
Rate reconciliation		
Income before PILs	**148,622**	159,756
Consolidated Statutory Canadian federal and provincial income tax rate	**36.12%**	36.12%
Expected provision for PILs	**53,682**	57,704
Increase in income taxes resulting from large corporations tax net of surtax	**—**	1,655
Temporary differences not benefited	**3,482**	10,630
Valuation allowance	**1,150**	(2,056)
Decrease in federal future tax rates	**2,215**	—
Other	**(2,126)**	906
Provision for PILs	**58,403**	68,839
Effective tax rate	**39.30%**	43.09%
Components of provision for PILs		
Current tax provision	**60,890**	71,960
Future income tax recovery related to the origination and reversal of temporary differences	**(2,487)**	(3,121)
Provision for PILs	**58,403**	68,839

Consolidated Balance sheet

Significant components of the Corporation's future income tax assets and liabilities are as follows:

	2006 $	2005 $
Non-capital loss carryforwards	**576**	2,785
Property, plant and equipment and intangible assets	**27,968**	32,153
Other taxable temporary differences	**4,735**	(4,998)
Valuation allowance	**(16,847)**	(15,973)
	16,432	13,967

Presented on the consolidated balance sheet as follows:

	2006 $	2005 $
Future income tax assets, current	**791**	33,195
Future income tax assets, long-term	**16,009**	22,264
Future income tax liabilities, current	**—**	(40,923)
Future income tax liabilities, long-term	**(368)**	(569)
	16,432	13,967

Under the taxes payable method applicable to LDC, no adjustments are made for differences between the financial statement carrying values and the tax basis of assets and liabilities. As at December 31, 2006, future income tax assets of $234,217,000 [2005 - $249,838,000], based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Corporation's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs in 2006 would have been $3,482,000 lower [2005 – $7,863,000 lower][*note 4 [b]*].

As at December 31, 2006, the Corporation has accumulated tax losses for PILs purposes of approximately $1,744,000, which are available to reduce future years' taxable income. These loss carryforwards begin to expire in 2008.

As at December 31, 2006, LDC has accumulated a PILs variance amount, representing the difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs, totaling an under-recovery of $10,286,000 [2005 -$4,948,000]. LDC has also accumulated a PILs variance amount representing differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application totalling an over-recovery of $1,702,000 [2005 - $ nil]. Cumulative interest included in the amounts was calculated following OEB direction and totaled $3,004,000 [2005 - $2,858,000].

18. SHARE CAPITAL

Share capital consists of the following:

	2006 $	2005 $
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares		
Issued and outstanding		
1,000 common shares	**567,817**	567,817

Dividends

The shareholder direction adopted by the City with respect to the Corporation provided that the Corporation's board of directors would use its best efforts to ensure that the Corporation met certain financial performance standards, including those relating to credit rating and dividends. Subject to applicable law, the shareholder direction provided that the Corporation would pay dividends to the City each year.

Subject to applicable law and the shareholder direction, the amount of the annual dividends payable by the Corporation to the City is to be the greater of $25,000,000 or 50% of the Corporation's annual consolidated net income. The dividends are not cumulative and are payable as follows:

[a] $6,000,000 on the last day of each of the first three fiscal quarters in each year;

[b] $7,000,000 on the last day of the fiscal year; and

[c] the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25,000,000 within ten days after the board of directors of the Corporation approves the Corporation's audited consolidated financial statements for the year.

During 2006, the board of directors of the Corporation declared and paid dividends totaling $46,200,000 to the City [2005 - $68,000,000].

19. RELATED PARTIES

For the Corporation, transactions with related parties include transactions with the City. All transactions with the City are conducted at prevailing market prices and normal trade terms.

For the year ended December 31, 2006, LDC provided street lighting electricity to the City in the amount of $9,281,000 [2005 - $11,089,000].

For the year ended December 31, 2006, TH Energy invoiced the City for electricity for $102,771,000 [2005 - $107,450,000]. At December 31, 2006, included in "Accounts receivable, net of allowance for doubtful accounts" are $5,905,000 [2005 - $1,257,000] receivable from the City related to these electricity billing activities.

For the year ended December 31, 2006, TH Energy provided energy efficiency products and services to the City amounting to $2,010,000 [2005 - $1,927,000].

On December 31, 2005, TH Energy acquired the street lighting and expressway lighting assets from the City for cash consideration of $60,000,000. The transaction was recorded at the exchange amount, which is reflective of the fair market value, as an increase in property, plant and equipment. The acquisition of these assets was recorded at the exchange amount since the carrying value of the assets in the City's records was not determinable. The purchase price was supported by an independent valuation of the fair market value of the acquired assets. The acquired assets are being depreciated over their estimated remaining service lives.

Concurrently with the transaction, the Corporation entered into a service agreement with the City to provide street lighting and expressway lighting services to the City for a period of 30 years commencing January 1, 2006. During

2006, TH Energy provided street and expressway lighting services to the City totalling $15,287,000 [2005 - $4,712,000].

For the year ended December 31, 2006, LDC incurred property taxes payable to the City of $7,306,000 [2005 - $7,030,000].

At December 31, 2006, a promissory note in the amount of $980,231,000 [2005 - $980,231,000] was payable to the City. For the year ended December 31, 2006, interest expense of $59,892,000 [2005 - $66,656,000], on the promissory note was paid to the City *[note 11]*.

20. LEASE COMMITMENTS

Operating lease obligations

As at December 31, 2006, the future minimum annual lease payments under property and computer hardware operating leases with remaining lease terms from one to five years are as follows:

	$
2007	**4,646**
2008	**5,793**
2009	**5,567**
2010	**5,498**
2011	**5,018**
Thereafter	**2,953**
Total minimum lease payments	**29,475**

Capital lease obligations

As at December 31, 2006, the future minimum annual lease payments under vehicle capital leases with remaining lease terms from one to five years are as follows:

	$
2007	**733**
2008	**562**
2009	**552**
2010	**160**
Thereafter	**11**
Total amount of future minimum lease payments	**2,018**
Less interest	**252**
	1,766
Current portion *[note 10]*	**733**
Long-term portion *[note 13]*	**1,033**

21. CONTINGENCIES

a) Ministry of Finance Tax Audit

The Ministry of Finance is currently carrying out a tax audit on the Corporation and its subsidiaries. Certain filing positions for PILs taken by the Corporation and its subsidiaries may be challenged on the audit. This may result in a material increase in the Corporation's reported tax obligations upon reassessment. As the audit has not yet been completed, management is not able to determine the impact, if any, of the audit on the consolidated financial statements or the Corporation's tax reserves. The Corporation adjusts its tax reserves when there is sufficient information available, or when an event occurs requiring a change to the reserves.

b) Consumers' Gas Decision

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada [the "Supreme Court"] ruled that The Consumers' Gas Company ["Consumers' Gas"] was required to repay the portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the *Criminal Code* in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement, however, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff, and to receive lawyer's fees in connection with that effort. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario municipal electric utilities under the Class Proceedings Act, 1992 seeking $500,000,000 in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the Class Proceedings Act, 1992 seeking $64,000,000 in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is also at the preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the *Criminal Code* is fact specific in each circumstance. Accordingly, given the preliminary status of these actions, it is not possible at this time to quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

22. NET INCOME PER SHARE

The weighted daily average numbers of shares outstanding were 1,000 as at December 31, 2006 and 2005, for purposes of determining basic and fully diluted net income per share for continuing and discontinued operations. Basic and fully diluted net income per share for continuing and discontinued operations were determined by dividing the net income for the year by the weighted daily average number of shares outstanding.

23. DISCONTINUED OPERATIONS

In November 2006, the Board of Directors of TH Energy approved a plan to sell the water heater assets and to exit this business segment. Accordingly, the results of operations and financial position of the water heater business have been segregated and presented as discontinued operations in the accompanying financial statements. As at December 31, 2006, the net assets of the water heater business have been measured and presented at the lower of the carrying amount or fair value less cost to sell. The net assets held for sale are as follows:

	$
Current assets held for sale:	
Property, plant and equipment	**12,098**
	12,098
Current liabilities held for sale:	
Accounts payable	**103**
Future income tax liabilities	**803**
	906

For the year ended December 31, 2006 and 2005, the following revenue and expenses of the water heater business have been reclassified from continuing operations to discontinued operations:

	2006 $	2005 $
Sales	**8,085**	8,147
Expenses		
Purchased power and other	**1,820**	1,753
Operating expenses	**879**	319
Depreciation and amortization	**2,405**	3,498
	5,104	5,570
Provision of payments in lieu of corporate taxes	**803**	1,049
Income from discontinued operations	**2,178**	1,528

24. SEGMENT REPORTING

The designation of the segments has been based on a combination of the regulatory status and the nature of products and services provided. The Corporation has two reportable segments:

[a] Electricity Distribution:
the regulated business which consists of the electricity distribution business of LDC; and

[b] Non-regulated:
the non-regulated business of TH Energy which consist primarily of the delivery of street lighting and expressway lighting services, the sale of energy management services, and up until December 31, 2006, the management of a portfolio of electricity contracts. The non-regulated business of Telecom which consists of the provision of fibre optic capacity and data communications services to telecommunications carriers, business customers and large institutions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Segment information on the above basis is as follows:

	2006 $	2005 $
Electricity Distribution		
Revenues	**2,264,469**	2,709,819
Purchased power and other	**1,784,144**	2,224,034
Depreciation and amortization	**124,560**	124,988
Interest income	**11,225**	10,485
Interest expense	**76,537**	80,620
Segment profit before interest, other items and provision for payments in lieu of corporate taxes	**186,701**	193,658
Payment in lieu of corporate taxes	**46,001**	61,114
Non-regulated		
Revenues	**75,530**	103,434
Purchased power and other	**14,654**	42,331
Depreciation and amortization	**12,784**	6,607
Interest income	**84,520**	81,865
Interest expense	**80,278**	80,717
Segment profit before interest, other items and provision for payments in lieu of corporate taxes	**22,902**	30,045
Payment in lieu of corporate taxes	**12,402**	7,725
Intersegment eliminations		
Revenues	**(92,991)**	(206,981)
Purchased power and other	**(92,953)**	(206,576)
Interest income	**(78,019)**	(78,234)
Interest expense	**(78,019)**	(78,234)

	2006 $	2005 $
Total		
Revenues	**2,247,008**	2,606,272
Purchased power and other	**1,705,845**	2,059,789
Depreciation and amortization	**137,344**	131,595
Interest income	**17,726**	14,116
Interest expense	**78,796**	83,103
Income before interest, other items and provision for payments in lieu of corporate taxes	**209,603**	223,703
Payment in lieu of corporate taxes	**58,403**	68,839

	2006 $	2005 $
Expenditures on property, plant and equipment and intangible assets		
Electricity Distribution	**167,685**	132,260
Non-regulated	**22,934**	68,095
Intersegment eliminations	**(5,312)**	—
Total	**185,307**	200,355

	2006 $	2005 $
Assets		
Electricity Distribution	**2,280,811**	2,393,533
Non-regulated	**1,505,987**	1,619,790
Intersegment eliminations	**(1,207,190)**	(1,194,065)
Discontinued operations	**12,098**	—
Total	**2,591,706**	2,819,258

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. COMPARATIVE CONSOLIDATED FINANCIAL STATEMENTS

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the 2006 consolidated financial statements.

26. SUBSEQUENT EVENTS

Regulatory Affairs

On January 26, 2007, LDC filed an Annual Rate Adjustment Application for 2007 Rates as directed to by the OEB. In accordance with the OEB's Incentive Regulation Model, LDC has sought authorization to increase its rates by 0.4% on May 1, 2007.

Sale of water heater business

On February 8, 2007, TH Energy sold its water heater business to Consumers' Waterheater Income Fund for cash consideration of $40,800,000 subject to post closing adjustments and transaction costs. This transaction will be recorded in the financial statements in 2007.

Dividends

On March 1, 2007, the board of directors of the Corporation declared a dividend in the amount of $27,199,000. The dividends are comprised of a $21,199,000 payment for 2006 net income, payable to the City on March 9, 2007 and a $6,000,000 payment in connection with the first quarter of 2007, payable to the City on March 30, 2007.

PRO FORMA FINANCIAL STATEMENTS

The THESL annual pro forma financial statements for the years ended 2008, 2009, and 2010 are included in Appendix A of this Exhibit.

These pro forma financial statements are based on current plans, estimates, and projections into the future. The balances and results of operations presented in these financial statements are based upon numerous assumptions that may or may not materialize as expected and the projections are subject to numerous risks and uncertainties, many of which are difficult to predict and are generally beyond THESL's control. If risks or uncertainties materialize, or if the underlying assumptions prove to be incorrect, THESL's actual results may be materially different from those expressed or implied by such statements. Readers should consider these factors when reading the pro forma financial statements.

Version 6

BALANCE SHEET

[in thousands of dollars]

As at December 31	Actual 2006 $	Forecast 2007 $	Projection 2008 $	Projection 2009 $	Projection 2010 $
ASSETS					
Current					
Cash and cash equivalents	**157,391**	105,379	28,483	26,039	30,410
Accounts receivable, net of allowance for doubtful accounts	**191,841**	152,270	165,998	171,231	174,185
Unbilled revenue	**226,297**	249,312	247,726	249,414	250,431
Inventories	**22,458**	20,870	18,900	18,200	17,350
Prepaid expenses	**970**	78	1,091	1,357	1,388
Total current assets	**598,957**	**527,909**	462,198	466,241	473,764
Property, plant and equipment, net	**1,566,718**	1,636,838	1,831,021	1,954,605	2,071,643
Intangible assets, net	**46,658**	57,611	72,774	90,044	108,569
Regulatory assets	**66,528**	86,247	-	-	-
Other assets	**1,950**	4,898	4,566	8,786	7,969
Total assets	**2,280,811**	**2,313,503**	2,370,559	2,519,676	2,661,945
LIABILITIES AND SHAREHOLDER'S EQUITY					
Current					
Accounts payable and accrued liabilities	**242,894**	212,159	217,582	222,371	223,240
Current portion of other liabilities	**16,637**	17,058	21,036	20,694	20,595
Deferred revenue	**4,647**	-	-	-	-
Current portion of promissory note payable to related party	**245,058**	-	245,058	-	245,058
Total current liabilities	**509,236**	**229,217**	483,676	243,065	488,893
Long-term liabilities					
Long-term note payable to related party	**180,000**	180,000	180,000	180,000	180,000
Long-term promissory note payable to related party	**735,173**	980,231	735,173	1,055,231	865,173
Post-employment benefits	**122,344**	137,027	145,155	153,457	161,978
Regulatory liabilities	**11,840**	21,245	9,916	15,892	22,199
Other liabilities	**2,611**	511	1,773	1,691	1,575
Asset retirement obligations	**7,581**	7,913	7,885	6,098	6,220
Customers' advance deposits	**25,944**	26,344	26,036	19,023	18,997
Total long-term liabilities	**1,085,493**	**1,353,271**	1,105,938	1,431,392	1,256,142
Total liabilities	**1,594,729**	**1,582,488**	1,589,614	1,674,457	1,745,035
Shareholder's equity					
Share capital	**527,817**	527,817	527,817	527,817	527,817
Retained earnings	**145,508**	190,441	240,371	304,645	376,336
Contributed surplus	**12,757**	12,757	12,757	12,757	12,757
Total shareholder's equity	**686,082**	**731,015**	780,945	845,219	916,910
Total liabilities and shareholder's equity	**2,280,811**	**2,313,503**	2,370,559	2,519,676	2,661,945

Version 6

STATEMENT OF RETAINED EARNINGS
[in thousands of dollars]

Year ended December 31	Actual 2006 $	Forecast 2007 $	Projection 2008 $	Projection 2009 $	Projection 2010 $
Retained earnings, beginning of year	117,322	145,508	190,441	240,371	304,645
Net income	75,986	69,933	74,930	89,274	96,691
Dividends	(47,800)	(25,000)	(25,000)	(25,000)	(25,000)
Retained earnings, end of year	145,508	190,441	240,371	304,645	376,336

Version 6

STATEMENT OF INCOME

[in thousands of dollars]

Year ended December 31	Actual 2006 $	Forecast 2007 $	Projection 2008 $	Projection 2009 $	Projection 2010 $
Revenues					
Sale of electricity	2,242,993	2,352,086	2,426,993	2,464,837	2,489,842
Other income	21,476	31,348	22,348	21,839	26,031
	2,264,469	2,383,434	2,449,341	2,486,676	2,515,873
Costs					
Purchased power	1,784,144	1,918,534	1,920,420	1,919,396	1,919,156
Operating expenses	169,064	178,607	202,710	212,523	217,852
Depreciation and amortization	124,560	132,415	153,724	160,886	174,420
	2,077,768	2,229,556	2,276,854	2,292,805	2,311,428
Income before interest, other and provision for payments in lieu of corporate taxes	186,701	153,878	172,487	193,871	204,445
Interest income	11,225	7,115	3,073	(701)	(522)
Interest expense					
Long-term notes	(74,024)	(64,421)	(64,263)	(67,038)	(71,848)
Other interest	(2,513)	(572)	59	595	1,001
Other	598	-	-	-	-
Income before provision for payments in lieu of corporate taxes	121,987	96,000	111,356	126,727	133,076
Provision for payments in lieu of corporate taxes	46,001	26,067	36,426	37,453	36,385
Net income	75,986	69,933	74,930	89,274	96,691

Version 6

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	Actual 2006 $	Forecast 2007 $	Projection 2008 $	Projection 2009 $	Projection 2010 $
OPERATING ACTIVITIES					
Net income	75,986	69,933	74,930	89,274	96,691
Adjustments for non-cash items					
Depreciation and amortization	124,560	132,415	153,724	160,886	174,420
Net change in other assets and liabilities	4,771	9,967	9,694	2,212	9,346
Gains on disposals of property, plant and equipment	(598)	(11,282)	(747)	-	(3,900)
Changes in non-cash working capital balances					
Decrease (increase) in accounts receivable	(49,390)	39,571	(13,728)	(5,233)	(2,954)
Decrease (increase) in unbilled revenue	55,478	(23,015)	1,587	(1,688)	(1,018)
Decrease (increase) in inventories	(4,269)	1,588	1,970	700	850
Decrease (increase) in prepaid expenses	(812)	892	(1,013)	(265)	(31)
Increase (decrease) in accounts payable and accrued liabilities	(131,744)	(30,735)	5,422	4,790	869
Increase (decrease) in deferred revenue	(14,990)	(4,647)	-	-	-
Increase (decrease) in current portion of other liabilities	(34)	421	3,978	(342)	(99)
Net cash provided by (used in) operating activities	58,958	185,108	235,817	250,334	274,174
INVESTING ACTIVITIES					
Purchase of property, plant and equipment	(150,952)	(191,272)	(344,604)	(277,497)	(292,214)
Purchase of intangible assets	(16,733)	(22,403)	(24,919)	(24,243)	(18,370)
Net change in regulatory assets and liabilities	(4,233)	(10,314)	74,918	5,975	6,307
Proceeds on disposal of property, plant and equipment	6,738	11,469	7,200	-	4,500
Net cash provided by (used in) investing activities	(165,180)	(212,520)	(287,405)	(295,765)	(299,777)
FINANCING ACTIVITIES					
Increase (decrease) in customers' advance deposits	1,835	400	(308)	(7,013)	(26)
Increase (decrease) in long-term debt	-	-	-	75,000	55,000
Repayment of capital lease liability	(1,182)	-	-	-	-
Dividends paid	(47,800)	(25,000)	(25,000)	(25,000)	(25,000)
Net cash provide by (used in) financing activities	(47,147)	(24,600)	(25,308)	42,987	29,974
Net increase (decrease) in cash and cash equivalents during the year	(153,369)	(52,012)	(76,896)	(2,444)	4,371
Cash and cash equivalents, beginning of year	310,760	157,391	105,379	28,483	26,039
Cash and cash equivalents, end of year	157,391	105,379	28,483	26,039	30,410

AUDITED FINANCIALS AND RRR FILINGS RECONCILIATIONS

The reconciliation of the THESL net income presented in the audited financial statements (refer to Exhibit B1, Tab 6, Schedule 1) and net income included in the Reporting and Record-Keeping Requirements ("RRR") filing, for the year ended December 31, 2006, is presented below.

Table 1: Net Income included in RRR for year-end December 31, 2006

Net Income (in $ millions)	2005 Actual	2006 Actual
Audited Financial Statements	$65.374	$75.986
RRR (USofA Account 3046)	$65.374	$75.986
Difference	Nil	Nil

ACCOUNTING TREATMENT FOR LONG-LIVED ASSETS

Long-lived assets include property, plant and equipment and intangibles that are subject to amortization. The following information relates to the accounting treatment of long-lived assets as reflected in the notes to the audited financial statements (refer to Exhibit B1, Tab 6, Schedule 1).

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to “Other income” in the Statement of Income.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future discounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the assets exceeds its fair value.

toronto hydro corporation

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2006

March 1, 2007

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PART 1 - FORWARD-LOOKING INFORMATION

Certain information included in this Annual Information Form constitutes "forward-looking information". Forward-looking information means disclosure regarding possible events, conditions or results that is based on assumptions about future economic conditions and courses of action or attributable to third parties. In some cases, forward-looking information can be identified by terminology such as "may", "will", "should", "expect", "anticipate", "believe", "estimate", "predict", "potential", "continue", "plan" and similar expressions or the negative of these terms or other comparable terminology. Although the Corporation believes that it has a reasonable basis for the forward-looking information included in this Annual Information Form, such information is subject to a number of risks, uncertainties and assumptions, including those discussed in the "Risk Factors" section and elsewhere in this Annual Information Form that may cause actual events, conditions or results to differ materially from those contemplated by the forward-looking information. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the ratings assigned to the Corporation or its debt securities by rating agencies. Except to the extent required by applicable securities laws and regulations, the Corporation does not undertake any obligation to update publicly or to revise any of the forward-looking information included in this Annual Information Form or incorporated by reference herein after the date thereof, whether as a result of new information, future events or circumstances or otherwise.

PART 2 - GLOSSARY OF DEFINED TERMS

"**Affiliate Relationships Code**" refers to the Affiliate Relationships Code for Electricity Distributors and Transmitters which was published by the OEB and became effective on April 1, 1999, as amended.

"**Amended and Restated City Note**" refers to the amended and restated City Note dated May 1, 2006 in the principal amount of $980,230,955. See note 11 to the Consolidated Financial Statements.

"**Capital Assets**" refers to the sum of property, plant and equipment and intangible assets, in each case, net of accumulated amortization. See note 4(e), note 4(f), note 5 and note 6 to the Consolidated Financial Statements.

"**Capital Expenditures**" refers to expenditures relating to property, plant and equipment and intangible assets.

"**CDM**" refers to Conservation and Demand Management.

"**City Note**" refers to the promissory note dated May 7, 2003 in the principal amount of $980,230,955 issued by the Corporation to the City of Toronto in consideration for the transfer by the City to the Corporation of the Replacement Note. See note 11 to the Consolidated Financial Statements.

"**City**" or "**City of Toronto**" refers to the city incorporated under the *City of Toronto Act, 1997* and comprised of the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York.

"**Consolidated Financial Statements**" refers to the audited consolidated balance sheets of the Corporation as at December 31, 2006 and 2005 and the audited consolidated statements of retained earnings, income and cash flows of the Corporation for the years ended December 31, 2006 and December 31, 2005 together with the auditors' report thereon and the notes thereto, copies of which are included in this Annual Information Form as Annex A.

"**Consumer Price Index**" refers to the index measuring price movements published by Statistics Canada.

"**Corporation**" refers to Toronto Hydro Corporation.

"**CRTC**" refers to the Canadian Radio Television and Telecommunications Commission.

"**DBRS**" refers to Dominion Bond Rating Service Limited.

"**Debentures**" refers to the 6.11% Senior Unsecured Debentures issued by the Corporation on May 7, 2003. See note 11 to the Consolidated Financial Statements.

"**Designated Consumers**" refers to a class of consumers of electricity comprised principally of municipalities, universities, schools, hospitals, charities, health and community service organizations, consumers with a demand of 50kW or less, multi-unit residential buildings and such other consumers as may be prescribed by regulation.

"**Distribution System Code**" refers to the Distribution System Code which was published by the OEB on July 14, 2000 and became effective on the commencement of Open Access (except with respect to "Connections and Customer Charges", "Expansions", "Alternative Bids", "Enhancements" and "Charges to Generators", which came into effect on September 29, 2000), as amended.

"**Electricity Property**" refers to a municipal corporation's or municipal electricity utility's interest in real or personal property used in connection with generating, transmitting, distributing, or retailing electricity.

"**Electricity Retailer Code of Conduct**" refers to the Electricity Code of Conduct which was published by the OEB on August 18, 1999 and came into effect on February 29, 2000, as amended.

"**IEMO**" or "**IESO**" refers to the Independent Electricity Market Operator (now the Independent Electricity System Operator).

"Initial Note" refers to the promissory note dated July 1, 1999 in the principal amount of $947,000,000 issued by LDC to the City of Toronto in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. See note 11 to the Consolidated Financial Statements.

"ITA" refers to the *Income Tax Act (Canada).*

"kW" refers to a kilowatt, a common measure of electrical power equal to 1,000 Watts.

"kWh" refers to a kilowatt-hour, a standard unit for measuring electrical energy produced or consumed over time. One kWh is the amount of electricity consumed by ten 100 Watt light bulbs burning for one hour.

"LDC" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro-Electric System Limited.

"Low Volume Consumers" refers to a class of consumers of electricity who utilize less than 250,000 kWh annually.

"Management's Discussion and Analysis of Financial Condition and Results of Operations" refers to Management's Discussion and Analysis of Financial Condition and Results of Operations of the Corporation for the year ended December 31, 2006, a copy of which is included in this Annual Information Form as Annex B.

"Market Participants" refers to persons authorized to participate in the wholesale market for electricity administered by the IESO, including generators, transmitters, distributors, retailers and consumers.

"MBRR" refers to market-based rate of return.

"Minister" or **"Ministerial"** refers to the Province's Minister of Energy.

"MEU" refers to municipal electricity utility.

"MTN Program" refers to the medium term note program established by the Corporation in January 2006. See section 8.2 "Ratings".

"OEB" refers to the Ontario Energy Board.

"OMERS" refers to the Ontario Municipal Employees Retirement System, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario.

"OPA" refers to the Ontario Power Authority.

"OPG" refers to Ontario Power Generation Inc.

"Open Access" refers to the opening of Ontario's wholesale and retail electricity markets to competition pursuant to the requirement under the *Electricity Act, 1998* that transmitters and distributors of electricity in Ontario provide generators, retailers and consumers with non-discriminatory access to their transmission and distribution systems. Open Access commenced on May 1, 2002.

"PCBs" refers to polychlorinated biphenyls, a synthetic chemical compound consisting of chlorine, carbon and hydrogen. PCBs are used primarily as insulating and cooling elements in electrical equipment. Secondary uses include hydraulic and heat transfer fluids, flame proofing adhesives, paints, sealants and cable insulating paper.

"Performance Based Regulation" refers to a form of rate setting regulation which attempts to simulate the incentives and penalties of competition in certain circumstances, including natural monopolies, where actual competition is not practical. In general, Performance Based Regulation operates to limit rates or to cap prices while at the same time providing for minimum standards of customer service and system reliability, which discourage attempts to increase margins by reducing service.

"PILs" refers to the "Payment In Lieu of Corporate Taxes" regime contained in the *Electricity Act, 1998* pursuant to which municipal electricity utilities that are exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* are required to make, for each taxation year, payments in lieu of taxes to the Ontario Electricity Financial Corporation. See note 4(b) and note 17 to the Consolidated Financial Statements.

"Province" refers to the Government of the Province of Ontario.

"Rate Handbook" refers to the Electricity Distribution Rate Handbook issued by the OEB in March 2000, and outlining the regulatory framework that the OEB will use to administer electricity distribution rates in Ontario**.**

"2006 Rate Handbook" refers to the Electricity Distribution Rate Handbook issued by the OEB in May 2005 and containing filing requirements and guidelines and setting out how the OEB generally intends to address applications for 2006 electricity distribution rates.

"Rate of Return/Cost of Service Regulation" refers to a form of regulation under which the OEB determines a total allowed cost of service that a distributor may recover from customers through rates for a given rate year. The total allowed cost of service consists of approved distributor expenses, including operations, maintenance and administration, depreciation, and an allowance for income taxes, as well as an allowed rate of return on the equity and debt capital invested to finance the distributor. Distributor earnings are derived through the return component of the total cost of service, and no mark-up or discount is applied to other items of expense.

"Replacement Note" refers to the promissory note in the principal amount of $980,230,955 issued by LDC to the City of Toronto to replace the Initial Note effective January 1, 2000. The Replacement Note was transferred by the City of Toronto to the Corporation on May 7, 2003 in consideration for the issuance by the Corporation to the City of the City Note. See note 11 to the Consolidated Financial Statements. The Replacement Note was amended and restated effective May 1, 2006 to conform to certain changes made under the Amended and Restated City Note (as the context requires, "Replacement Note" refers to the amended and restated Replacement Note dated May 1, 2006).

"Retail Settlement Code" refers to the Retail Settlement Code which was published by the OEB on December 13, 2000 and became effective on the commencement of Open Access (except with respect to "Service Agreements", which came into effect on March 1, 2001), as amended.

"RPP" refers to the Regulated Price Plan created as a result of the *Electricity Restructuring Act, 2004*. The OEB has developed an RPP for residential, small business and certain other customers, which came into effect on April 1, 2005.

"S&P" refers to Standard & Poor's.

"Shareholder Direction" refers to the Shareholder Direction adopted by the Council of the City of Toronto with respect to the Corporation, as amended and restated from time to time, pursuant to which the City has set out certain corporate governance principles with respect to the Corporation.

"Smart Meter" refers to a metering device capable of recording and transmitting hourly consumption information of a residential or general service customer.

"Standard Supply" or "Standard Supply Service" refers to a distributor's obligation to sell electricity to Standard Supply Customers, or to give effect to such rates as determined by the OEB under section 79.16 of the *Ontario Energy Board Act*.

"Standard Supply Customers" refers to persons connected to a distributor's electricity distribution system who are not served by retailers or whose retailer is unable to sell them electricity or who request the distributor to sell electricity to them.

"Standard Supply Service Code" refers to the Standard Supply Service Code for Electricity Distributors which was published by the OEB in December 8, 1999 and became effective on the commencement of Open Access, as amended.

"Telecom" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro Telecom Inc.

"THC Revolving Credit Facility" refers to the $500 million revolving credit facility available to the Corporation. See note 9 to the Consolidated Financial Statements.

"TH Energy" refers to the Corporation's wholly-owned subsidiary, Toronto Hydro Energy Services Inc.

"Toronto Hydro" refers to the Corporation and its subsidiaries.

"TOU" refers to time-of-use.

"Transfer By-law" refers to By-law No. 374-1999 of the City of Toronto made under section 145 of the *Electricity Act, 1998* pursuant to which the Toronto Hydro-Electric Commission and the City transferred their assets and liabilities and employees in respect of the electricity distribution system to LDC and in respect of electricity generation, co-generation and energy services to TH Energy. See note 1 to the Consolidated Financial Statements. The Transfer By-law permits the Treasurer of the City of Toronto to adjust the fair market value of the assets and the consideration paid in respect of the electricity distribution assets transferred to LDC as a consequence of OEB rate orders and permitted rates of return for 2000 or any subsequent year.

"Watt" or **"W"** refers to a common measure of electrical power. One Watt equals the power used when one ampere of current flows through an electrical circuit with a potential of one volt.

"Watt Hour" refers to a measure of energy production or consumption equal to one Watt produced or consumed for one hour.

"WiFi" refers to the technology of wireless local access networks, which can be used for services such as the internet, voice over internet protocol, phone access and gaming.

Unless otherwise specified, all references to statutes are to statutes of the Province of Ontario and all references to dollars are to Canadian dollars.

PART 3 - CORPORATE STRUCTURE

3.1 Name, Address, Incorporation

On January 1, 1998, the former municipalities of Metropolitan Toronto, Toronto, East York, Etobicoke, North York, Scarborough and York amalgamated to form the City of Toronto. At the same time, the electric commissions of Toronto, East York, Etobicoke, North York, Scarborough and York were combined to form the Toronto Hydro-Electric Commission. Toronto Hydro is the successor to the Toronto Hydro-Electric Commission.

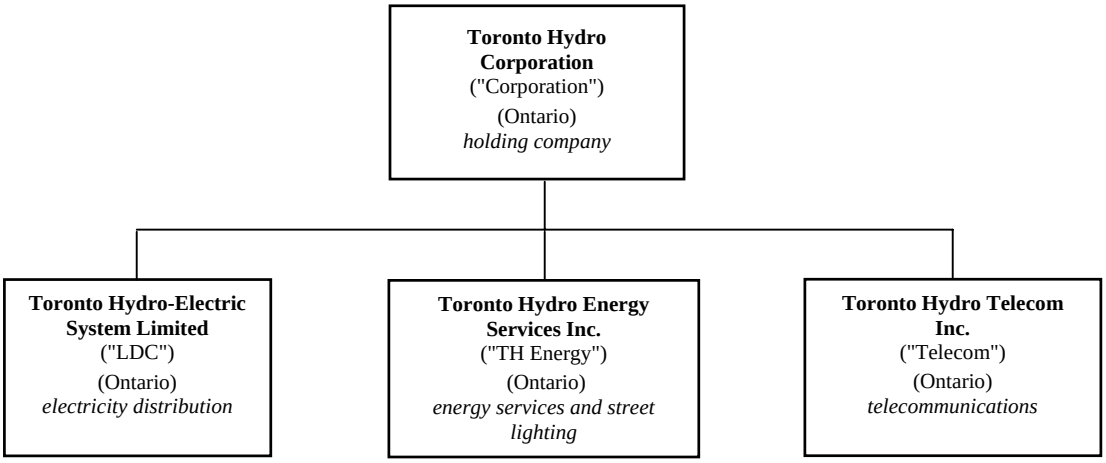
The Corporation, LDC and Toronto Hydro Energy Services Inc., were incorporated under the *Business Corporations Act* (Ontario) on June 23, 1999. Pursuant to the Transfer By-law, the Toronto Hydro-Electric Commission and the City of Toronto transferred their assets and liabilities in respect of the electricity distribution system to LDC and electricity generation, co-generation and energy services to TH Energy. See note 1 to the Consolidated Financial Statements.

Telecom was incorporated under the *Business Corporations Act* (Ontario) on September 26, 2000 and LDC transferred most of its fibre optic network to Telecom in October 2000.

The registered and head office of the Corporation is located at 14 Carlton Street, Toronto, Ontario M5B 1K5.

3.2 Intercorporate Relationships

The sole shareholder of the Corporation is the City of Toronto. The Corporation, in turn, owns 100% of the shares of the following principal subsidiaries, all of which were incorporated under the *Business Corporations Act* (Ontario):



PART 4 - BUSINESS OF TORONTO HYDRO

4.1 Toronto Hydro Corporation

The Corporation is a holding company which, through its wholly-owned subsidiaries:

- distributes electricity (LDC);
- provides street lighting and expressway lighting services, develops energy efficiency products and services, and operates generation assets (TH Energy); and
- provides fibre optic cable capacity and manages data communication services (Telecom).

The Corporation supervises the operations of, and provides corporate and management services and strategic direction to, its subsidiaries.

4.2 Toronto Hydro-Electric System Limited

LDC owns and operates $1.6 billion of Capital Assets comprised primarily of an electricity distribution system, which delivers electricity to approximately 678,000 customers located in the City of Toronto. LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in Ontario.

(a) LDC Distribution System

Electricity produced at generating stations is transmitted along transmission lines owned by Hydro One Inc. to terminal stations at which point the voltage is then reduced (or stepped down) to distribution-level voltages. Distribution voltages are then distributed across LDC's distribution system to distribution class transformers at which point the voltage is further reduced (or stepped down) for supply to end customers. Electricity typically passes through a meter before reaching a distribution board or service panel that directs the electricity to end use circuits.

LDC's distribution system is serviced from 35 terminal stations and is comprised of over 26,000 primary switches, 66,000 distribution transformers, 195 municipal substations, over 9,100 kilometres of overhead wires supported by over 159,000 poles and over 7,600 kilometres of underground wires.

(i) *Control Centre*

LDC has one control centre which operates four control districts. The control centre co-ordinates and monitors the distribution of electricity in the control districts, and provides isolation and work protection for internal staff and external customers. The control districts are linked to the distribution system by a voice and data communications network. The LDC utilizes supervisory control and data acquisition (SCADA) systems to monitor and operate the distribution system. LDC is completing the integration of its two SCADA systems into one master system. LDC recently installed a Distribution Management System to facilitate work process harmonization, centralized monitoring, remote sectionalizing, and isolation or restoration of primary voltage circuits.

(ii) *Terminal Stations*

LDC receives electricity at 35 terminal stations at which the voltage is stepped down to distribution voltages. The terminal stations contain power transformers and high-voltage switching equipment that are owned by Hydro One, with the exception of Cavanagh station that is fully owned by LDC. Terminal stations also contain low-voltage equipment such as circuit breakers, switches, and station bus work that are typically owned by LDC.

(iii) *Distribution Transformers and Municipal Substations*

Distribution voltage electricity is distributed from the terminal stations to distribution transformers which are typically located in buildings or vaults or mounted on poles or surface pads and are used to reduce or step down voltages to utilization levels for supply to customers. The distribution system includes over 66,000 distribution transformers. The distribution system also includes 195 municipal substations that are located in various parts of the City of Toronto and are used to reduce or step down electricity voltage prior to delivery to distribution transformers. LDC also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

(iv) *Wires*

LDC distributes electricity through a network of over 9,100 kilometres of overhead wires supported by over 159,000 poles and over 7,600 kilometres of underground wires installed in self-contained duct systems, which generally include extra ducts to accommodate future needs.

(v) *Meters*

LDC provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. LDC owns the meters and is responsible for their maintenance and accuracy.

(vi) *Reliability of Distribution System*

The table below sets forth certain industry recognized measurements of system reliability with respect to LDC's distribution system and the composite measures reported by the Canadian Electricity Association[4] for the twelve-month period ended December 31, 2005.

	LDC	**Canadian Electricity Association**
SAIDI [1]	1.21	4.80
SAIFI [2]	1.81	2.13
CAIDI [3]	0.67	2.26

Notes:

(1) SAIDI means System Average Interruption Duration Index and is a measure (in hours) of the annual system average interruption duration for customers served. SAIDI represents the quotient obtained by dividing the total customer hours of interruptions longer than one minute by the number of customers served.

(2) SAIFI means System Average Interruption Frequency Index and is a measure of the frequency of service interruptions for customers served. SAIFI represents the quotient obtained by dividing the total number of customer interruptions longer than one minute by the number of customers served.

(3) CAIDI means Customer Average Interruption Duration Index and is a measure (in hours) of the average duration of interruptions experienced by customers. CAIDI represents the quotient obtained by dividing SAIDI by SAIFI.

(4) Based on the 2005 Service Continuity Report, issued by the Canadian Electricity Association on October 24, 2006, which compiled data from 20 Canadian utilities.

(b) LDC Service Area and Customers

LDC serves approximately 678,000 customers located in the City of Toronto. The City of Toronto is the largest city in Canada with a population of approximately 2.5 million. The City of Toronto is a financial centre with large and diversified service and industrial sectors.

The table below sets out LDC's customer classes and certain operating data with respect to each class for each of the years in the two-year period ended December 31, 2006:

	Year ended December 31, 2006	
	2006	**2005**
Residential Service (1)		
Number of customers (as at December 31)	599,080	597,469
kWh (thousands)	5,351,747	5,724,299
Revenue (thousands)	563,734	674,471
% of total service revenue	25.1%	25.1%
General Service (2)		
Number of customers (as at December 31)	78,978	79,163
kWh (thousands)	17,583,280	18,084,770
Revenue (thousands)	1,484,919	1,784,244
% of total service revenue	66.2%	66.4%
Large Users (3)		
Number of customers (as at December 31)	49	47
kWh (thousands)	2,592,278	2,563,100
Revenue (thousands)	194,340	228,035
% of total service revenue	8.7%	8.5%
Total		
Number of customers (as at December 31)	678,107	676,679
kWh (thousands)	25,527,305	26,372,169
Revenue (thousands)	2,242,993	2,686,751

Notes:

(1) "Residential Service" means a service that is for domestic or household purposes, including single family or individually metered multi-family units and seasonal occupancy.

(2) "General Service" means a service supplied to premises other than those receiving "Residential Service" and "Large Users" and typically includes small businesses and "bulk-metered" multi-unit residential establishments.

(3) "Large Users" means a service provided to a customer with a monthly peak demand of 5,000 kW or more averaged over a twelve-month period.

(c) LDC's Real Property

The following table sets forth summary information with respect to the principal real property owned, leased or otherwise used by LDC:

Property	Total	Owned	Leased	Other [1]
Terminal stations [1]	35 sites	8	0	27
Municipal substations[1]	195 sites	178	4	13
Control centre	1 site	1	0	0
Operations centres[2]	6 sites	5	1	0

Note:

(1) Certain terminal stations and municipal substations are located on lands owned by the Province, the City of Toronto and others. Where distribution lines cross over and run parallel with lands owned by railway companies, appropriate access rights, generally referred to as crossing agreements, have been obtained from the railway companies. Toronto Hydro also owns the real property on which are located 40 municipal substations that are currently classified as decommissioned.

(2) Toronto Hydro owns, leases or operates out of 6 centres which accommodate office, staff, crews, vehicles, equipment and material necessary to operate and monitor the electricity distribution and telecom systems.

Under the *Ontario Energy Board Act, 1998*, electricity distributors are entitled to apply to the OEB for authority to expropriate land required in connection with new or expanded electricity distribution lines or interconnections. If, after a hearing, the OEB is of the opinion that the expropriation of land is in the public interest, the OEB may make an order authorizing expropriation upon payment of specified compensation. The *Electricity Act, 1998* grandfathers thousands of existing unregistered easements, principally for distribution over third party lands. The *Electricity Act, 1998* also authorizes electricity distributors to locate assets on, over or under public streets and highways.

(d) Regulation of LDC

The business of LDC is regulated by the OEB, which has broad powers relating to licensing and standards of conduct and service and the regulation of rates charged by LDC and other electricity distributors.

(i) *Distribution Licence*

On April 1, 1999, the OEB issued a transitional distribution licence to the Toronto Hydro-Electric Commission. The licence was transferred to LDC in July 1999 and subsequently extended by the OEB to December 31, 2003. On October 17, 2003, the licence was renewed by the OEB. The term of the current licence is until October 16, 2023. The licence allows LDC to own and operate an electricity distribution system in the City of Toronto. Among other things, the licence provides that LDC may not carry on any business activity, other than the distribution of electricity, except through affiliated companies, may not impose charges for the distribution of electricity except in accordance with distribution rate orders approved by the OEB, and must comply with industry codes established by the OEB. In addition to the distribution of electricity, under the terms of the *Electricity Restructuring Act, 2004* electricity distributors are also permitted to provide additional services related to the promotion of energy conservation, demand management and alternative, clean and renewable sources of energy.

See Annex C – Regulation of Ontario's Electricity Industry as it relates to Toronto Hydro for a more detailed description of the terms of LDC's distribution licence.

(ii) *Industry Codes*

The OEB has established the following codes that prescribe minimum standards of conduct and service for LDC and other distributors.

- *Affiliate Relationships Code.* The Affiliate Relationships Code establishes standards and conditions for the interaction between distributors and their affiliated companies. These standards and conditions are intended to minimize the potential for a distributor to cross-subsidize competitive or non-monopoly activities, to protect the confidentiality of consumer information,

and to ensure that there is no preferential access to regulated services. The Affiliate Relationships Code also prohibits a distributor from making investments in or providing financial assistance to its affiliates (e.g, TH Energy and Telecom in the case of LDC) in excess of 25% of the distributor's total equity.

- *Distribution System Code.* The Distribution System Code establishes the minimum conditions that a distributor must meet in carrying out its obligations to distribute electricity, including standards of service relating to customer connections, expansions and new facilities.

- *Retail Settlement Code.* The Retail Settlement Code outlines the obligations of a distributor with respect to its relationship with retail Market Participants and its role as a retail market settlement administrator.

- *Standard Supply Service Code.* The Standard Supply Service Code requires a distributor to provide standard supply service to its Standard Supply Customers.

The codes and the other regulatory instruments applicable to LDC are described in more detail under Annex C - Regulation of Ontario's Electricity Industry as it relates to Toronto Hydro.

(iii) *Distribution Rates*

The OEB is responsible for regulating the distribution rates charged by LDC and other electricity distributors.

Initial rates for LDC became effective on December 1, 2000 according to the OEB-approved methodology based on 1999 actual cost levels adjusted for the first instalment of the MBRR. The second instalment of the MBRR was permitted in rates effective March 1, 2002. The third instalment of the market adjusted revenue requirement to achieve the full MBRR was permitted in rates effective April 1, 2005, subject to a commitment by LDC to invest these funds in CDM projects. See note 3 to the Consolidated Financial Statements.

In 2004, the OEB undertook a Rate of Return/Cost of Service Regulation review for the purpose of establishing 2006 rates for distributors. A Rate of Return/Cost of Service Regulation approach involves a detailed assessment of a distributor's cost levels in all applicable functional areas in order to establish the overall cost of service to be recovered from consumers through revised distribution rates.

To facilitate the processing of approximately 90 distributor rate applications, the OEB issued the 2006 Rate Handbook on May 11, 2005. The 2006 Rate Handbook, which superseded the Rate Handbook, was composed of filing requirements and guidelines, and set out how the OEB generally intended to address applications for 2006 electricity distribution rates.

On April 12, 2006, the OEB approved a decrease in the distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $58.0 million. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt (including the debt outstanding under the Replacement Note) from 6.8% to 5% per annum.

On December 20, 2006, the OEB issued a 2007 rate adjustment model and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. Base distribution rates (exclusive of rate riders for the recovery of regulatory assets and other items) will be adjusted formulaically to reflect an allowance for inflation of approximately 1.8% subject to final determination by the OEB, a fixed productivity offset of 1.0%, and removal of the Federal Large Corporation Tax, for a net effect of approximately 0.4%.

LDC filed its 2007 rate application in accordance with the guidelines on January 26, 2007.

See Annex C – Regulation of Ontario’s Electricity Industry as it Relates to Toronto Hydro for a more detailed discussion of LDC’s distribution rates and rate applications.

(iv) *Regulatory Assets*

Prior to March 2005, electricity distributors were required to reflect certain prescribed costs on their balance sheets. See note 7 to the Consolidated Financial Statements for a description of these costs. On March 31, 2005, the OEB ordered that approved regulatory asset balances be aggregated into a single account which will be recovered by electricity distributors over a three-year period ending March 31, 2008. See note 7 to the Consolidated Financial Statements.

See Annex C – Regulation of Ontario's Electricity Industry as it Relates to Toronto Hydro for a more detailed discussion with respect to regulatory assets.

(v) *PILs*

The Corporation and its subsidiaries are exempt from tax under the ITA, if not less than 90% of the capital of the Corporation is owned by the City of Toronto and not more than 10% of the income of the Corporation and each of its subsidiaries is derived from activities carried on outside the municipal geographical boundaries of the City of Toronto.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the *Electricity Act, 1998*. The *Electricity Act, 1998* provides that a MEU that is exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* is required to make, for each taxation year, a payment in lieu of corporate taxes to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

Since October 1, 2001, the Corporation has been required to make payments under the PILs regime. The 2006 Rate Handbook issued by the OEB contemplates distribution rate adjustments to permit recoveries relating to PILs. See note 4 (b) and note 17 to the Consolidated Financial Statements.

See Part 6 – Impact of Payment in Lieu of Taxes

(vi) *Transfer Tax*

Transfers of Electricity Property made to a municipal corporation, a municipal electricity utility, Hydro One Inc., or Ontario Power Generation Inc. will be exempt from the transfer tax if made after October 16, 2006 and before October 17, 2008. In addition, a draft regulation has been proposed which would allow a refund of transfer tax where it had been paid on the sale or transfer of Electricity Property and where the proceeds of that transfer were reinvested in other eligible property after October 16, 2006 and before the end of the second taxation year following the taxation year in which the liability to pay the transfer tax arose.

(e) Environmental Matters

LDC is subject to extensive Canadian federal, provincial and local regulation relating to the protection of the environment. The principal federal legislation is the *Canadian Environmental Protection Act, 1999* which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances. The principal provincial legislation is the *Environmental Protection Act*, which regulates releases and spills of contaminants, including PCBs and ozone-depleting substances, and waste management. Municipal by-laws regulate discharges of industrial sewage and storm water run-off to the municipal sewer system. In addition, both the provincial and federal governments have environmental assessment legislation which is designed to foster better planning and the identification and mitigation of potential environmental impacts of projects or undertakings prior to their commencement.

(i) *Environmental Management System and Environmental Policy*

LDC has environmental programs designed to identify and manage environmental impacts and to aid in the continual improvement of environmental performance. Toronto Hydro has adopted an Environmental Policy to assist it in identifying and addressing the environmental impacts associated with its principal business, which is the distribution of electricity by LDC. The Environmental Policy is reviewed and updated periodically by the Environment, Health and Safety Committee of the Board of Directors.

(ii) *Environmental Permits, Licences and Approvals*

LDC is required under federal, provincial and municipal environmental legislation to obtain and maintain specified environmental permits and approvals. These permits and approvals relate to, among other things, waste disposal, discharges to water and impacts on aquatic habitat at river and stream crossings. The Corporation and LDC have all material environmental permits and approvals required to be obtained and maintained by them.

(iii) *Releases and Land Remediation*

Federal, provincial and municipal environmental legislation regulates the release of substances into the environment through the prohibition of discharges that have an adverse effect or a potentially adverse effect on the environment. Spills and leaks of substances occur in the normal course of LDC's operations, which could result in fines or clean-up costs being incurred in connection with these releases. LDC has an emergency response capability designed to respond to spills in a timely manner, to minimize the environmental impact of spills, and to comply with its legal obligations. LDC has voluntarily, from time to time, assessed and remediated sites for potential contamination (including PCBs). It is possible that additional costs could be incurred due to potential contamination at sites.

(iv) *Hazardous Substances*

LDC manages a number of hazardous substances (including PCBs). During 2006, LDC sent approximately 65 tonnes of stored PCB waste for destruction. LDC continues to operate PCB-containing equipment which is expected to generate approximately 402 tonnes of waste when removed. PCB-containing equipment (other than in-service cables which are tested and treated after they are no longer in service) has been identified and is in the process of being phased out as part of a program that is expected to be completed by 2009 in accordance with new federal regulations governing the phase-out and destruction of PCB-containing equipment, which became effective in 2007. These regulations require the phase-out and destruction of PCB-containing equipment by, depending on the PCB levels, December 31, 2009 or December 31, 2014.

4.3 Toronto Hydro Energy Services Inc.

TH Energy provides street lighting and expressway lighting services, develops energy efficiency products and services, and operates generation assets.

4.4 Toronto Hydro Telecom Inc.

Telecom is a provider of "dark" fibre optic capacity and data communications services to telecommunications carriers, business customers and large institutions in the City of Toronto. Telecom owns $27.7 million of Capital Assets comprised primarily of a network of fibre optic cables located in ducts, on poles and in other parts of the electricity distribution system of LDC. The network is currently connected to 490 buildings located in the City of Toronto.

Telecom leases "dark" fibre optic cable capacity to customers which "light" the fibre using their own technology. The leases typically range from one to five years in length and provide for monthly payments and one-time connection fees. Construction of the network began in 1995. Most of the fibre optic cables were supplied and installed by a third party contractor.

Telecom also provides a portfolio of managed data services that includes private line access, Ethernet services, dedicated Internet access and data centre co-location services. These services are delivered over Telecom's fibre optic network and are managed by Telecom's network operations centre. No material capital costs are incurred by Telecom until such services are under contract.

In 2006, Telecom utilized excess network and fibre capacity to build a WiFi network, called One Zone, which covers the downtown core of Toronto with wireless internet access. This wireless network uses specialized transmitters, placed on street lights, to provide outdoor wireless service coverage.

Telecom is a "telecommunications common carrier" as defined by the *Telecommunications Act* (Canada), and as such is regulated by the CRTC. Telecom is registered with the CRTC as a Non-dominant, Facilities-Based Carrier.

4.5 Other Operations

1455948 Ontario Inc. is a wholly-owned subsidiary of the Corporation. 1455948 Ontario Inc. and a wholly-owned subsidiary of OPG are equal partners in EBT Express. EBT Express owns 67% of the shares in The SPi Group Inc. Screaming Solutions Ventures Inc. is the other shareholder of The SPi Group Inc. The SPi Group Inc. is an e-commerce venture which was formed to provide, among other things, centralized electronic data management and transaction services to energy industry participants.

In 2006, TH Energy Services ceased its managing activities with respect to a portfolio of electricity contracts (the last of which expired on December 31, 2006). See note 15 to the Consolidated Financial Statements.

On February 8, 2007, TH Energy Services sold the assets comprising its water heater business. See note 23 and 26 to the Consolidated Financial Statements.

4.6 Other Information

(a) Employees

At December 31, 2006 Toronto Hydro had 1,673 employees, of whom 1,343 were employed by LDC. 1,236 employees are members of bargaining units represented by the Canadian Union of Public Employees, Local One (CUPE One), of which 1,157 were employed by LDC. In addition, 25 engineers are represented by the Society of Energy Professionals.

On December 20, 2005, CUPE One ratified collective agreements governing inside and outside employees for a three-year period expiring January 31, 2009. The collective agreements implemented an immediate wage increase of 3.5% on rates in effect on December 16, 2005 and provide for general wage increases of 3.25%, effective February 1, 2007 and 2008 on rates in effect on January 31, 2007 and 2008, respectively. The collective agreements also contain cost of living escalator clauses which provide for wage adjustments corresponding to the percentage change in the Consumer Price Index. The escalator clauses will not become effective unless certain prescribed thresholds are exceeded.

On July 1 2006, the Society of Energy Professionals ratified a new collective agreement for a one-year period expiring June 2007. The collective agreement implemented wage increases of 3.5% on July 1, 2006.

Full time employees of Toronto Hydro participate in OMERS, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Plan benefits are determined on a formula based on the highest average contributory earnings and years of service with an offset for Canada Pension Plan benefits and are indexed to increases in the Consumer Price Index, subject to an annual maximum of 6%. Any increase in the Consumer Price Index above 6% per year is carried forward for later years. Both participating employers and participating employees are required to make plan contributions based on participating employees' contributory earnings. Because of a surplus, a plan contribution holiday was in effect from August 1998 until December 2002. Contributions recommenced in January 2003. See note 4(j) and note 12 to the Consolidated Financial Statements.

In addition to OMERS, Toronto Hydro provides other retirement and post-employment benefits to employees, including medical and life insurance benefits. See note 4(j) and note 12 to the Consolidated Financial Statements.

(b) Health and Safety

Toronto Hydro has established and maintains key safety priorities including safe work practices, accident investigation and safety performance management. LDC has reduced lost time accident frequencies from 5.5 per 200,000 hours worked in 1998 to 0.65 per 200,000 hours worked in 2006.

(c) Insurance

Toronto Hydro's current insurance policies provide coverage for a variety of losses and expenses which might arise from time to time, including comprehensive general liability, all risk property and boiler and machinery insurance, covering loss or damage on certain physical assets, liabilities of directors and officers and automobile liability. The

Corporation believes that the coverages, amounts and terms of its insurance arrangements are consistent with prudent Canadian industry practice.

PART 5 - RELATIONSHIP WITH THE CITY OF TORONTO

5.1 Shareholder Direction

As sole shareholder of the Corporation, the City has adopted the Shareholder Direction which sets out the following corporate governance principles with respect to Toronto Hydro:

- the objectives of the City in connection with its relationship with Toronto Hydro;
- the principles that govern the operations of Toronto Hydro;
- the matters in addition to those set out in the *Business Corporations Act (Ontario)* that require the approval of the City as the sole shareholder of Toronto Hydro; and
- certain financial and administrative arrangements between the Corporation and the City.

(a) Objectives

The City's objectives in connection with its relationship with Toronto Hydro are as follows:

- the value of Toronto Hydro should be maintained or increased;
- the City's income stream from Toronto Hydro should be comparable to the City's estimated financial benefit if Toronto Hydro had been sold as a going concern;
- Toronto Hydro's consumers should not be unduly impacted by the transfer of assets from the City and the Toronto Hydro-Electric Commission to Toronto Hydro; and
- the environmental impacts related to Toronto Hydro should be improved.

(b) Principles Governing Operations

The Shareholder Direction states that the business of Toronto Hydro is integral to the well-being and the infrastructure of the City of Toronto and provides, among other things, that it is in the best interests of Toronto Hydro and the stakeholders affected by its business that Toronto Hydro conduct its affairs:

- on a commercially prudent basis, in a manner consistent with the energy policies established by the City from time to time and in accordance with the financial performance objectives of the City;
- to provide a reliable and efficient electricity distribution system, with an emphasis on customer satisfaction;
- in a safe and environmentally responsible manner; and
- in a manner that promotes energy conservation and environmental responsibility and protects and enhances the City's urban forest.

The Shareholder Direction provides that the Corporation's board of directors is responsible for determining and implementing the appropriate balance among these principles.

(c) Shareholder Approval

In addition to those matters set out in the *Business Corporations Act (Ontario)*, the following matters, among others, require the approval of the City as the sole shareholder of the Corporation:

- creating any indebtedness ranking senior to the City Note while the City Note is held by the City;
- subject to certain exceptions in the case of LDC, creating any security over the assets of the Corporation or LDC;
- in the case of LDC, providing any financial assistance to any person other than in accordance with the Shareholder Direction;
- in the case of the Corporation and LDC, making any investment in or providing any financial assistance to any subsidiary of the Corporation (other than LDC), other than trade payables incurred in the ordinary course of business on customary terms and an investment in or financial assistance to a subsidiary that originally was an investment in or financial assistance to LDC, in excess of 12% of the shareholder's equity of LDC as shown in its most recent financial statements; and
- acquiring any interest in the distribution system, undertaking or securities of a distributor operating outside the City of Toronto unless, among other things, the acquisition does not adversely affect the dividend payable to the City and there is no dilution of the City's shareholding in the Corporation.

The City has authorized the Corporation to provide financial assistance to its subsidiaries, in the form of letters of credit and guarantees, for the purposes of enabling them to carry on their respective businesses if the aggregate amount of the financial assistance does not exceed $500 million. See note 16 to the Consolidated Financial Statements.

(d) Financial Performance

The Shareholder Direction provides that the Corporation's board of directors will use its best efforts to ensure that Toronto Hydro meets certain financial performance standards, including those relating to credit rating and dividends.

(e) Credit Rating

The Shareholder Direction provides that the Corporation will obtain and maintain a rating of A minus or higher as defined by S&P on its senior debt securities.

(f) Dividends

Subject to applicable law, the Shareholder Direction provides that the Corporation will pay dividends to the City each year equal to the greater of $25 million or 50% of consolidated net income for the year. The dividends are not cumulative and are payable as follows:

- $6 million on the last business day of each of the first three fiscal quarters during the year;
- $7 million on the last business day of the fiscal year; and
- the amount (if any) by which 50% of consolidated net income for the year exceeds $25 million, within ten days after the board of directors of the Corporation approves the Corporation's consolidated financial statements for the year.

The Corporation declared and paid dividends to the City amounting to $49.2 million in 2004, $68.0 million in 2005, and $46.2 million in 2006. See note 18 and note 26 to the Consolidated Financial Statements.

(g) Administrative Arrangements

The Corporation is required to provide the City with annual updates of its business plan and copies of its quarterly and annual financial reports.

5.2 Indebtedness to the City of Toronto

As part of the consideration for the transfer by the Toronto Hydro-Electric Commission and the City of Toronto of their assets and liabilities in respect of the electricity distribution system to LDC in July 1999, LDC issued the Initial Note to the City.

The Replacement Note was issued to replace the Initial Note effective January 1, 2000. The principal amount of the Replacement Note was increased from $947,000,000 to $980,230,955 and the interest rate under the Replacement Note was increased from 6.0% to 6.8% as authorized under the Transfer By-law to reflect certain changes made by the OEB to the permitted cost of debt for purposes of setting distribution rates. See note 11 to the Consolidated Financial Statements.

On May 7, 2003, the City of Toronto transferred to the Corporation the Replacement Note in consideration for the issue by the Corporation to the City of the City Note in the same principal amount. See note 11 to the Consolidated Financial Statements.

On September 5, 2006, the Corporation announced that it had agreed to amend and restate the City Note effective May 1, 2006. The Amended and Restated City Note fixed the interest rate at 6.11% and established an agreed repayment schedule: ($245,058,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and on May 6, 2013). Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year. See note 11 to the Consolidated Financial Statements.

The Amended and Restated City Note contains covenants and events of default which are similar to those provided for under the terms of the Debentures. Upon the occurrence of an event of default under the Amended and Restated City Note, the City may declare the principal amount of the Amended and Restated City Note, together with accrued and unpaid interest thereon, to be immediately due and payable.

The Amended and Restated City Note is also:

- convertible in whole or in part at any time and from time to time into debt securities issued by the Corporation or any of its subsidiaries (subject to applicable law and compliance by the Corporation with covenants contained in its outstanding indebtedness); and

- assignable in whole or in part at any time and from time to time without the consent of the Corporation.

The Amended and Restated City Note is a direct unsecured obligation of the Corporation and ranks equally with all other unsecured and unsubordinated indebtedness of the Corporation, including the Debentures and the THC Revolving Credit Facility.

5.3 Services Provided to the City of Toronto

Toronto Hydro provides certain services to the City of Toronto at commercial rates, including consolidated electricity billing services and street lighting and expressway lighting services. In addition, the City of Toronto and its agencies have entered into energy efficiency service contracts with TH Energy and CDM contracts with LDC. See note 16 and note 19 to the Consolidated Financial Statements.

PART 6 - IMPACT OF PAYMENTS IN LIEU OF TAXES

The Corporation is generally exempt from tax under the ITA if not less than 90% of its capital is owned by the City of Toronto and not more than 10% of its income is derived from activities carried on outside the municipal geographical boundaries of the City of Toronto. In addition, the Corporation's subsidiaries are also generally exempt from tax under the ITA provided that all of their capital is owned by the Corporation and not more than 10% of their respective incomes is from activities carried on outside the municipal geographical boundaries of the City of Toronto. A corporation exempt from tax under the ITA is also generally exempt from tax under the *Corporations Tax Act (Ontario)*.

The Corporation and each of its subsidiaries are MEUs for purposes of the PILs regime contained in the *Electricity Act, 1998*. The *Electricity Act, 1998* provides that a municipal electricity utility that is exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* is required to make, for each taxation year, a PILs to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the *Corporations Tax Act (Ontario)* if it were not exempt. The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining their respective liabilities for PILs.

If the Corporation or a subsidiary ceased to be exempt from tax under the ITA and the *Corporations Tax Act (Ontario)*, it would become subject to tax under those statutes and would no longer be required to make PILs to the Ontario Electricity Financial Corporation and would generally be deemed to have disposed of its assets for proceeds of disposition equal to their fair market value at that time and to have reacquired its assets at the same amount with the result that:

- such corporation would become liable to make PILs in respect of any income or gains arising as a result of these deemed dispositions; and

- the amount of annual taxes payable by the corporation under the ITA and the *Corporations Tax Act (Ontario)* may be different from the PILs that would be payable without a loss of tax-exempt status to reflect, among other things, the consequences of these deemed dispositions and acquisitions.

The *Electricity Act, 1998* also provides that a municipal corporation or municipal electricity utility is required to pay a transfer tax before it transfers Electricity Property. An interest in Electricity Property includes any interest in a corporation, partnership or other entity that derives its value in whole or in part from Electricity Property. The transfer tax is generally the prescribed percentage (currently 33%) of the fair market value of the interest transferred. The amount of transfer tax payable where the interest that is transferred is an interest in a corporation, partnership or other entity is calculated in accordance with a special rule. The amount of transfer tax payable by a municipal electricity utility on a transfer of Electricity Property may be reduced by:

- any PILs made by the municipal electricity utility in respect of the part of the taxation year to and including the date that the transfer takes place or a previous taxation year;

- any amount that the municipal electricity utility has paid as tax under Parts II, II.1 or III of the *Corporations Tax Act (Ontario)* in respect of the part of the taxation year to and including the date that the transfer takes place or a previous taxation year; and

- the tax for which the municipal electricity utility would be liable under Part I of the ITA if the municipal electricity utility had no income for the taxation year other than the capital gain or income in respect of the disposition of eligible capital property arising on the transfer of the property subject to the transfer tax.

PILs are deductible in computing the transfer tax only to the extent that they have not been previously applied to reduce transfer tax payable by a municipal corporation or a municipal electricity utility.

The Rate Handbook and the 2006 Rate Handbook contemplated distribution rate adjustments to permit recoveries relating to PILs. The permitted recoveries relating to PILs for 2002 were used by the OEB for purposes of permitted recoveries relating to PILs for 2004 and part of 2005. The permitted recoveries relating to PILs for the thirteen-month period beginning April 1, 2005 were recalculated in the 2005 rate application model to include the effects of changes in tax rates and the third instalment of the market-based Rate of Return. The permitted recoveries relating to PILs for the twelve-month period beginning May 1, 2006 were recalculated in the 2006 electricity distribution rate application. See note 4(b) and note 17 to the Consolidated Financial Statements.

PART 7 - RISK FACTORS

Toronto Hydro's business is subject to a variety of risks including those described below:

7.1 Regulatory Uncertainty

The OEB regularly conducts consultations with interested stakeholders with respect to a number of areas which may affect electricity distributors. See Annex C - Regulation of Ontario's Electricity Industry as it Relates to Toronto Hydro for further details.

The continuing restructuring of Ontario's electricity industry and other regulatory developments may affect the distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation. In particular, there can be no assurance that:

- the OEB may not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through distribution rates;
- the OEB will not permit competitors to provide distribution services in a distributor's licensed area;
- the OEB will allow recovery for revenue lost as a consequence of the emergence and adoption of new technologies such as distributed generation, or unanticipated effects of conservation and demand management;
- parts of LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Changes to any of the laws, rules, regulations or policies applicable to the businesses carried on by Toronto Hydro could have a significant impact on Toronto Hydro. There can be no assurance that Toronto Hydro will be able to comply with applicable future laws, rules, regulations and policies. Failure by Toronto Hydro to comply with applicable laws, rules, regulations and policies may subject Toronto Hydro to civil or regulatory proceedings which may have a material adverse effect on Toronto Hydro.

7.2 Condition of Distribution Assets

Toronto Hydro's ability to continue to maintain and operate the distribution system reliably and safely in the future will depend on, among other things, the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

7.3 Electricity Consumption

LDC's distribution rates typically comprise a fixed charge and a usage-based (consumption charge). The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

7.4 Credit Rating

Should the Corporation's credit rating from both credit rating agencies fall to below A – (S&P) and A-low (DBRS), the Corporation and its subsidiary companies may be required to post additional collateral with counterparties as part of its normal course of operations in the Ontario electricity spot market, and will be subject to additional reporting requirements under the terms of its short-term credit agreement.

7.5 Additional Debt Financing

The Corporation expects to borrow to repay the Amended and Restated City Note when required to do so under the terms of the Amended and Restated City Note. The Corporation's ability to arrange sufficient and cost-effective debt financing to repay the Amended and Restated City Note and for general corporate purposes (including credit support for prudential requirements) could be adversely affected by a number of factors, including the regulatory environment in Ontario, the Corporation's results of operations and financial condition, financial market conditions, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities, and general economic conditions.

7.6 Credit Risk

Toronto Hydro is subject to credit risk with respect to customer non-payment. LDC is permitted to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (including letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection. See Annex C - Regulation of Ontario's Electricity Industry as it Relates to Toronto Hydro for further details.

In the event of an actual payment default and attendant bad debt expense incurred by LDC, roughly 80 percent of the expense would be related to commodity and transmission costs, and the remainder to LDC's distribution revenue. Accordingly, while LDC will be liable for the full amount of the default, there can be no assurance that the OEB will allow recovery of the bad debt expense from remaining customers. Rather, it is expected that the OEB will examine LDC's application for claiming bad debt expenses on a case-by-case basis.

7.7 LDC Competition

In the past, there had been one electricity distributor in each region of Ontario. Under the current regulatory regime, a person must obtain a licence from the OEB in order to own and operate a distribution system. LDC has the right to distribute electricity in the City of Toronto. Although the distribution licence does specify the area in which the distributor is authorized to distribute electricity, unless otherwise provided, the licence does not provide exclusive distribution rights for such area.

The Corporation believes that the complexities and potential inefficiencies that would be created by having multiple electricity distributors authorized to serve a single area are likely to result in the continuation of the practice of having a single electricity distributor authorized to serve a single area. In addition, the Corporation believes that there are significant barriers to entry with respect to the business of electricity distribution in Ontario, including the cost of maintaining a distribution system, OEB regulation of distribution rates and the level of regulatory compliance required to operate a distribution system. However, the Corporation recognizes that more than one distribution licence could be issued for the same area and there is a possibility that in the future some business functions or activities could be separated from LDC and made open to competition from non-regulated business entities.

7.8 Environmental Regulation

Toronto Hydro is subject to Canadian federal, provincial and municipal environmental regulation. Failure to comply with environmental regulation could subject Toronto Hydro to fines and other penalties. In addition, releases of hazardous substances now or in the past on or from properties owned, leased, occupied or used by Toronto Hydro or the Toronto Hydro-Electric Commission, or as a result of Toronto Hydro's operations or those of the Toronto Hydro-Electric Commission, could lead to governmental orders requiring investigation, control and/or remediation of releases. The presence or release of hazardous substances could also lead to claims by third parties for harm as a result of the existence of these substances.

Changes in environmental regulation or enforcement may impose material additional costs on Toronto Hydro. In addition, new approvals or permits or renewals of existing approvals and permits may require environmental assessment and/or result in the imposition of conditions which may result in significant compliance costs. The process for obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive.

7.9 Labour Relations

Toronto Hydro's ability to operate successfully in the restructured electricity industry in Ontario will depend in part on its ability to make changes to existing work practices and procedures to adapt to changing circumstances. Toronto Hydro's ability to make these changes will depend in part on its ability to develop plans and approaches that are acceptable to its labour unions. There can be no assurance that Toronto Hydro will be able to secure the support of its labour unions in this regard.

7.10 Work Force Renewal

Over the next eight years, more than 350 employees will be eligible for retirement. This number represents approximately 25% of LDC's workforce (with a significant number of potential retirements occurring in trade and technical positions). Accordingly, LDC will be required to attract and retain skilled employees. There can be no assurance that LDC will be able to attract and retain the required workforce.

7.11 Conflicts of Interest and Change of Ownership

The City of Toronto owns all of the outstanding shares of the Corporation and has the power to determine the composition of the board of directors of the Corporation and influence Toronto Hydro's major business and corporate decisions, including its financing programs and dividend payments. A conflict may arise between the City's role as the sole shareholder and major debt holder of the Corporation and its role as the administrator of the City budget and other matters for the residents of the City of Toronto. The City of Toronto may decide to sell all or part of Toronto Hydro. In this event, depending on the nature of the transaction, the Corporation's credit ratings may be negatively affected.

7.12 Real Property Rights

Certain terminal stations and municipal substations of LDC are located on lands owned by the Province, the City of Toronto and others. In some cases, LDC does not have and may not be able to obtain formal access agreements with respect to such facilities. Failure to obtain or maintain access agreements could adversely affect Toronto Hydro.

7.13 Insurance

Although Toronto Hydro maintains insurance as described under "Business of Toronto Hydro", there can be no assurance that the Corporation will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable or that insurance will continue to be available on terms as favourable as Toronto Hydro's existing arrangements. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of Toronto Hydro's business. Toronto Hydro self-insures against certain risks (e.g., business interruption and physical damage to certain automobiles). The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by Toronto Hydro could have a material adverse effect on Toronto Hydro.

7.14 Natural and Other Unexpected Occurrences

The facilities of Toronto Hydro are exposed to the effects of natural and other unexpected occurrences. Although Toronto Hydro's facilities are constructed, operated and maintained to withstand severe weather conditions, there can be no assurance that they will successfully do so in all circumstances. For example, an ice storm in January 1998 caused significant damage to transmission and distribution facilities in Ontario, Québec and the northeastern United States. Any major damage to Toronto Hydro's facilities could result in lost revenues and repair costs that are substantial in amount. If it sustained a large uninsured loss caused by natural or other unexpected occurrences, Toronto Hydro would apply to the OEB for the recovery of the loss. There can be no assurance that the OEB would approve, in whole or in part, such an application.

PART 8 - CAPITAL STRUCTURE

8.1 Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares of which 1,000 common shares are issued and outstanding as at the date of this Annual Information Form. The City of Toronto is the sole shareholder of the Corporation. See note 18 to the Consolidated Financial Statements.

8.2 Debentures and MTN Program

On May 7, 2003, the Corporation issued $225.0 million 6.11% senior unsecured Debentures due May 7, 2013. See note 11 to the Consolidated Financial Statements.

As at the date of this Annual Information Form, the Debentures are rated "A" with a stable trend by DBRS and "A-" with a stable trend by S&P.

On January 13, 2006, the Corporation filed a short form base shelf prospectus in connection with the MTN Program. Under the terms of the MTN Program, the Corporation may offer and issue from time to time unsecured debentures in one or more series in an aggregate principal amount of up to $1 billion during the twenty-five months following the date of the prospectus. The debentures that will be issued under the MTN Program have been assigned a rating of "A" with a stable trend by DBRS and a preliminary rating of "A-" by S&P. As at the date of this Annual Information Form, no debentures have been issued under the MTN Program.

DBRS rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". A DBRS rating may be modified by the addition of "high" or "low" to indicate relative standing within the major rating categories. The "A" category is characterized as "satisfactory credit quality". An "A-(low)" rating is the lowest of the three sub-categories within the third of the ten rating categories. S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". An S&P rating may be modified by the addition of a plus or minus to indicate relative standing within the major rating categories. The "A" category is characterized as somewhat more susceptible to the adverse changes in circumstances and economic conditions than obligations in higher categories; however, the obligor's capacity to meet the financial commitment on the obligation is still strong. An "A-"rating is the lowest of the three sub-categories within the third of the ten rating categories.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating agency.

The Debentures are not listed, posted for trading or quoted on any stock exchange or quotation system.

The Debentures have been issued under the CDSX book entry system administered by CDS Clearing and Depository Services Inc. ("CDS"). Accordingly, a nominee of CDS is the registered holder of the Debentures and beneficial ownership of the Debentures is evidenced through book entry credits to securities accounts of CDS participants (e.g., banks, trust companies and securities dealers), who act as agents on behalf of beneficial owners who are their customers, rather than by physical certificates representing the Debentures.

PART 9 - DIRECTORS AND OFFICERS

9.1 Directors and Officers

The following table sets forth, for each of the directors and officers of the Corporation, the name, municipality of residence, office, principal occupation and, if a director, the date on which the person became a director. The City is the sole shareholder of the Corporation and has adopted the Shareholder Direction which sets out corporate governance principles with respect to Toronto Hydro. See "Relationship with the City of Toronto". The City elects or appoints all of the directors of the Corporation. There are currently 11 directors. Three of the directors are councillors of the City of Toronto and are not considered independent because of their positions. None of the other directors has a direct or indirect material relationship with the Corporation and are independent.

Name [1] **and Municipality of Residence**	**Office**	**Principal Occupation**	**Director Since**	**Expiry of Current Term**
Clare R. Copeland [2] Toronto, Ontario	Director and Chair of the Board of Directors	Chief Executive Officer, Falls Management Company	June 23, 1999	July 31, 2008
Janet Beed Toronto, Ontario	Director	President, Markham Stouffville Hospital	August 1, 2005	July 31, 2008
David L. Bumstead Toronto, Ontario	Director	Corporate Director	June 23, 1999	July 31, 2008
Patricia Callon Toronto, Ontario	Director	Lawyer/Consultant	August 1, 2005	July 31, 2008
Brian Chu Toronto, Ontario	Director	Partner, Bogart Robertson & Chu (a law firm)	August 1, 2005	July 31, 2008
L. Ross Cullingworth Toronto, Ontario	Director	Independent Consultant	June 23, 1999	July 31, 2008
Dr. Frank Frantisak Toronto, Ontario	Director	Partner, Frank Frantisak & Associates (a consulting company)	June 23, 1999	July 31, 2008
Jeffrey Marshall Niagara-on-the-Lake, Ontario	Director	Chairman Smith, Marshall (a strategic consulting partnership)	August 1, 2005	July 31, 2008
Gordon Perks Toronto, Ontario	Director	Councillor, City of Toronto	December 6, 2006	December 31, 2008
Bill Saundercook Toronto, Ontario	Director	Councillor, City of Toronto	December 4, 2003	December 31, 2008
David Shiner Toronto, Ontario	Director	Councillor, City of Toronto	December 4, 2003	December 31, 2008
Jean-Sebastien Couillard Toronto, Ontario	Chief Financial Officer	Chief Financial Officer, Toronto Hydro Corporation	N/A	N/A
Ave Lethbridge Toronto, Ontario	Vice-President, Organizational Effectiveness	Vice-President, Organizational Effectiveness, Toronto Hydro Corporation	N/A	N/A

Name [1] and Municipality of Residence	Office	Principal Occupation	Director Since	Expiry of Current Term
Dr. Richard Lu Toronto, Ontario	Vice-President, Environment, Health and Safety and Chief Conservation Officer	Vice-President, Environment, Health and Safety and Chief Conservation Officer, Toronto Hydro Corporation	N/A	N/A
David S. O'Brien Mississauga, Ontario	President and Chief Executive Officer	President and Chief Executive Officer, Toronto Hydro Corporation	N/A	N/A
Blair H. Peberdy Toronto, Ontario	Vice-President, Communications and Public Affairs	Vice-President, Communications and Public Affairs, Toronto Hydro Corporation	N/A	N/A
Lawrence D. Wilde Mississauga, Ontario	Vice-President, General Counsel and Corporate Secretary	Vice-President, General Counsel and Corporate Secretary, Toronto Hydro Corporation	N/A	N/A

Notes:

(1) No director serves as a director of another reporting issuer except for Mr. Copeland, who serves as a director of RioCan Real Estate Investment Trust, Danier Leather Inc., Chesswood Income Trust (formerly called Cars4U), DoveCorp Enterprises Inc. and Customer Income Direct Fund, and Mr. Marshall who serves as a director of Neenah Foundry Co., and Catalyst Paper Corporation.

(2) Mr. Copeland was a director of Moneysworth & Best Shoe Care Inc. (M&B) and he and the other directors, officers and significant shareholders of M&B were subject to an order of the Ontario Securities Commission dated July 21, 2000 that required such persons to cease trading in the securities of M&B in connection with the failure of M&B to file certain financial statements.

Except as noted above, no director or executive officer of the Corporation has, within ten years prior to the date of this Annual Information Form:

(a) been a director or executive officer of any company (including the Corporation) that, while such individual was acting in that capacity or after such person ceased to be a director or executive officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation for a period of more than 30 consecutive days or, within a year of such individual ceasing to act in such capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of its; or

(b) become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of that individual.

9.2 Principal Occupations

All of the directors and senior officers of the Corporation have held the principal occupations identified above with the same or associated companies or organizations for five years or more, except for:

Mr. Copeland, whose principal occupation was corporate director between March 2002 and October 2004 and who was Chairman and Chief Executive Officer of OSF Inc. (a manufacturer of retail store interiors) between March 2000 and March 2002;

Ms. Beed, who was Vice President and Chief Operating Officer of University Health Network/Toronto General Hospital between October 2001 and August 2005;

Ms. Callon, who was a Vice-President and Associate General Counsel of Canadian Imperial Bank of Commerce prior to September 2005;

Mr. Marshall, who was President and Chief Executive Officer of Aluma Enterprises Inc. prior to June 2003;

Mr. Couillard, who held various positions with TH Energy and the Corporation prior to May 2005 and various positions with Group Telecom prior to March 2002;

Ms. Lethbridge who held various positions with Toronto Hydro prior to September 2002 and held various positions with the Scarborough Public Utilities Commission prior to June 1998;

Mr. O'Brien, who was City Manager for the City of Mississauga prior to July 2004;

Mr. Peberdy, who was Vice-President, Communications and Corporate Planning of the Corporation prior to March 31, 2003; and

Mr. Saundercook, who was a teacher between February 2003 and November 2003, a senior associate with Sussex Strategy Group (a public affairs firm) between December 2000 and January 2003.

Mr. Perks, who was a Senior Campaigner, Toronto Environmental Alliance prior to November 2006.

9.3 Committees of the Board of Directors

The board of directors of the Corporation has established four committees.

(a) The Audit Committee is responsible for overseeing the adequacy and effectiveness of financial reporting, accounting systems and internal controls. The Audit Committee reviews the Corporation's quarterly and annual financial statements as well as financial statements prepared in connection with securities offerings or required by applicable regulatory authorities, reviews the audit plans of the external auditors, reviews officers' personal expenses on an annual basis and recommends the auditor for appointment by the Corporation's sole shareholder. Members of the Audit Committee are Mr. Bumstead, Mr. Chu, and Mr. Cullingworth. Mr. Cullingworth is the Chair of the Audit Committee. See "Audit Committee" below.

(b) The Corporate Governance Committee is responsible for considering and making recommendations to the board of directors of the Corporation with respect to matters relating to the corporate governance of Toronto Hydro, including board and committee composition and mandates, and guidelines for assessing the effectiveness of the board of directors and its committees and procedures to ensure that the board of directors functions independently from management. Management undertakes orientation and education programs for new directors. Members of the Corporate Governance Committee are Mr. Chu, Mr. Copeland, and Dr. Frantisak. Mr. Chu is the Chair of the Corporate Governance Committee.

(c) The Compensation Committee is responsible for reviewing the performance and remuneration of senior executives and succession planning for senior management positions. Members of the Compensation Committee are: Ms. Beed, Mr. Copeland and Mr. Marshall. Mr. Marshall is the Chair of the Compensation Committee.

(d) The Environment, Health and Safety Committee is responsible for considering and making recommendations to the board of directors with respect to matters of health, safety and the environment, including occupational health and safety, energy conservation, environmental

protection and management and protection and enhancement of the urban forest. Members of the Environment, Health and Safety Committee are Dr. Frantisak, Mr. Saundercook and Ms. Callon. Dr. Frantisak is the Chair of the Environment, Health and Safety Committee.

9.4 Audit Committee

The board of directors of the Corporation has established the Audit Committee to assist the board in fulfilling its corporate governance and oversight responsibilities with respect to financial reporting, internal financial control structure, financial risk management systems and external audit functions. The Committee is comprised of Mr. Cullingworth (Chair), Mr. Bumstead and Mr. Chu, each of whom is independent and financially literate within the meaning of applicable Canadian securities laws.

(a) Charter

Under the terms of its charter, the Audit Committee is responsible for:

- managing the relationship between the Corporation and its external auditors, including: appointing and replacing the external auditors, subject to shareholder approval; setting the compensation of the external auditors subject to the approval of the board of directors or the shareholder, as applicable, overseeing the work of the external auditors (including resolving disagreements between management and the external auditors with respect to financial reporting); pre-approving all audit services and permitted non-audit services to be provided to the Corporation and its subsidiary entities by the external auditors; ensuring that the external auditors report to the Audit Committee in a timely manner with respect to all required matters; reviewing and approving the hiring policies of the Corporation with respect to present and former partners and employees of the external auditors; ensuring the rotation of the audit partner having primary responsibility for the audit of the Corporation, the audit partner responsible for reviewing the audit and the external auditors at such intervals as may be required; and reviewing and assessing the performance, independence and objectivity of the external auditors;

- overseeing the external audit of the Corporation, including: reviewing and approving the engagement letter and the audit plan (including identified financial risk areas); reviewing and assessing the accounting and reporting practices and principles used by the Corporation in preparing its financial statements; reviewing and assessing the results of the external audit and the external auditors' opinion on the financial statements; reviewing and discussing with the external auditors and management any management or internal control letters issued or proposed to be issued by the external auditors; reviewing and discussing with the external auditors any problems or difficulties encountered by them in the course of their audit work and management's response; and reviewing and discussing with legal counsel any legal matters that may have a material impact on the financial statements, operations, assets or compliance policies of the Corporation and any material reports or enquiries received by the Corporation and its subsidiary entities from regulators or government agencies;

- reviewing, approving and, where required, recommending to the board for approval, the financial statements, management's discussion and analysis of financial condition and results of operations and interim financial reports of the Corporation, annual information form and other public disclosure of financial information extracted from the financial statements of the Corporation with particular focus on the quality and appropriateness of accounting and reporting practices and principles and any changes thereto, major estimates or judgments, including alternative treatments of financial information discussed by management and the external auditors, the results of such discussions and the treatment preferred by the external auditors, material financial risks, material transactions, material adjustments, compliance with loan agreements, material off-balance sheet transactions and structures, compliance with accounting standards, compliance with legal and regulatory requirements and disagreements with management;

- overseeing the internal financial control structure and financial risk management systems of the Corporation, including: reviewing and discussing with management and the external auditors and

the quality and adequacy of internal control over the financial reporting structures of the Corporation (including any major deficiencies or weakness and the steps taken by management to rectify these deficiencies or weaknesses); reviewing and discussing with management and the external auditors the risk assessment and risk management policies of the Corporation, the major financial risk exposures of the Corporation and the steps taken by management to monitor and control these exposures; and reviewing and discussing with the Chief Executive Officer and the Chief Financial Officer of the Corporation the procedures undertaken by them in connection with the certifications required to be given by them in connection with annual and other filings required to be made by the Corporation under applicable securities laws; and

- establishing adequate policies and procedures, or requiring that adequate policies and procedures are established, with respect to the following (and annually assessing the adequacy of these procedures): the review of the public disclosure of financial information extracted from the financial statements of the Corporation; the receipt, retention and treatment of complaints received by the Corporation with respect to accounting, internal accounting controls or auditing matters; and the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

(b) Policy on the Provision of Services by the External Auditors

The Audit Committee has developed a Policy on the Provision of Services by the External Auditors. Under the terms of the Policy:

- the external auditors may not provide services to Toronto Hydro that impair or have the potential to impair the independence and objectivity of the external auditors in relation to the external audit function (generally, prohibited services include services where the external auditors participate in activities that are normally undertaken by management of Toronto Hydro, are remunerated through a "success fee" structure, act in an advocacy role for Toronto Hydro or may be required to audit their own work);

- the Audit Committee has pre-approved certain audit and permitted non-audit services as services that the auditors may provide to Toronto Hydro, including: services that constitute the agreed scope of the external audit or interim reviews of Toronto Hydro; services that are outside the agreed scope of, but are consistent with, the external audit or interim reviews of Toronto Hydro; tax services that do not compromise the independence and objectivity of the external auditors in relation to the external audit; and other services of an advisory nature that do not compromise the independence and objectivity of the external auditors in relation to the external audit work; and

- an authorization process has been established which provides, among other things: the Chief Financial Officer may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $25,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chief Financial Officer must report all such authorized engagements to the Audit Committee at its next meeting); the Chair of the Audit Committee may authorize in advance all engagements of the external auditors to provide pre-approved services (other than audit services) to Toronto Hydro up to a maximum of $50,000 for any engagement and up to a maximum of $100,000 for all engagements in any fiscal quarter (the Chair must report all such authorized engagements to the Audit Committee at its next meeting); and the Audit Committee must authorize in advance all engagements of the external auditors to provide pre-approved services to Toronto Hydro above the prescribed thresholds and all engagements to provide services that are not pre-approved services regardless of the dollar value of the services.

Exceptions can be made to this Policy where the exceptions are in the interests of Toronto Hydro and appropriate arrangements are established to ensure the independence and objectivity of the external auditors in relation to the external audit. Any exception must be authorized by the Audit Committee and must be reported to the board of directors of the Corporation.

(c) External Auditors Service Fees

The Corporation's auditors are Ernst & Young LLP, Chartered Accountants. The table below sets out the fees billed by the Corporation's auditors for each of last two fiscal years in respect of the services noted below.

	Year ended December 31,	
	2006	**2005**
Audit fees[1]…….	$395,303	$825,400
Audit-related fees[2]	$150,525	$158,500
Tax fees[3]	$125,450	-
All other fees[4]	$68,382	$116,400

Notes:

(1) Includes fees for audit services.

(2) Includes fees for interim reviews, assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported under (1) above.

(3) Includes fees for professional services rendered in respect of tax compliance, tax advice and tax planning.

(4) Includes fees for products and services other than those referred to in note (1), (2) and (3) above. Amount shown primarily relates to professional fees in respect of the MTN Program, internal controls compliance and acquisition of street lighting and expressway lighting assets from the City of Toronto.

(d) Reliance on Exemption

In preparing the disclosure under "Audit Committee", the Corporation has relied on an exemption that is available to venture issuers with respect to certain disclosure matters.

9.5 Code of Business Conduct

All employees, officers and directors of Toronto Hydro are required to comply with the principles set out in the Code of Business Conduct, which was implemented by Toronto Hydro in 2004. The Code provides for the appointment of an Ethics and Compliance Officer and establishes a direct hotline to the Ethics and Compliance Officer by which perceived violations of the principles set out in the Code may be reported, anonymously or otherwise. The Ethics and Compliance Officer reports quarterly to the Audit Committee on the nature of complaints received including those related to audit and accounting matters.

9.6 Board Assessments

The Board conducts periodic assessments of the performance of the Board and its committees through the use of board evaluations which are completed by each of the directors and selected senior officers.

PART 10 - EXECUTIVE COMPENSATION

10.1 Compensation of Directors

Directors of the Corporation, other than Councillors of the City of Toronto, are compensated for their services as directors through a combination of retainer fees and meeting attendance fees. These fees are set by the sole shareholder of the Corporation, the City of Toronto. The annual retainer fees are as follows: chair of the board of directors – $75,000 and each of the other directors – $12,500. The meeting attendance fees are as follows: each meeting of the board of directors attended – $1,000 and each meeting of the Audit Committee, Corporate Governance Committee, Compensation Committee and Environment, Health and Safety Committee attended — $1,000, subject to annual maximum fees per committee member of $5,000 for the Audit Committee, Corporate Governance Committee, and the Environment, Health and Safety Committee and $4,000 for the Compensation Committee. The Chair receives no meeting attendance fees.

Councillors of the City of Toronto receive no remuneration for their services as directors of the Corporation.

10.2 Compensation of Officers

The following table provides a summary of the compensation earned during the years ended December 31, 2006, 2005 and 2004 by the Chief Executive Officer of the Corporation, the Chief Financial Officer of the Corporation and the three most highly compensated executive officers of Toronto Hydro who were serving as executive officers at December 31, 2006 (collectively, the "Named Executive Officers" or "NEOs"):

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
NEO Name and Principal Position	**Year**	**Salary [1] ($)**	**Bonus [2] ($)**	**Other Annual Compensation[3] ($)**	**Securities Under Options/SARs Granted (#)**	**Shares or Units Subject to Resale Restrictions ($)**	**LTIP Payouts ($)**	**All Other Compensation [4] ($)**
David S. O'Brien	2006	348,218[5]	149,711	19,663	-	-	-	-
President and Chief Executive Officer,	2005	293,808[6]	66,172	18,458	-	-	-	-
Toronto Hydro Corporation	2004	132,212[7]	-	7,820	-	-	-	-
Jean-Sebastien Couillard	2006	194,615	49,350	19,134	-	-	-	-
Chief Financial Officer, Toronto Hydro Corporation	2005	171,912[8]	47,303	18,002	-	-	-	-
	2004	152,000	40,014	16,429	-	-	-	-
Anthony M. Haines	2006	247,353[9]	59,883	19,700	-	-	-	-
President, Toronto Hydro-Electric	2005	129,808[10]	N/A	10,755	-	-	-	102,723[11]
System Limited	2004	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lawrence D. Wilde	2006	185,553	42,359	19,090	-	-	-	-
Vice President, General Counsel,	2005	179,674	37,123	18,038	-	-	-	-
Toronto Hydro Corporation	2004	160,712	35,625	16,450	-	-	-	-
Robert King	2006	178,646[12]	41,580	19,051	-	-	-	-
Chief Operating Officer, Toronto Hydro-Electric	2005	162,647	42,315	17,957	-	-	-	-
System Limited	2004	160,462	42,369	16,431	-	-	-	-
James A. Black[13]	2006	231,224	91,348	19,261	-	-	-	-
	2005	220,210	103,469	18,173	-	-	-	-
	2004	229,770	99,681	16,644	-	-	-	-

Notes:

(1) Amounts shown in this column have been rounded to the nearest dollar and include vacation pay.

(2) Amounts shown in this column are bonuses earned by the Named Executive Officer in respect of the previous financial year.

(3) Amounts shown in this column include pension adjustments and life insurance premiums.

(4) The value of total annual perquisites and other personal benefits for each Named Executive Officer does not exceed the lesser of $50,000 and 10% of total annual salary and bonus and is not reported herein.

(5) Mr. O'Brien was granted a $25,000 retroactive increase in his 2005 base salary in January 2006. This amount was paid to Mr. O'Brien in February 2006 and is included in the amount shown.

(6) This amount does not include a $25,000 retroactive increase in respect to 2005 base pay which was paid in February 2006.

(7) Mr. O'Brien assumed this position in July 2004 and would have earned a total base salary of $275,000 had he worked for the Corporation for the whole of 2004.

(8) Mr. Couillard assumed this position in May 2005 and would have earned a total base salary of $175,000 had he held the office of Chief Financial Officer for the whole of 2005.

(9) Mr. Haines assumed this position in September 2006 and would have earned a total base salary of $275,000 had he held the office of President of Toronto Hydro-Electric System Limited for the whole of 2006.

(10) Mr. Haines assumed the position of Chief Administrative Officer in May 2005 and would have earned a total base salary of $225,000 had he held that position for the whole of 2005.

(11) The amount shown was paid as a reimbursement for employee relocation.

(12) Mr. King assumed this position in September 2006, and would have had earned a total base salary of $200,000 had he held the office of Chief Operating Officer for the whole of 2006.

(13) On August 2, 2006, the Corporation entered into a severance agreement with Mr. Black. Pursuant to this severance agreement, Mr. Black is entitled to receive a base salary of $231,415 for each of 2006, 2007, 2008 and $96,422.91 for 2009 and an annual bonus of $128,435 for 2006, $109,892 for each of 2007 and 2008 and $45,788 for 2009.

10.3 Employment Agreements

Each of Mr. O'Brien, Mr. Couillard, and Mr. Wilde has entered into an employment agreement with the Corporation, and each of Mr Haines and Mr. King has entered into an employment agreement with LDC, that provides for an annual base salary ($360,500 for 2007 in the case of Mr. O'Brien), ($200,850 for 2007 in the case of Mr. Couillard), ($190,658 for 2007 in the case of Mr. Wilde), ($283,250 for 2007 in the case of Mr. Haines), and ($201,789 for 2007 in the case of Mr. King) and retirement, health and other benefits. Each of the Named Executive Officers is also entitled to an annual bonus based on the achievement of individual and corporate goals established at the beginning of each year (the target amount of which is 65% of the base salary in the case of Mr. O'Brien, 50% of the base salary in the case of Mr. Haines, 40% of the base salary in the case of Mr. King and Mr. Couillard and 30% of the base salary in the case of Mr. Wilde). In the case of Mr. O'Brien, the Compensation Committee, and in the case of Mr. Haines, Mr. Couillard, Mr. King and Mr. Wilde, the President and Chief Executive Officer, may determine to increase the target amount of the bonus by up to 50% for each Named Executive Officer in the event that the Corporation has exceeded the corporate goals, and the Named Executive Officer has exceeded his individual goals for a given year. In addition, if the employment of Mr. O'Brien or Mr. Haines is terminated by the Corporation, or LDC, as applicable, without cause, Mr. O'Brien and Mr. Haines are each entitled to a payment equal to 6 months of base salary if employed up to one year with the Corporation, or LDC, as applicable, 12 months of base salary if employed more than one year but less than 2 years with the Corporation, or LDC, as applicable, and 18 months of base salary if employed 2 or more years with the Corporation, or LDC, as applicable. Mr. Wilde is entitled to a payment equal to 24 months of base salary if his employment is terminated by the Corporation without cause. Mr. Couillard is entitled to a payment equal to 18 months of base salary if his employment is terminated by the Corporation without cause.

10.4 Pension Arrangements

The Named Executive Officers participate in OMERS, a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Plan benefits are determined by a formula based on highest average contributory earnings and years of service with an offset for Canada Pension Plan benefits. Plan benefits are indexed to increases in the Consumer Price Index subject to an annual maximum of 6%. Any increase in the Consumer Price Index above 6% per year is carried forward for later years.

Both participating employers and participating employees are required to make plan contributions based on the participating employees' contributory earnings. Because of a plan surplus, a contribution holiday was in effect from August 1998 until December 2002. Contributions recommenced in January 2003. Plan benefits in excess of the maximum permitted under the ITA are funded through contributions to a retirement compensation arrangement.

The following table sets forth the aggregate normal annual pension benefits payable to participating employees under the plan at age 65 assuming that the year's maximum pensionable earnings under the Canada Pension Plan in the future is the same as in 2006.

	Years of Service				
Remuneration	**15**	**20**	**25**	**30**	**35**
$125,000	$37,500	$50,000	$62,500	$75,000	$87,500
150,000	45,000	60,000	75,000	90,000	105,000
175,000	52,500	70,000	87,500	105,000	122,500
200,000	60,000	80,000	100,000	120,000	140,000
225,000	67,500	90,000	112,500	135,000	157,500
250,000	75,000	100,000	125,000	150,000	175,000
300,000	90,000	120,000	150,000	180,000	210,000
400,000	120,000	160,000	200,000	240,000	280,000

Notes:

(1) At December 31, 2006, the Named Executive Officers had the following years of service: Mr. O'Brien – 32.9 years (of which 2.5 years were accumulated at the Corporation); Mr. Haines – 3.2 years (of which 1.6 years were accumulated at Toronto Hydro); Mr. King – 30.9 (of which 16.2 years were accumulated at Toronto Hydro); Mr. Couillard – 4.8 years; Mr. Black – 29.3 years; Mr. Wilde –5.3 years.

(2) Contributory earnings for purposes of the plan consist of all basic remuneration for work done or services performed (including the salary set out in the "Salary" column of the Summary Compensation Table above) excluding any benefits, overtime pay, automobile, entertainment or other allowance or unusual payments.

10.5 Report on Executive Compensation

The Compensation Committee is responsible for recommending to the board of directors of the Corporation the compensation of the executive officers of the Corporation. In establishing and implementing compensation policy, the committee considers the recommendations of the President and Chief Executive Officer and makes reference to comparative industry data. In determining compensation for executive officers, the committee takes into consideration individual responsibilities and performance and comparative levels of compensation. Compensation levels are reviewed in the early part of each year based on individual and corporate performance during the preceding year. Corporate performance is measured in terms of the attainment of certain financial and non-financial targets set at the beginning of the year. Financial targets are broken down by business unit and are determined based on the consolidated audited financial statements of the Corporation. Non-financial targets include, but are not limited to, those in relation to operations, safety and customers.

The guiding philosophy of the Compensation Committee and the board of directors of the Corporation in the determination of executive compensation is pay-for-performance and the need to provide a total compensation package that will attract and retain qualified and experienced executives. Executive compensation consists of two components: base salary and annual bonuses.

Base salary is one element of an executive's total compensation. Base salary levels are benchmarked to companies of comparable size and scope in both the greater Toronto and national markets. Jobs are matched to benchmarks roles in published compensation surveys. Annually, adjustments to base salaries for individual executives are based on a review of the performance of the individual relative to established pay for performance guidelines set periodically by Toronto Hydro. These guidelines consider the competitiveness of current compensation levels, anticipated changes in market pay and the performance of the corporation.

Generally, annual bonus awards are closely aligned with the Corporation's performance and are designed to reward executives for reaching individual and corporate objectives established at the beginning of each year. Annual bonus awards are expressed as a percentage of base salary and are designed to retain and motivate executives and to reward them for their performance during the preceding year.

Mr. O'Brien's base salary as President and Chief Executive Officer of the Corporation for 2006 was $323,700. Effective January 1 2007, Mr. O’Brien’s base salary will be increased to $350,000 with a target amount of 65% of the base salary for his annual bonus based on the achievement of individual and corporate goals established at the

beginning of the year. The Compensation Committee may determine to increase the target amount of the bonus by up to 50% in the event that the Corporation has exceeded the corporate goals and Mr. O'Brien has exceeded his individual goals. In determining the amount of Mr. O'Brien's compensation, the Compensation Committee considered a number of qualitative and quantitative factors which included financial results**,** strategic planning and initiatives, personal leadership, business acumen and the compensation paid by a benchmark group of Canadian utility and energy companies to their chief executive officers.

PART 11 - LEGAL PROCEEDINGS

Toronto Hydro is a party to various legal proceedings relating to the period before July 1999 when Toronto Hydro acquired the assets and liabilities of the Toronto Hydro-Electric Commission. In addition, Toronto Hydro is a party to various legal proceedings arising since that time in the normal course of business. The pending legal proceedings containing material claims affecting Toronto Hydro are described below:

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada ruled that Consumers' Gas was required to repay that portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement however, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff, as well as to receive lawyer's fees in connection with that effort. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below and in the Corporation's consolidated financial statements for the year ended December 31, 2006, in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario municipal electric utilities under the Class Proceedings Act, 1992 seeking $500.0 million in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the Class Proceedings Act, 1992 seeking $64.0 million in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is also at the preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the Criminal Code is fact specific in each circumstance. Accordingly,

given the preliminary status of these actions, it is not possible at this time to quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

PART 12 - MATERIAL CONTRACTS

Except for the following, Toronto Hydro has not entered into any material contract in the most recently completed financial years, or before the most recently completed financial year, if such contract is still in effect:

(a) the Amended and Restated City Note described under Part 5 -Relationship with the City of Toronto;

(b) the indenture and the supplemental indenture under which the Debentures were issued; and

(c) the dealer agreement relating to the MTN Program.

Copies of these material contracts are available on the Canadian Securities Administrators' web site at www.sedar.com.

PART 13 - INTERESTS OF EXPERTS

13.1 Names of Experts

The external auditor of the Corporation is Ernst & Young LLP.

PART 14 - ADDITIONAL INFORMATION

Upon request to the Secretary of the Corporation at the Corporation's principal office at 14 Carlton Street, Toronto, Ontario, M5B 1K5, the Corporation will provide any person with a copy of:

- this Annual Information Form;
- annual filings made by the Corporation in lieu of an information circular;
- the most recent unaudited interim financial statements of the Corporation; and
- any other documents that are incorporated by reference into a preliminary short form prospectus or short form prospectus filed in respect of a distribution of securities of the Corporation.

A copy of any of these documents may be obtained without charge at any time when a preliminary short form prospectus has been filed in respect of a distribution of any securities of the Corporation or any securities of the Corporation are in the course of a distribution pursuant to a short form prospectus. At any other time, any document referred to above may be obtained by security holders of the Corporation without charge and by any other person upon payment of a reasonable charge. Copies of these documents and additional information relating to the corporation are also available on SEDAR at www.sedar.com.

Additional financial information is provided in the Consolidated Financial Statements and Management's Discussion and Analysis of Financial Condition and Results of Operations, copies of which are attached to this Annual Information Form as Annex A and Annex B, respectively.

ANNEX A
CONSOLIDATED FINANCIAL STATEMENTS

ANNEX A

CONSOLIDATED FINANCIAL STATEMENTS

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AUDITORS' REPORT

To the Shareholder of
Toronto Hydro Corporation

We have audited the consolidated balance sheets of **Toronto Hydro Corporation** [the "Corporation"] as at December 31, 2006 and 2005 and the consolidated statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Toronto, Canada,
February 21, 2007 [except as to note 26,
which is as of March 1, 2007].

Chartered Accountants

Toronto Hydro Corporation

CONSOLIDATED BALANCE SHEET

[in thousands of dollars]

As at December 31	2006 $	2005 $
ASSETS		
Current		
Cash and cash equivalents	**327,524**	448,370
Accounts receivable, net of allowance for doubtful accounts	**218,452**	174,499
Unbilled revenue	**216,857**	271,367
Inventories	**22,458**	18,189
Prepaid expenses	**2,277**	2,168
Electricity mark-to-market assets *[note 15]*	**-**	113,297
Future income tax assets *[note 17]*	**791**	33,195
Assets from discontinued operations *[note 23]*	**12,098**	-
Total current assets	**800,457**	1,061,085
Property, plant and equipment, net *[note 5]*	**1,656,868**	1,624,741
Intangible assets, net *[note 6]*	**49,266**	41,926
Regulatory assets *[note 7]*	**66,528**	63,752
Other assets *[note 8]*	**2,578**	5,490
Future income tax assets *[note 17]*	**16,009**	22,264
Total assets	**2,591,706**	2,819,258
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**284,869**	423,780
Current portion of other liabilities *[note 10]*	**16,952**	39,210
Current portion of deferred revenue	**7,320**	20,423
Current portion of promissory note payable *[note 11]*	**245,058**	330,000
Electricity mark-to-market liabilities *[note 15]*	**-**	86,875
Future income tax liabilities *[note 17]*	**-**	40,923
Liabilities from discontinued operations *[note 23]*	**906**	-
Total current liabilities	**555,105**	941,211
Long-term liabilities		
Debentures *[note 11]*	**225,000**	225,000
Promissory note payable *[note 11]*	**735,173**	650,231
Post-employment benefits *[note 12]*	**134,682**	125,415
Regulatory liabilities *[note 7]*	**11,840**	13,297
Other liabilities *[note 13]*	**3,949**	9,077
Asset retirement obligations *[note 14]*	**7,581**	5,691
Customers' advance deposits	**25,944**	2,900
Future income tax liabilities *[note 17]*	**368**	569
Total long-term liabilities	**1,144,537**	1,032,180
Total liabilities	**1,699,642**	1,973,391
Commitments and contingencies *[notes 20 and 21]*		
Shareholder's equity		
Share capital *[note 18]*	**567,817**	567,817
Retained earnings	**324,247**	278,050
Total shareholder's equity	**892,064**	845,867
Total liabilities and shareholder's equity	**2,591,706**	2,819,258

ON BEHALF OF THE BOARD:

Clare R. Copeland, Director

L. Ross Cullingworth, Director

CONSOLIDATED STATEMENT OF INCOME

[in thousands of dollars, except for per share amounts]

Year ended December 31	2006 $	2005 $
Revenues	**2,247,008**	2,606,272
Costs		
Purchased power and other	**1,705,845**	2,059,789
Operating expenses	**194,216**	191,185
Depreciation and amortization	**137,344**	131,595
	2,037,405	2,382,569
Income before interest, other and provision for payments in lieu of corporate taxes	**209,603**	223,703
Interest income	**17,726**	14,116
Interest expense		
Long-term debt	**(75,894)**	(80,403)
Other interest	**(2,902)**	(2,700)
Other	**89**	5,040
Income before provision for payments in lieu of corporate taxes	**148,622**	159,756
Provision for payments in lieu of corporate taxes *[note 17]*	**58,403**	68,839
Income from continuing operations	**90,219**	90,917
Income from discontinued operations - net of tax *[note 23]*	**2,178**	1,528
Net income	**92,397**	92,445
Basic and fully diluted net income per share from continuing operations *[note 22]*	90,219	90,917
Basic and fully diluted net income per share from discontinued operations *[note 22]*	2,178	1,528
Basic and fully diluted net income per share	**92,397**	92,445

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31	2006 $	2005 $
Retained earnings, beginning of year	**278,050**	253,605
Net income	**92,397**	92,445
Dividends *[note 18]*	**(46,200)**	(68,000)
Retained earnings, end of year	**324,247**	278,050

Toronto Hydro Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31	2006 $	2005 $
OPERATING ACTIVITIES		
Income from continuing operations	**90,219**	90,917
Adjustments for non-cash items		
Depreciation and amortization	**137,344**	131,595
Net change in other assets and liabilities	**(3,191)**	1,878
Electricity mark-to-market assets and liabilities	**26,422**	1,274
Post-employment benefits	**9,267**	7,298
Future income taxes	**(2,488)**	(3,121)
Gain on disposals of property, plant and equipment	**(89)**	(5,040)
Changes in non-cash working capital balances		
Decrease (increase) in accounts receivable	**(44,003)**	9,080
Decrease (increase) in unbilled revenue	**54,510**	(25,245)
Decrease (increase) in inventories	**(4,269)**	1,719
Decrease (increase) in prepaid expenses	**(60)**	45
Increase (decrease) in accounts payable and accrued liabilities	**(137,787)**	93,045
Increase (decrease) in deferred revenue	**(13,179)**	20,423
Increase in current portion of other liabilities	**32**	1,219
Net cash provided by operating activities	**112,728**	325,087
INVESTING ACTIVITIES		
Purchase of property, plant and equipment	**(166,806)**	(192,241)
Purchase of intangible assets	**(18,501)**	(8,114)
Net change in regulatory assets and liabilities	**(4,233)**	20,548
Proceeds on disposal of property, plant and equipment	**938**	5,085
Net cash used in investing activities	**(188,602)**	(174,722)
FINANCING ACTIVITIES		
Increase (decrease) in customers' advance deposits	**1,835**	(20,081)
Repayment of capital lease liability	**(1,182)**	(1,866)
Dividends paid *[note 18]*	**(46,200)**	(68,000)
Net cash used in financing activities	**(45,547)**	(89,947)
Net cash provided by (used in) continuing operations	**(121,421)**	60,418
Net cash provided by discontinued operations	**575**	1,327
Net increase (decrease) in cash and cash equivalents during the year	**(120,846)**	61,745
Cash and cash equivalents, beginning of year	**448,370**	386,625
Cash and cash equivalents, end of year	**327,524**	448,370
Supplementary cash flow information		
Total interest paid	77,442	81,657
Payments in lieu of corporate income taxes	106,771	74,780

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2006

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the Business Corporations Act (Ontario) along with two wholly-owned subsidiary companies, Toronto Hydro-Electric System Limited ["LDC"] and Toronto Hydro Energy Services Inc. ["TH Energy"]. The incorporation was required in accordance with the provincial government's Electricity Act, 1998.

Under the terms of By-law No. 374-1999 of the City of Toronto ["Transfer By-law"] made under section 145 of the Electricity Act, 1998 and in accordance with continuity of interest accounting, the former Toronto Hydro-Electric Commission and the City of Toronto [the "City"] transferred, at book value, their assets and liabilities [effective July 1, 1999] and employees [effective January 1, 2000] associated with:

[a] electricity distribution to LDC in consideration for the issuance of equity securities of LDC and long-term notes payable to the City; and

[b] electricity generation, co-generation and energy services to TH Energy in consideration for the issuance of equity securities of TH Energy.

The equity securities of LDC and TH Energy were subsequently transferred by the City to the Corporation in consideration for the issuance of equity securities of the Corporation to the City.

Certain surplus real property assets and cash funds were excluded from the transfer and were retained by the City. In addition, the long-term debt incurred by the City on behalf of the former Toronto Hydro-Electric Commission was excluded from the liabilities transferred and was retained by the City.

The book value of the assets transferred at July 1, 1999 was $1,548,048,000. The principal amount of the long-term notes payable to the City was $980,231,000 and the value of the common shares of the Corporation received by the City was $567,817,000.

The Corporation supervises the operations of, and provides corporate and management services and strategic direction to, its subsidiary companies [each of which is listed below, incorporated under the BCA and wholly-owned, directly or indirectly, by the Corporation]:

[a] LDC [incorporated June 23, 1999] – which distributes electricity to customers located in the City and is subjected to rate regulation.

[b] TH Energy [incorporated June 23, 1999] – which owns and operates street lighting and expressway lighting systems located in the City and is engaged in the sale of energy efficiency products and services.

[c] Toronto Hydro Telecom Inc. ["Telecom"] [incorporated September 26, 2000] – which provides fibre optic cable capacity and manages data communications services.

[d] 1455948 Ontario Inc. [incorporated December 21, 2000] – which owns a 50% interest in EBT Express Partnership ["EBT Express"], a joint venture with a wholly-owned subsidiary of Ontario Power Generation Inc. EBT Express owns a 67% controlling interest in The SPi Group, a corporation formed to provide, among other things, centralized electronic data management and transaction services to energy industry participants.

The principal business of the Corporation is the regulated distribution of electricity by LDC.

2. REGULATION

In April 1999, the government of Ontario initiated a restructuring of Ontario's electricity industry. The restructuring was intended, among other things, to facilitate competition in the generation and sale of electricity, to protect the interests of consumers with respect to prices and the reliability and quality of electricity service and to promote economic efficiency in the generation, transmission and distribution of electricity.

The Ontario Energy Board [the "OEB"] has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfill obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

[i] *Electricity Price and Related Rebates*. The electricity price and related rebates represent a pass through of the commodity cost of electricity.

[ii] *Distribution Rate*. The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity and sustained periods of moderate weather which decrease the consumption of electricity).

[iii] *Retail Transmission Rate*. The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

[iv] *Wholesale Market Service Charge*. The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

3. ELECTRICITY DISTRIBUTION RATES

In connection with the restructuring of Ontario's electricity industry in 1999, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a market-based rate of return of 9.88% on the deemed debt to equity structure of LDC of 65:35. The adjustment was being phased in over three adjustment periods to lessen the rate impact on customers. Effective on each of December 1, 2000 and March 1, 2002, the OEB authorized LDC to increase its distribution rates to allow for the recovery of additional annual revenue of $39.8 million.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39.8 million, representing the third and final adjustments necessary to achieve a market-based rate of return of 9.88%. The rate increase was effective as of April 1, 2005 and subjected the LDC to a financial commitment to invest $39.8 million in Conservation and Demand Management ["CDM"] activities by September 2007.

In April 2006, the OEB approved a decrease in the distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $57,956,000, including the new regulatory treatment for revenues relating to smart meters [see *note 7*]. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on deemed equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980,231,000 promissory note between LDC and the Corporation from 6.8% to 5% per annum.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates and other permitted recoveries.

4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Corporation have been prepared in accordance with Canadian generally accepted accounting principles ["GAAP"], including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ["AP Handbook"] and reflect the significant accounting policies summarized below.

a) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its wholly-owned subsidiaries. All significant intercompany balances and transactions have been eliminated.

b) Regulation

The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in an unregulated environment:

Regulatory Assets and Liabilities

In accordance with Canadian Institute of Chartered Accountants ["CICA"] Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation" ["AcG-19"], certain costs and variance account balances deemed to be "regulatory assets" or "regulatory liabilities" are reflected separately on LDC's balance sheet until the manner and timing of disposition is determined by the OEB *[note 7]*.

Payments in lieu of corporate taxes

The Corporation and its subsidiaries are exempt from tax under the *Income Tax Act (Canada)* ["ITA"] and the *Corporations Tax Act (Ontario)*, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income and each of its subsidiaries is derived from activities carried on outside the municipal geographical boundaries of the City.

The Corporation and each of its subsidiaries is a "municipal electricity utility" ["MEU"] for purposes of the payments in lieu of corporate taxes ["PILs"] regime contained in the Electricity Act, 1998. The Electricity Act, 1998 provides that a MEU that is exempt from tax under the ITA and the *Corporations Tax Act (Ontario)* is required to make, for each taxation year, a PILs, to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

The PILs regime came into effect on October 1, 2001, at which time the Corporation and each of its subsidiaries were deemed to have commenced a new taxation year for purposes of determining the respective liabilities for PILs. Accordingly, the Corporation and its subsidiaries were deemed to have disposed of their assets at their then fair market value and to have re-acquired such assets at the same amount. The differences between the financial statement carrying value and tax basis of assets and liabilities were accounted for by the Corporation as follows:

[a] in the case of the Corporation's unregulated businesses, the liability method of accounting was applied in accordance with recommendations of the CICA; and

[b] in the case of the Corporation's regulated electricity distribution business, the taxes payable method of accounting was applied in accordance with recommendations of the CICA and the OEB.

Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arise from temporary differences in the accounting and tax basis of assets and liabilities. Future tax assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time.

The OEB's Electricity Distribution Rate Handbooks, issued in March 2000 and May 2005, provide for the recovery of PILs by LDC through annual distribution rate adjustments as permitted by the OEB. The OEB-approved distribution rate for PILs recoveries is based on estimated consumption volumes. The difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs amount up to April 30, 2006, is tracked by

LDC as a variance amount in accordance with OEB guidelines for regulatory assets and with criteria set out in the AP Handbook. Commencing May 1, 2006, any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application are tracked by LDC as variance amounts.

Contributions in aid of construction

Capital contributions received from outside sources are used to finance additions to property, plant and equipment of LDC. According to the AP Handbook, capital contributions received are treated as a "credit" to property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

Spare transformers

Spare transformers are items that are expected to substitute for original distribution plant transformers when these original plant assets are being repaired and are held and dedicated for the specific purpose of backing up plant in service as opposed to assets available for other uses. According to the criteria set out in the AP Handbook, spare transformers are treated as capital assets *[note 5]*, which would be recorded as inventory under Canadian GAAP for unregulated businesses.

c) Cash and cash equivalents

Effective January 1, 2006, the Corporation changed the terms to maturity in the definition of cash equivalents from five months or less to 90 days or less from the date of acquisition. This change resulted in no impact on the audited consolidated financial statements as at December 31, 2006 and 2005.

d) Inventories

Inventories consist primarily of maintenance and construction materials and are stated at the lower of cost and replacement cost, with cost determined on an average cost basis net of the provision for obsolescence.

e) Property, plant and equipment and depreciation

Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average service lives, except in those instances where specific identification allows their removal at retirement or disposition. Gains or losses at retirement or disposition of such assets are credited or charged to "Other" in the Consolidated Statement of Income.

In the event that facts and circumstances indicate that property, plant and equipment may be impaired, an evaluation of recoverability is performed. For purposes of such an evaluation, the estimated future undiscounted cash flows associated with the asset are compared to the carrying amount of the asset to determine if a write-down is required. The impairment loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

Depreciation is provided on a straight-line basis over the estimated service lives at the following annual rates:

Buildings	1.7% to 10.0%
Stations	2.9% to 5.0%
Distribution lines	2.5% to 25.0%
Transformers	3.3% to 4.0%
Meters	2.9% to 4.0%
Other capital assets	6.7% to 12.5%
Communications	5.0% to 20.0%
Computer hardware	20.0% to 25.0%
Rolling stock	12.5% to 33.3%
Equipment and tools	10.0%

Construction in progress includes assets not currently in use which are not depreciated.

f) Intangible assets

Intangible assets, which lack physical substance, are stated at cost. Amortization is provided on a straight-line basis over their estimated useful service lives at the following annual rates:

Land rights	2.0%
Computer software	14.0% to 33.0%
Capital contributions	4.0%
Leasehold improvements	Over the remaining lease term

Software in development includes assets not currently in use which are not amortized.

g) Deferred debt issue costs

In 2003, the Corporation incurred debt issue costs arising from the Corporation's debenture offering *[note 8]*. Deferred debt issue costs are included in "Other assets" and represent the unamortized amounts of debt costs arising from the issuance of debt, and other related costs. Deferred debt issue costs are amortized over the period to maturity of the debt on a straight-line basis.

h) Workplace Safety and Insurance Act

The Corporation is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act ["WSIA"]. As a Schedule 1 employer, the Corporation is required to pay annual premiums into an insurance fund established under the WSIA and recognizes expenses based on funding requirements.

i) Revenue recognition and accounting for financial derivative instruments

LDC

Revenue from the sale of electricity is recorded on a basis of cyclical billings and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39,800,000. The rate increase was effective as of April 1, 2005 and is subject to a financial commitment by LDC to spend $39,800,000 in CDM activities by September 2007. The revenue of $39,800,000 was billed to customers over a period of 11-months commencing April 1, 2005. At each reporting date, on a life-to-date basis, to the extent the earned customer revenue exceeds the CDM activity spending, the difference is recorded in the balance sheet as "Deferred revenue".

Other income, which includes revenues from electricity distribution related services, is recognized as the services are rendered.

TH Energy

TH Energy has entered into contracts to provide electricity at fixed prices. Electricity contracts are contracts with fixed notional volumes at fixed prices. These contracts expose TH Energy to changes in market prices of electricity and consumption. To reduce its exposure to these changes, TH Energy purchases wholesale electricity physical bilateral and financial contracts.

TH Energy accounts for notional block contracts and non-designated purchase contracts using the mark-to-market method of accounting. Under the mark-to-market method of accounting, TH Energy records the fair value of the contracts, less related reserves, as mark-to-market assets or liabilities at the time of contract execution. All transactions are recognized on a net basis as mark-to-market revenue. Mark-to-market revenue includes gains or losses on new transactions at origination, unrealized gains and losses from changes in the fair value of contracts, net gains or losses from realized transactions and changes in reserves.

TH Energy records reserves for counter-party credit risk and on-going operational expense to reflect uncertainties associated with certain estimates inherent in the determination of the fair value of mark-to-market assets and liabilities. To the extent possible, TH Energy utilizes market-based data together with quantitative methods to determine the level of reserves.

As at December 31, 2006, all retail and wholesale electricity contracts have concluded. TH Energy has no outstanding contracts as at December 31, 2006.

Energy efficiency products and services revenue is accounted for under the percentage of completion method, with revenue recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident.

Water heater revenue is accounted for when the service is rendered.

TH Energy provides certain services to the City at commercial rates, including street lighting and expressway lighting services. Street lighting and expressway lighting services are recognized when services are rendered.

Telecom

Fibre leasing and data communications services revenues are recognized as services are rendered.

j) Employee future benefits

Pension plan

The Corporation provides a pension plan for its full-time employees through Ontario Municipal Employees Retirement System ["OMERS"]. OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Corporation recognizes the expense related to this plan as contributions are made.

Employee future benefits other than pension

Employee future benefits other than pension provided by the Corporation include medical and life insurance benefits, accumulated sick leave credits and voluntary exit incentive program liability. These plans provide benefits to employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render services on an accrual basis.

The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains (losses) over 10% of the accrued benefit obligation are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in the period in which a settlement occurs.

k) Customers' advance deposits

Customers' advance deposits are cash collections from customers to guarantee the payment of energy bills. The customers' advance deposits liability includes interest credited to the customers' deposit accounts, with the debit charged to interest expense. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

l) Asset retirement obligations

The Corporation recognizes a liability for the future environmental remediation of certain properties and for future removal and handling costs for contamination in distribution equipment and in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is depreciated and the liability is adjusted quarterly for the discount applied upon initial recognition of the liability ["accretion expense"] and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ["ARO"] is incurred and when the fair value is determined.

Effective June 30, 2006, the Corporation adopted Emerging Issues Committee Abstract EIC-159 "Conditional Asset Retirement Obligations" ["EIC-159"]. EIC-159 requires an entity to recognize a liability for the fair value of an ARO even though the timing or method of settlement is conditional on future events. The Corporation has identified

conditional AROs and recognized the related liability in 2006. The adoption has been accounted for prospectively as information is not available to allow it to be accounted for retroactively. The fair value of the identified AROs and the change from prior period are determined to be not material to the Corporation's result of operations and financial position.

m) Use of estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or Minister of Finance.

5. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2006			2005		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Land	**4,088**	**—**	**4,088**	4,136	—	4,136
Buildings	**145,281**	**44,016**	**101,265**	144,048	43,332	100,716
Stations	**191,833**	**99,988**	**91,845**	183,155	94,179	88,976
Distribution lines	**2,069,674**	**1,024,020**	**1,045,654**	1,982,918	942,109	1,040,809
Transformers	**493,878**	**264,308**	**229,570**	471,562	247,102	224,460
Meters	**131,886**	**80,032**	**51,854**	127,468	75,721	51,747
Other capital assets	**44,077**	**30,127**	**13,950**	57,506	41,722	15,784
Communications	**73,041**	**45,629**	**27,412**	61,241	39,290	21,951
Computer hardware	**39,511**	**35,237**	**4,274**	36,593	33,436	3,157
Rolling stock	**57,237**	**44,243**	**12,994**	51,424	40,990	10,434
Equipment and tools	**33,168**	**23,488**	**9,680**	28,086	22,232	5,854
Construction in progress	**64,282**	**—**	**64,282**	56,717	—	56,717
	3,347,956	**1,691,088**	**1,656,868**	3,204,854	1,580,113	1,624,741

At December 31, 2006, spare transformers with carrying amounts of $5,486,000 [2005 - $4,767,000], are included in "Property, plant and equipment, net" *[note 4[b] "Spare transformers"]*. In the absence of rate regulation, inventory would have been $5,486,000 higher [2005 - $4,767,000].

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

6. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2006			2005		
	Cost $	Accumulated amortization $	Net book value $	Cost $	Accumulated amortization $	Net book value $
Land rights	**10,229**	**2,022**	**8,207**	10,074	1,819	8,255
Computer software	**118,861**	**86,070**	**32,791**	97,590	72,840	24,750
Leasehold improvements	**693**	**215**	**478**	1,239	383	856
Capital contributions	**2,043**	**197**	**1,846**	2,043	116	1,927
Software in development	**5,944**	**—**	**5,944**	6,138	—	6,138
	137,770	**88,504**	**49,266**	117,084	75,158	41,926

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets consist of the following:

	2006 $	2005 $
Regulatory assets recovery account	**37,510**	55,408
Excess of cash pension contributions	**—**	4,785
Excess of OEB annual cost	**—**	3,559
Smart meters	**29,018**	—
	66,528	63,752

Regulatory liabilities consist of the following:

	2006 $	2005 $
Pre-market opening line loss variance	**2,880**	2,880
Settlement variances	**7,990**	10,417
Other	**970**	—
	11,840	13,297

For the year ended December 31, 2006, LDC recovered approved regulatory assets amounts of $26,877,000 through permitted distribution rate adjustments [2005 - $24,563,000]. These recovery amounts are for the recovery of approved regulatory assets recorded in reporting periods prior to January 1, 2005. In accordance with the OEB's direction, the Corporation recorded carrying charges on the recovered amounts of $nil in 2006 [2005 - $1,544,000].

In the absence of rate regulation, interest income for the year ended December 31, 2006 would have been $nil [2005 - higher by $1,544,000].

For the years ended December 31, 2006 and December 31, 2005, recovery amounts were credited directly to reduce the regulatory assets recovery account. The regulatory assets and liabilities balances of the Corporation are defined as follows:

[a] Regulatory assets recovery account

On March 31, 2005, the OEB ordered that the approved regulatory asset balances be aggregated into a single regulatory account. Approved regulatory assets of $71,465,000 consisted of transition costs of $37,868,000, pre-market opening energy electricity variance of $26,129,000, and settlement variances of $31,852,000, less recoveries of $24,384,000, which were transferred to the "regulatory asset recovery account" ["RARA"]. This approved balance will be recovered over a period ending March 31, 2008. The RARA is credited with recovery amounts and is debited by OEB-prescribed carrying charges. In the absence of rate regulation, interest income in 2006 would have been $1,685,000 lower [2005 - $2,539,000].

The transition costs and pre-market opening energy electricity variance are defined as follows:

[i] Transition costs

The OEB allowed the LDC to defer the costs incurred to align systems and practices with the requirements of the competitive electricity market in Ontario in accordance with the *Ontario Energy Board Act, 1998*. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook.

Under such regulation, expenditures were allowed to be deferred during the period January 1, 2000 to December 31, 2002, which would be capitalized or expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2003 to March 31, 2005, transition costs were increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $558,000 lower.

[ii] Pre-market opening energy electricity variance

The OEB has allowed the LDC to recognize the pre-market opening energy electricity variance for the period January 1, 2001 to April 30, 2002, the date of market opening. The pre-market opening energy variance represented the difference between the LDC's cost of power purchased based upon time-of-use ["TOU"] rates and the amounts billed for the cost of power to non-TOU customers at an average rate for the same period. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. For the period January 1, 2001 to March 31, 2005, the pre-market opening energy electricity variance was increased for carrying charges in accordance with the OEB's direction. In the absence of rate regulation, interest income in 2005 would have been $370,000 lower.

[b] Excess of cash pension contributions

The OEB has allowed the LDC to defer the incremental OMERS pension expenditures for the fiscal years starting after January 1, 2005 and to end on April 30, 2006. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $6,510,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $1,725,000 higher [2005 - $4,785,000].

[c] Excess of OEB annual cost

The OEB has allowed the LDC to defer a portion of the OEB annual cost assessments for the fiscal years starting after January 1, 2004 and to end on April 30, 2006. Accordingly, the Corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

Under such regulation, the deferred expenditures would have been expensed under Canadian GAAP for unregulated businesses. In April 2006, the OEB approved the recovery of the deferred amount of $4,345,000. Accordingly, the balance was transferred to the RARA for recovery commencing May 1, 2006 and ending March 31, 2008. In the absence of rate regulation, operating expenses in 2006 would have been $786,000 higher [2005 - $2,166,000].

[d] Smart Meters

Effective May 1, 2006, the OEB has allowed the LDC to defer capital expenditures, operating expenditures, depreciation expense and revenues relating to smart meters. Accordingly, the Corporation has deferred these items in accordance with the criteria set out in the AP Handbook.

Under such regulation, in 2006, smart meter capital expenditures of $30,347,000 [2005 - $nil] were deferred. These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment in 2006 would have been $30,347,000 higher [2005 - $nil].

In 2006, smart meter operating expenditures of $526,000 [2005 - $nil] were deferred which would be expensed under Canadian GAAP for unregulated businesses., and smart meter depreciation expense of $690,000 [2005 - $nil] was deferred which otherwise would be charged to depreciation expense under Canadian GAAP for unregulated businesses. In the absence of rate regulation, operating expenses and depreciation expense in 2006 would have been $526,000 and $690,000 higher respectively [2005 - $nil and $nil respectively].

In 2006, smart meter customer revenues of $2,966,000 [2005 - $nil] were deferred. In the absence of rate regulation, revenue in 2006 would have been $2,966,000 higher [2005 - $nil].

The deferred balances continue to be calculated and attract carrying charges. In 2006, the Corporation recorded carrying charges of $422,000 [2005 - $nil] on the deferred amounts. In the absence of rate regulation, interest income in 2006 would have been $422,000 lower [2005 - $nil].

The manner and timing of disposition of these smart meter regulatory assets have not been determined by the OEB at this time.

[e] Pre-market opening line loss variance

The OEB has allowed the LDC to defer the pre-market opening line loss variance for the period June 1, 2001 to April 30, 2002. This balance represents the variance between amounts charged by LDC to customers for the OEB-approved loss adjustment factor and the LDC actual loss adjustment factor. Accordingly, the Corporation has deferred this variance in accordance with the OEB's direction.

In the absence of rate regulation, there would have been no impact on the Consolidated Statement of Income for 2006 and 2005. The deferred balance does not attract carrying charges. The manner and timing of disposition of the variance have not been determined by the OEB.

[f] Settlement variances

The OEB has allowed the LDC to defer settlement variances from May 1, 2002 to December 31, 2006. This balance represents the variances between amounts charged by LDC to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by LDC after May 1, 2002. The settlement variances relate primarily to service charges, non-competitive electricity charges, imported power charges and the global adjustment. Accordingly, the Corporation has deferred these recoveries in accordance with the criteria set out in the AP Handbook.

Settlement variances of $27,980,000, relating to the period from May 1, 2002 to December 31, 2004, were approved for recovery by the OEB and are included in the RARA balance. The remaining balance, representing settlement variances arising after January 1, 2005, is deferred in a regulatory liability account.

In the absence of rate regulation, interest income in 2006 would have been $49,000 lower [2005 - $1,112,000]. The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance have not been determined by the OEB.

8. OTHER ASSETS

Other assets consist of the following:

	2006 $	2005 $
Deferred debt issue costs, net of accumulated amortization of $1,412,000 [2005 - $1,025,000]	**2,457**	2,843
Long-term advances and deposits	**—**	1,566
Other	**121**	1,081
	2,578	5,490

9. BANK INDEBTEDNESS AND BANKERS' ACCEPTANCES

On May 5, 2005, the Corporation extended its revolving credit facility with a syndicate of Canadian banks [the "Revolving Credit Facility"] for a three-year period to May 4, 2008. Under the terms of the revolving credit facility, the Corporation may borrow up to $500,000,000, of which:

[a] $500,000,000 less the amount utilized under [b] is available for working capital purposes in the form of prime rate loans in Canadian dollars and bankers' acceptances; and

[b] up to $175,000,000 is available in the form of letters of credit to support the prudential requirements of LDC and TH Energy and general credit requirements of the Corporation and its subsidiaries.

The facility contains a negative pledge, customary covenants and events of default.

At December 31, 2006, $81,620,000 [December 31, 2005 - $90,174,000] had been utilized under the revolving credit facility in the form of letters of credit to support the prudential requirements of LDC [$80,000,000] [2005 - $80,000,000], TH Energy [$780,000] [2005 - $9,194,000] and Telecom [$840,000] [2005 - $980,000]. At December 31, 2006, no amounts had been drawn for working capital purposes [December 31, 2005 - $nil].

The Corporation also has a bilateral demand line of credit for $20,000,000 with a Canadian chartered bank. The line of credit bears interest at the bank's prime rate [December 31, 2006 – 6%]. At December 31, 2006, no amounts had been drawn on the line of credit [December 31, 2005 - $nil].

10. CURRENT PORTION OF OTHER LONG-TERM LIABILITIES

Current portion of other long-term liabilities consist of the following:

	2006 $	2005 $
Current portion of obligations under capital leases *[note 20]*	**733**	1,877
Customers' advance deposits	**15,904**	37,029
Other	**315**	304
	16,952	39,210

11. LONG-TERM DEBT

Long-term debt consists of the following:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

	2006 $	2005 $
Senior unsecured debentures	**225,000**	225,000
Promissory note payable to the City	**980,231**	980,231
	1,205,231	1,205,231
Less: Current portion of promissory note payable to the City	**245,058**	330,000
Long-term debt	**960,173**	875,231
Comprising:		
Debentures	**225,000**	225,000
Promissory note payable to the City	**735,173**	650,231

All debt of the Corporation ranks equally.

a) Senior unsecured debentures

On May 7, 2003, the Corporation issued $225,000,000 10-year senior unsecured debentures. The Corporation's 10-year senior unsecured debentures in the amount of $225,000,000, as at December 31, 2006, [December 31, 2005 - $225,000,000] bear interest at a rate of 6.11% per annum, payable semi-annually in arrears in equal instalments on May 7 and November 7 of each year. The debentures mature on May 7, 2013.

The Corporation may redeem some or all of the debentures at any time prior to maturity at a price equal to the greater of the Canada Yield Price (determined in accordance with the terms of the debentures) and par, plus accrued and unpaid interest up to but excluding the date fixed for redemption. Also, the Corporation may, at any time and from time to time, purchase debentures for cancellation, in the open market, by tender or by private contract, at any price. The debentures have the benefit of certain covenants which, subject to certain exceptions, restrict the ability of the Corporation and LDC to create security interests, incur additional indebtedness or dispose of all or substantially all of their assets.

b) Promissory note payable to the City of Toronto

LDC issued a promissory note to the City on July 1, 1999 ["Initial Note"] in the principal amount of $947,000,000 in partial consideration for the assets in respect of the electricity distribution system transferred by the Toronto Hydro-Electric Commission and the City to LDC effective July 1, 1999. The Initial Note was non-interest bearing until December 31, 1999 and interest bearing thereafter at the rate of 6% per annum. Pursuant to the Transfer By-law, the principal amount of the Initial Note was adjusted effective January 1, 2000 to $980,231,000 to reflect the deemed debt to equity structure of LDC [65:35] permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note ["Replacement Note"] issued by LDC, which was interest bearing at the rate of 6.8% per annum. At December 31, 2002, the Replacement Note was payable on the earlier of demand and December 31, 2003.

Concurrent with the closing of the debenture offering on May 7, 2003, the City transferred the Replacement Note to the Corporation in consideration for the issue by the Corporation to the City of a new promissory note in the

principal amount of $980,231,000 [2005 – $980,231,000] [the "City Note"]. At December 31, 2005 the principal amount of the City Note, together with accrued interest thereon, was payable:

[a] on demand on not less than 90 days written notice until May 7, 2006; and

[b] in accordance with a payment schedule to be delivered by the City at least 90 days before May 7, 2006;

provided that the Corporation will not be required to pay more than $330,000,000 of the principal amount of the City Note during any twelve-month period. Accordingly, $330,000,000 of the principal amount outstanding under the City Note was classified as a current liability. In 2005 the maximum term of the City Note was ten years.

On September 5, 2006, the Corporation announced that it and the City had amended and restated the City Note effective May 1, 2006 by fixing the interest rate at 6.11% and establishing an agreed repayment schedule. The Corporation is required to pay the principal amount of the note as follows: $245,058,000 on the last business day before each of December 31, 2007, December 31, 2009, December 31, 2011 and on May 6, 2013. Accordingly, $245,058,000 of the principal amount outstanding under the City Note is classified as a short-term liability, with the remainder being classified as a long-term liability. Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year.

12. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2006, the Corporation's OMERS current service pension costs were $10,343,000 [2005 - $8,965,000].

Employee future benefits other than pension

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits [excluding pension] to most of its employees. The Corporation pays certain medical and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees. The Corporation pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

The Corporation measures its accrued benefits obligation for accounting purposes as at December 31 of each year. The latest actuarial valuation was performed as at January 1, 2005. The December 31, 2006 year-end accrued benefit obligation reflects a December 31, 2006 discount rate. This result was achieved by updating the January 1, 2005 actuarial valuation using the December 31, 2006 discount rate of 5.3% while keeping all other assumptions constant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

[a] Accrued benefit obligation

	2006 $	2005 $
Balance at beginning of year	**167,013**	139,468
Experience gain at beginning of year	—	(1,446)
Current service cost	**3,907**	3,152
Interest cost	**8,412**	8,178
Benefits paid	**(5,372)**	(4,988)
Actuarial (gains) losses	**(6,499)**	22,649
Balance at end of year	**167,461**	167,013

[b] Reconciliation of the accrued benefit obligation to the balance sheet accrued benefits liability

	2006 $	2005 $
Accrued benefit obligation	**167,461**	167,013
Unamortized net actuarial loss	**(26,593)**	(34,427)
Unamortized past service costs	**(6,186)**	(7,171)
Post-employment benefits liability	**134,682**	125,415

[c] Components for net periodic defined benefit costs

	2006 $	2005 $
Current service cost	**3,907**	3,152
Interest cost	**8,412**	8,178
Actuarial (gains) losses	**(6,499)**	21,203
Cost incurred in the year	**5,820**	32,533
Differences between costs incurred and costs recognized in the year in respect of:		
Actuarial loss (gain)	**7,789**	(21,230)
Past service costs	**985**	983
	8,774	(20,247)
Defined benefit costs recognized	**14,594**	12,286
Capitalized as part of property, plant and equipment	**6,385**	3,672
Charged to operations	**8,209**	8,614

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

[d[Significant assumptions

	2006 %	2005 %
Accrued benefit obligation as of December 31:		
Discount rate	**5.3**	5.0
Rate of compensation increase	**4.0**	4.0
Benefit costs for years ended December 31:		
Discount rate	**5.0**	5.9
Rate of compensation increase	**4.0**	4.0
Assumed health care cost trend rates at December 31:		
Rate of increase in dental costs	**4.5**	4.5

For December 31, 2006 and 2005, medical costs are assumed to increase at 10.5% graded down by 1.0% annual decrements to 4.5% in 2011 and thereafter.

[e] Sensitivity analysis

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates have the following effects for 2006:

	Increase $	Decrease $
Net periodic benefit cost (at 5.0%)	**2,282**	**(1,699)**
Accrued benefit obligation at December 31, 2006 (at 5.3%)	**27,682**	**(21,182)**

13. OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following:

	2006 $	2005 $
Obligations under capital leases *[note 20]*	**1,033**	2,063
Security deposits	**1,575**	3,277
Lease liability – long-term	**—**	285
Other	**1,341**	3,452
	3,949	9,077

During 2006, the Corporation acquired "Property, plant and equipment" through capital lease transactions totaling $556,000 [2005 - $43,000]. These non-cash transactions have been excluded from the Consolidated Statement of Cash Flows.

14. ASSET RETIREMENT OBLIGATIONS

A reconciliation between the opening and closing ARO liability balances is as follows:

	2006 $	2005 $
Balance, beginning of year	**5,691**	4,274
ARO liabilities incurred in the year	**2,039**	1,525
ARO liabilities settled in the year	**(509)**	(351)
Accretion expense	**360**	243
Balance, end of year	**7,581**	5,691

At December 31, 2006, the Corporation estimates the undiscounted amount of cash flows required over the next ten years to settle the ARO is $11,372,000 [2005 - $6,836,000]. Discount rates ranging from 4.3% to 6.0% were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

15. FINANCIAL INSTRUMENTS

Electricity retailing commitments

In December 2002, TH Energy ceased new electricity retailing activities in respect of new customers as a result of the price freeze implemented under Bill 210. TH Energy managed the remaining portfolio of electricity contracts comprised primarily of fixed notional volume contracts, wholesale financial fixed notional volume fixed-for-floating and floating-for-fixed swaps and fixed notional volume physical bilateral contracts. The contracts are derivative contracts for accounting purposes. The electricity contracts had varying maturity dates throughout the period ending December 31, 2006.

At December 31, 2006, TH Energy had floating-for-fixed electricity contracts that had an aggregate expected contract volume and value of nil MWh and $nil [2005 – 3,124,000 MWh and $171,270,000].

To hedge the volume and price risk inherent in retailing electricity, TH Energy entered into financial fixed notional volume fixed-for-floating swaps and fixed notional physical bilateral contracts with generators and marketers. At December 31, 2006, the aggregate notional volume and value of these contracts were nil MWh and $nil [2005 – 3,614,000 MWh and $154,396,000].

For the year ended December 31, 2006, "Revenues" include $20,661,000 of electricity mark-to-market revenues [2005 - $34,309,000].

Credit risk

Financial instruments result in exposure to credit risk stemming from the risk of the counter-party defaulting on its obligations. TH Energy monitors and limits its exposure to counter-parties with lower credit ratings and evaluates its counter-party credit exposure on a continuous basis. TH Energy obtains collateral from some counter-parties and seeks to deal only with counter-parties with investment-grade credit ratings. TH Energy had five wholesale counter-parties as at December 31, 2006 for its electricity supply portfolio. In addition, TH Energy provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties. The largest single credit exposure at December 31, 2006 is estimated at $12,382,389, which is the December 2006 invoice of power sold to one counter party [2005 - $137,170,000].

For retail customers, credit losses are generally low across the sector. LDC, TH Energy and Telecom provide for an allowance for doubtful accounts to absorb credit losses. At December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets other than the risk mentioned above.

Interest rate risk

The Corporation is exposed to interest rate risk for certain of its financial assets and liabilities. Under the Corporation's Revolving Credit Facility *[note 9]*, the Corporation may have short-term borrowings for working capital purposes. These borrowings would expose the Corporation to fluctuations in short-term interest rates [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on a margin determined by reference to the Corporation's credit rating.

Certain cash balances of the Corporation is invested in Canadian money market instruments, with terms of one day to 90 days, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Fair value of financial instruments

The carrying value of cash and cash equivalents, accounts receivable, unbilled revenue, and accounts payable and accrued liabilities approximates their fair value due to the immediate or short-term maturity of these financial instruments**.**

At December 31, 2006, the fair values of the City Note [$980,231,000] and the senior unsecured debentures [$225,000,000] are $1,034,640,000 and $247,515,000 [2005 - $1,120,405,000 and $251,415,000]. These fair values have been calculated by discounting the future cash flow of the respective long-term debt at the estimated yield to maturity of similar debt instruments *[note 11]*.

The fair value of hedging derivative financial instruments is the estimated amount the Corporation would receive (pay) to terminate the contracts. The value is based on market prices or management's best estimates if there is no organized market and/or if the market is illiquid.

All retail fixed notional volume fixed price contracts and all undesignated wholesale fixed notional volume fixed-for-floating swaps and fixed notional volume physical bilateral contracts are accounted for using the mark-to-market method of accounting. The following are the primary sources of the change in the net mark-to-market assets:

	2006 $	2005 $
Net mark-to-market assets		
Fair value, beginning of year	**26,422**	27,696
Unrealized change in fair value during the period	**(4,431)**	16,342
Realization of contracts for the period	**(21,991)**	(17,616)
Fair value of net mark-to-market assets, end of year	**—**	26,422

16. FINANCIAL GUARANTEES

Participants [including LDC and TH Energy] in the wholesale market for electricity are required to satisfy prescribed prudential requirements. In addition, counter-parties under contracts for the purchase and sale of electricity and customers under purchase contracts may require parental financial guarantees or other forms of credit support.

The City has authorized the Corporation to provide up to $500,000,000 in financial support [including guarantees] with respect to prudential requirements and as security for obligations under third party contracts.

At December 31, 2006, the Corporation's board of directors had approved $386,000,000 in parental guarantees on behalf of TH Energy, of which $56,500,000 has been issued to unrelated parties [2005 - $86,500,000].

The Corporation has issued a parental guarantee to the City as part of an agreement to purchase electricity at a fixed price from TH Energy. The fair value of the parental guarantee was $nil at December 31, 2006 [2005 - $56,417,000]

17. PAYMENTS IN LIEU OF CORPORATE TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. Reconciliation between the statutory and effective tax rates is set out below:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Consolidated Statement of income

	2006 $	2005 $
Rate reconciliation		
Income before PILs	**148,622**	159,756
Consolidated Statutory Canadian federal and provincial income tax rate	**36.12%**	36.12%
Expected provision for PILs	**53,682**	57,704
Increase in income taxes resulting from large corporations tax net of surtax	**—**	1,655
Temporary differences not benefited	**3,482**	10,630
Valuation allowance	**1,150**	(2,056)
Decrease in federal future tax rates	**2,215**	—
Other	**(2,126)**	906
Provision for PILs	**58,403**	68,839
Effective tax rate	**39.30%**	43.09%
Components of provision for PILs		
Current tax provision	**60,890**	71,960
Future income tax recovery related to the origination and reversal of temporary differences	**(2,487)**	(3,121)
Provision for PILs	**58,403**	68,839

Consolidated Balance sheet

Significant components of the Corporation's future income tax assets and liabilities are as follows:

	2006 $	2005 $
Non-capital loss carryforwards	**576**	2,785
Property, plant and equipment and intangible assets	**27,968**	32,153
Other taxable temporary differences	**4,735**	(4,998)
Valuation allowance	**(16,847)**	(15,973)
	16,432	13,967

Presented on the consolidated balance sheet as follows:

	2006 $	2005 $
Future income tax assets, current	**791**	33,195
Future income tax assets, long-term	**16,009**	22,264
Future income tax liabilities, current	**—**	(40,923)
Future income tax liabilities, long-term	**(368)**	(569)
	16,432	13,967

Under the taxes payable method applicable to LDC, no adjustments are made for differences between the financial statement carrying values and the tax basis of assets and liabilities. As at December 31, 2006, future income tax assets of $234,217,000 [2005 - $249,838,000], based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Corporation's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs in 2006 would have been $3,482,000 lower [2005 – $7,863,000 lower][*note 4 [b]*].

As at December 31, 2006, the Corporation has accumulated tax losses for PILs purposes of approximately $1,744,000, which are available to reduce future years' taxable income. These loss carryforwards begin to expire in 2008.

As at December 31, 2006, LDC has accumulated a PILs variance amount, representing the difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs, totaling an under-recovery of $10,286,000 [2005 -$4,948,000]. LDC has also accumulated a PILs variance amount representing differences that have resulted from a legislative or regulatory change to the tax rates or rules assumed in the 2006 electricity distribution rate application totalling an over-recovery of $1,702,000 [2005 - $ nil]. Cumulative interest included in the amounts was calculated following OEB direction and totaled $3,004,000 [2005 - $2,858,000].

18. SHARE CAPITAL

Share capital consists of the following:

	2006 $	2005 $
Authorized		
The authorized share capital of the Corporation consists of an unlimited number of common shares		
Issued and outstanding		
1,000 common shares	**567,817**	567,817

Dividends

The shareholder direction adopted by the City with respect to the Corporation provided that the Corporation's board of directors would use its best efforts to ensure that the Corporation met certain financial performance standards, including those relating to credit rating and dividends. Subject to applicable law, the shareholder direction provided that the Corporation would pay dividends to the City each year.

Subject to applicable law and the shareholder direction, the amount of the annual dividends payable by the Corporation to the City is to be the greater of $25,000,000 or 50% of the Corporation's annual consolidated net income. The dividends are not cumulative and are payable as follows:

[a] $6,000,000 on the last day of each of the first three fiscal quarters in each year;

[b] $7,000,000 on the last day of the fiscal year; and

[c] the amount, if any, by which 50% of the Corporation's annual consolidated net income for the year exceeds $25,000,000 within ten days after the board of directors of the Corporation approves the Corporation's audited consolidated financial statements for the year.

During 2006, the board of directors of the Corporation declared and paid dividends totaling $46,200,000 to the City [2005 - $68,000,000].

19. RELATED PARTIES

For the Corporation, transactions with related parties include transactions with the City. All transactions with the City are conducted at prevailing market prices and normal trade terms.

For the year ended December 31, 2006, LDC provided street lighting electricity to the City in the amount of $9,281,000 [2005 - $11,089,000].

For the year ended December 31, 2006, TH Energy invoiced the City for electricity for $102,771,000 [2005 - $107,450,000]. At December 31, 2006, included in "Accounts receivable, net of allowance for doubtful accounts" are $5,905,000 [2005 - $1,257,000] receivable from the City related to these electricity billing activities.

For the year ended December 31, 2006, TH Energy provided energy efficiency products and services to the City amounting to $2,010,000 [2005 - $1,927,000].

On December 31, 2005, TH Energy acquired the street lighting and expressway lighting assets from the City for cash consideration of $60,000,000. The transaction was recorded at the exchange amount, which is reflective of the fair market value, as an increase in property, plant and equipment. The acquisition of these assets was recorded at the exchange amount since the carrying value of the assets in the City's records was not determinable. The purchase price was supported by an independent valuation of the fair market value of the acquired assets. The acquired assets are being depreciated over their estimated remaining service lives.

Concurrently with the transaction, the Corporation entered into a service agreement with the City to provide street lighting and expressway lighting services to the City for a period of 30 years commencing January 1, 2006. During

2006, TH Energy provided street and expressway lighting services to the City totalling $15,287,000 [2005 - $4,712,000].

For the year ended December 31, 2006, LDC incurred property taxes payable to the City of $7,306,000 [2005 - $7,030,000].

At December 31, 2006, a promissory note in the amount of $980,231,000 [2005 - $980,231,000] was payable to the City. For the year ended December 31, 2006, interest expense of $59,892,000 [2005 - $66,656,000], on the promissory note was paid to the City *[note 11]*.

20. LEASE COMMITMENTS

Operating lease obligations

As at December 31, 2006, the future minimum annual lease payments under property and computer hardware operating leases with remaining lease terms from one to five years are as follows:

	$
2007	**4,646**
2008	**5,793**
2009	**5,567**
2010	**5,498**
2011	**5,018**
Thereafter	**2,953**
Total minimum lease payments	**29,475**

Capital lease obligations

As at December 31, 2006, the future minimum annual lease payments under vehicle capital leases with remaining lease terms from one to five years are as follows:

	$
2007	**733**
2008	**562**
2009	**552**
2010	**160**
Thereafter	**11**
Total amount of future minimum lease payments	**2,018**
Less interest	**252**
	1,766
Current portion *[note 10]*	**733**
Long-term portion *[note 13]*	**1,033**

21. CONTINGENCIES

a) Ministry of Finance Tax Audit

The Ministry of Finance is currently carrying out a tax audit on the Corporation and its subsidiaries. Certain filing positions for PILs taken by the Corporation and its subsidiaries may be challenged on the audit. This may result in a material increase in the Corporation's reported tax obligations upon reassessment. As the audit has not yet been completed, management is not able to determine the impact, if any, of the audit on the consolidated financial statements or the Corporation's tax reserves. The Corporation adjusts its tax reserves when there is sufficient information available, or when an event occurs requiring a change to the reserves.

b) Consumers' Gas Decision

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada [the "Supreme Court"] ruled that The Consumers' Gas Company ["Consumers' Gas"] was required to repay the portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the *Criminal Code* in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement, however, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff, and to receive lawyer's fees in connection with that effort. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario municipal electric utilities under the Class Proceedings Act, 1992 seeking $500,000,000 in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intention to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the Class Proceedings Act, 1992 seeking $64,000,000 in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the *Criminal Code*. This action is also at the preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the *Criminal Code* is fact specific in each circumstance. Accordingly, given the preliminary status of these actions, it is not possible at this time to quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

22. NET INCOME PER SHARE

The weighted daily average numbers of shares outstanding were 1,000 as at December 31, 2006 and 2005, for purposes of determining basic and fully diluted net income per share for continuing and discontinued operations. Basic and fully diluted net income per share for continuing and discontinued operations were determined by dividing the net income for the year by the weighted daily average number of shares outstanding.

23. DISCONTINUED OPERATIONS

In November 2006, the Board of Directors of TH Energy approved a plan to sell the water heater assets and to exit this business segment. Accordingly, the results of operations and financial position of the water heater business have been segregated and presented as discontinued operations in the accompanying financial statements. As at December 31, 2006, the net assets of the water heater business have been measured and presented at the lower of the carrying amount or fair value less cost to sell. The net assets held for sale are as follows:

	$
Current assets held for sale:	
Property, plant and equipment	**12,098**
	12,098
Current liabilities held for sale:	
Accounts payable	**103**
Future income tax liabilities	**803**
	906

For the year ended December 31, 2006 and 2005, the following revenue and expenses of the water heater business have been reclassified from continuing operations to discontinued operations:

	2006 $	2005 $
Sales	**8,085**	8,147
Expenses		
Purchased power and other	**1,820**	1,753
Operating expenses	**879**	319
Depreciation and amortization	**2,405**	3,498
	5,104	5,570
Provision of payments in lieu of corporate taxes	**803**	1,049
Income from discontinued operations	**2,178**	1,528

24. SEGMENT REPORTING

The designation of the segments has been based on a combination of the regulatory status and the nature of products and services provided. The Corporation has two reportable segments:

[a] Electricity Distribution:
the regulated business which consists of the electricity distribution business of LDC; and

[b] Non-regulated:
the non-regulated business of TH Energy which consist primarily of the delivery of street lighting and expressway lighting services, the sale of energy management services, and up until December 31, 2006, the management of a portfolio of electricity contracts. The non-regulated business of Telecom which consists of the provision of fibre optic capacity and data communications services to telecommunications carriers, business customers and large institutions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Segment information on the above basis is as follows:

	2006 $	2005 $
Electricity Distribution		
Revenues	**2,264,469**	2,709,819
Purchased power and other	**1,784,144**	2,224,034
Depreciation and amortization	**124,560**	124,988
Interest income	**11,225**	10,485
Interest expense	**76,537**	80,620
Segment profit before interest, other items and provision for payments in lieu of corporate taxes	**186,701**	193,658
Payment in lieu of corporate taxes	**46,001**	61,114
Non-regulated		
Revenues	**75,530**	103,434
Purchased power and other	**14,654**	42,331
Depreciation and amortization	**12,784**	6,607
Interest income	**84,520**	81,865
Interest expense	**80,278**	80,717
Segment profit before interest, other items and provision for payments in lieu of corporate taxes	**22,902**	30,045
Payment in lieu of corporate taxes	**12,402**	7,725
Intersegment eliminations		
Revenues	**(92,991)**	(206,981)
Purchased power and other	**(92,953)**	(206,576)
Interest income	**(78,019)**	(78,234)
Interest expense	**(78,019)**	(78,234)

	2006 $	2005 $
Total		
Revenues	**2,247,008**	2,606,272
Purchased power and other	**1,705,845**	2,059,789
Depreciation and amortization	**137,344**	131,595
Interest income	**17,726**	14,116
Interest expense	**78,796**	83,103
Income before interest, other items and provision for payments in lieu of corporate taxes	**209,603**	223,703
Payment in lieu of corporate taxes	**58,403**	68,839

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

	2006 $	2005 $
Expenditures on property, plant and equipment and intangible assets		
Electricity Distribution	**167,685**	132,260
Non-regulated	**22,934**	68,095
Intersegment eliminations	**(5,312)**	—
Total	**185,307**	200,355

	2006 $	2005 $
Assets		
Electricity Distribution	**2,280,811**	2,393,533
Non-regulated	**1,505,987**	1,619,790
Intersegment eliminations	**(1,207,190)**	(1,194,065)
Discontinued operations	**12,098**	—
Total	**2,591,706**	2,819,258

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. COMPARATIVE CONSOLIDATED FINANCIAL STATEMENTS

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the 2006 consolidated financial statements.

26. SUBSEQUENT EVENTS

Regulatory Affairs

On January 26, 2007, LDC filed an Annual Rate Adjustment Application for 2007 Rates as directed to by the OEB. In accordance with the OEB's Incentive Regulation Model, LDC has sought authorization to increase its rates by 0.4% on May 1, 2007.

Sale of water heater business

On February 8, 2007, TH Energy sold its water heater business to Consumers' Waterheater Income Fund for cash consideration of $40,800,000 subject to post closing adjustments and transaction costs. This transaction will be recorded in the financial statements in 2007.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
[all tabular amounts in thousands of dollars]

December 31, 2006

Dividends

On March 1, 2007, the board of directors of the Corporation declared a dividend in the amount of $27,199,000. The dividends are comprised of a $21,199,000 payment for 2006 net income, payable to the City on March 9, 2007 and a $6,000,000 payment in connection with the first quarter of 2007, payable to the City on March 30, 2007.

ANNEX B
MANAGEMENT'S DISCUSSION AND ANALYSIS
OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ANNEX B

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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TORONTO HYDRO CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS FOR THE YEAR ENDED DECEMBER 31, 2006

The following discussion and analysis should be read in conjunction with the audited consolidated financial statements and accompanying notes of Toronto Hydro Corporation (the "Corporation") as at and for the year ended December 31, 2006 (the "Consolidated Financial Statements"). The Consolidated Financial Statements are prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed by the Ontario Energy Board (the "OEB") and are presented in Canadian dollars.

Business of Toronto Hydro

The Corporation is a holding company, which wholly-owns the following subsidiaries:

- *Toronto Hydro-Electric System Limited* ("LDC") – which distributes electricity;

- *Toronto Hydro Energy Services Inc.* ("TH Energy") – which provides street lighting and expressway lighting services and develops energy efficiency products and services. In 2006, TH Energy also managed a portfolio of electricity contracts (the last of which expired on December 31, 2006), and operated a water heater rental business (the assets comprising the water heater rental business were sold on February 8, 2007). See notes 15, 23 and 26 to the Consolidated Financial Statements; and

- *Toronto Hydro Telecom Inc.* ("Telecom") – which provides fibre optic cable capacity and manages data communications services.

The principal business of the Corporation and its subsidiaries is the distribution of electricity by LDC. LDC owns and operates an electricity distribution system, which delivers electricity to approximately 678,000 customers located in the City of Toronto. LDC is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in Ontario. The business of LDC is regulated by the OEB which has broad powers relating to licensing, standards of conduct and service and the regulation of rates charged by LDC and other electricity distributors in Ontario.

TH Energy owns and operates street lighting and expressway lighting systems located in the City of Toronto and is engaged in the sale of energy efficiency products and services to commercial and industrial customers.

Telecom is a provider of "dark" fibre optic capacity and data communications services to telecommunications carriers, business customers and large institutions in the City of Toronto. Telecom owns a network of fibre optic cable located in ducts, on poles and in other parts of the electricity distribution system of LDC. The network is currently connected to over 490 buildings located in the City of Toronto.

The sole shareholder of the Corporation is the City of Toronto (the "City").

Electricity Distribution – Industry Overview

On May 1, 2002, the Province opened Ontario's wholesale and retail markets to competition by providing generators, retailers and consumers with open access to Ontario's transmission and distribution network ("Open Access").

Since the commencement of Open Access, LDC and other electricity distributors have been purchasing their electricity from the wholesale market administered by the Independent Electricity System Operator ("IESO") and recovering the costs of electricity and certain other costs at a later date in accordance with procedures mandated by the OEB.

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The *Ontario Energy Board Act, 1998* sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that electricity distribution companies fulfil obligations to connect and service customers.

LDC is required to charge its customers for the following amounts (all of which, other than the distribution rate, represent a pass through of amounts payable to third parties):

- *Electricity Price and Related Rebates* – The electricity price and related rebates represent a pass through of the commodity cost of electricity.

- *Distribution Rate* – The distribution rate is designed to recover the costs incurred by LDC in delivering electricity to customers and the OEB-allowed rate of return. Distribution rates are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.

  The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally, sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

- *Retail Transmission Rate* – The retail transmission rate represents a pass through of wholesale costs incurred by distributors in respect of the transmission of electricity from generating stations to local areas. Retail transmission rates are regulated by the OEB.

- *Wholesale Market Service Charge* – The wholesale market service charge represents a pass through of various wholesale market support costs. Retail rates for the recovery of wholesale market service charges are regulated by the OEB.

Market participants (including distributors and retailers) are required to satisfy and maintain prudential requirements with the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings.

The Corporation and its subsidiaries are exempt from tax under the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)*, if not less than 90% of the capital of the Corporation is owned by the City and not more than 10% of the income of the Corporation and each of its subsidiaries is derived from activities carried on outside the municipal geographical boundaries of the City.

The Corporation and each of its subsidiaries is a "municipal electricity utility" ("MEU") for purposes of the payment in lieu of corporate taxes ("PILs") regime contained in the *Electricity Act, 1998*. The *Electricity Act, 1998* provides that a MEU that is exempt from tax under the *Income Tax Act (Canada)* and the *Corporations Tax Act*

(Ontario) is required to make, for each taxation year, a PILs to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)* if it were not exempt from tax.

Selected Consolidated Financial Data

The selected consolidated financial data presented below should be read in conjunction with the Consolidated Financial Statements.

Year ended December 31, (in thousands of dollars, except for per share amounts)	2006 $	2005 $	Change $	Change %
Consolidated Statement of Operations Data [1]				
Revenues	2,247,008	2,606,272	(359,264)	(13.78%)
Costs				
Purchased power and other	1,705,845	2,059,789	(353,944)	(17.18%)
Operating expenses	194,216	191,185	3,031	1.59%
Depreciation and amortization	137,344	131,595	5,749	4.37%
	2,037,405	2,382,569	(345,164)	(14.49%)
Income before interest, other and provision for PILs	209,603	223,703	(14,100)	(6.30%)
Interest income	17,726	14,116	3,610	25.57%
Interest expense				
Long-term debt	(75,894)	(80,403)	4,509	5.61%
Other interest	(2,902)	(2,700)	(202)	(7.48%)
Other	89	5,040	(4,951)	(98.23%)
Income before provision for PILs	148,622	159,756	(11,134)	(6.97%)
Provision for PILs	58,403	68,839	(10,436)	(15.16%)
Income from continuing operations	90,219	90,917	(698)	(0.77%)
Income from discontinued operations – net of tax [2]	2,178	1,528	650	42.54%
Net income	92,397	92,445	(48)	(0.05%)
Basic and fully diluted net income per share from continuing operations	90,219	90,917	(698)	(0.77%)
Basic and fully diluted net income per share from discontinued operations	2,178	1,528	650	42.54%
Basic and fully diluted net income per share	92,397	92,445	(48)	(0.05%)

Notes:

(1) Amounts reflect reclassification for discontinued operations. See note 23 to the Consolidated Financial Statements.
(2) Consists of discontinued operations for water heaters. See note 23 to the Consolidated Financial Statements.

As at December 31, (in thousands of dollars)	2006 $	2005 $
Consolidated Balance Sheet Data [1]		
Total assets	2,591,706	2,819,258
Current liabilities	555,105	941,211
Long-term liabilities	1,144,537	1,032,180
Total liabilities	1,699,642	1,973,391
Shareholder's equity	892,064	845,867
Total liabilities and shareholder's equity	2,591,706	2,819,258

Note:

(1) Includes discontinued operations. See note 23 to the Consolidated Financial Statements.

Results of Operations

Net Income

Net income was $92.4 million in 2006 and 2005. Unfavourable variances were noted in net revenues ($5.3 million), operating expenses ($3.0 million), depreciation and amortization expense ($5.7 million) and other ($5.0 million). These unfavourable variances were offset by decreased net interest expense ($7.9 million), decreased provision for PILs ($10.4 million) and increased income from discontinued operations ($0.7 million).

Net Revenues

Net revenues (revenues minus the cost of purchased power and other) were $541.2 million in 2006 compared to $546.5 million in 2005. The decrease was primarily due to decreased net revenues at TH Energy ($5.8 million) and LDC ($5.5 million) partially offset by increased net revenues at Telecom ($5.4 million).

At TH Energy, the decrease in net revenues was primarily due to lower contributions from the remaining activities of the electricity retail business which concluded on December 31, 2006 ($17.8 million), partially offset by increased revenue from street lighting and expressway lighting services provided to the City under the terms of a new service agreement entered into as part of the purchase of the street lighting and expressway lighting assets from the City on December 31, 2005 ($12.1 million).

At LDC, the decrease in net revenues for the year ended December 31, 2006 was mainly due to lower distribution revenue from decreased consumption (26,437 GWh compared to 27,282 GWh) attributable to weather and Conservation and Demand Management ("CDM") programs ($13.7 million), a decrease in distribution rates following the OEB's decision on LDC's 2006 rate application regarding interest payable to related parties ($11.8 million), and a reduction of recoverability for PILs related to the elimination of Large Corporation Tax ($1.7 million). LDC's decrease in net revenues was partially offset by higher revenue recognition from CDM programs in 2006 ($14.2 million) and changes in allowable cost recovery stemming from the OEB's decision on 2006 rate application ($7.5 million).

At Telecom, the increase in net revenues was primarily due to increased margin from the sale of data managed services.

Expenses

Operating expenses were $194.2 million in 2006 compared to $191.2 million in 2005. The increase in operating expenses was primarily due to higher deferral of pension and regulatory costs at LDC for 2005 prior to inclusion of these costs in distribution rates effective May 1, 2006 stemming from the OEB's decision into LDC's 2006 rate application ($6.4 million), increased operating spending on CDM programs ($3.9 million), partially offset by lower property taxes ($6.7 million) mainly from realized gains on appeals related to 2002 to 2006 assessments.

Depreciation and amortization expense was $137.3 million in 2006 compared to $131.6 million in 2005. The increase was primarily due to the depreciation of street lighting and expressway lighting assets purchased from the City by TH Energy at the end of 2005.

Net interest expense was $61.1 million in 2006 compared to $69.0 million in 2005. The decrease was primarily due to lower interest expense in respect of the City Promissory Note commencing May 1, 2006 ($4.5 million) (see "Corporate Developments – Amended and Restated City Note") and higher interest received on short-term investments.

Other

Included in Other are amounts primarily relating to gains on disposals of property, plant and equipment. Other was $0.1 million in 2006 compared to $5.0 million in 2005. The decrease was due to gains realized in 2005 on disposals of excess properties at LDC ($2.4 million) and dark fibre assets at Telecom ($2.6 million).

Provision for PILs

Provision for PILs was $58.4 million in 2006 compared to $68.8 million in 2005. The decrease in the provision for PILs was primarily due to higher earnings before taxes in 2005 and lower temporary differences in LDC resulting from deductions of capital cost allowance and depreciation on fixed assets in LDC.

Discontinued Operations

In November 2006, the Board of Directors of TH Energy approved a plan to sell the water heater business. The results of operations and financial position of this business segment have been segregated and are presented as discontinued operations.

Income from discontinued operations was $2.2 million in 2006 compared to $1.5 million in 2005. The increase was primarily due to lower depreciation costs from lower asset book value ($1.1 million), partially offset by higher operating expenses related to marketing efforts ($0.5 million).

On February 8, 2007, TH Energy sold its water heater business to Consumers' Waterheater Income Fund for cash consideration of $40.8 million subject to post closing adjustments and transaction costs. See notes 23 and 26 to the Consolidated Financial Statements.

Quarterly Results of Operations

The tables below present unaudited quarterly consolidated financial information of the Corporation for 2006 and 2005 and reflect discontinued operations relating to water heaters. See note 23 to the Consolidated Financial Statements.

2006 quarter ended, (in thousands of dollars)	December 31 $	September 30 $	June 30 $	March 31 $
Revenues	549,931	598,581	534,930	563,566
Costs	499,836	541,858	487,257	508,454
Income from continuing operations	22,054	28,197	17,721	22,247
Net income	22,783	28,894	18,161	22,559

2005 quarter ended, (in thousands of dollars)	December 31 $	September 30 $	June 30 $	March 31 $
Revenues	636,206	772,121	586,972	610,973
Costs	591,429	713,039	520,859	557,242
Income from continuing operations	22,153	18,842	29,380	20,542
Net income	22,501	19,354	29,754	20,836

Liquidity and Capital Resources

Sources of Liquidity and Capital Resources

The Corporation's primary sources of liquidity and capital resources are cash provided by operating activities, short-term bank financing, interest income and debt capital market borrowings.

The Corporation does not believe that equity contributions from the City, its sole shareholder, will constitute a source of capital. In addition, the Corporation is not aware of any plan or decision by the City to permit the Corporation to sell equity to the public or other investors.

Liquidity and Capital Resources Year Ended December 31, (in thousands of dollars)	2006 $	2005 $
Cash and cash equivalents, beginning of period	448,370	386,625
Net cash provided by operating activities	112,728	325,087
Net cash used in investing activities	(188,602)	(174,722)
Net cash used in financing activities	(45,547)	(89,947)
Net cash provided by discontinued operations (1)	575	1,327
Cash and cash equivalents, end of period	327,524	448,370

Note:

(1) Consists of discontinued operations for water heaters. See note 23 to the Consolidated Financial Statements.

Cash Provided by Operating Activities

Cash provided by operating activities was $112.7 million in 2006 compared to $325.1 million in 2005. The decrease was primarily due to an unfavourable variance in accounts payable and accrued liabilities at LDC due to the payment in 2006 of rebates received at the end of 2005 ($174.9 million) and increased payments for PILs in 2006 from revisions to projected tax liabilities ($45.5 million), an unfavourable variance in the aggregate of accounts receivable and unbilled revenue at TH Energy due to reduced electricity activities ($39.8 million) and an unfavourable variance in deferred revenue primarily due to increased CDM initiatives at LDC ($34.6 million).

These variances were partially offset by a favourable variance in the aggregate of accounts receivable and unbilled revenue at LDC due to timing differences in the collection of large commercial customers at the end of 2006 ($53.8 million) and a favourable variance in electricity mark-to-market assets and liabilities at TH Energy resulting from the expiration of the electricity retail portfolio ($25.1 million).

Revolving Credit Facility

The Corporation is a party to a revolving credit facility agreement dated May 5, 2005 pursuant to which the Corporation may borrow up to $500 million, of which up to $175 million is available in the form of letters of credit. As at December 31, 2006, no borrowings for working capital were outstanding and letters of credit in the amount of $81.6 million had been issued. See note 9 to the Consolidated Financial Statements.

Operating Liquidity and Capital Resource Requirements

The Corporation's primary liquidity and capital resource requirements are for capital expenditures to maintain and improve the electricity distribution system of LDC, cost of power expense, interest expense and prudential requirements and third party credit support.

Cash Used in Investing Activities

Cash used in investing activities was $188.6 million in 2006 compared to $174.7 million in 2005. The increase was primarily due to an increase in regulatory assets from smart meter activities and settlement of variance accounts in LDC ($24.8 million), an increase in the purchase of property, plant and equipment at LDC to improve electricity distribution assets ($35.4 million), at TH Energy to improve street lighting and expressway lighting assets ($4.3 million) and at Telecom for the reinforcement of the core network and the deployment of the new Wi-Fi network ($3.4 million). These variances were partially offset by the investment of $60 million made by TH Energy in 2005 for the purchase of the street lighting and expressway lighting assets from the City.

Capital Expenditures

The following table summarizes the Corporation's capital expenditures for the years indicated.

Year Ended December 31, (in thousands of dollars)	2006 $	2005 $
Capital Expenditures from Continuing Operations		
LDC		
Distribution system	131,389	113,333
Technology assets	21,880	10,119
Other [1]	14,416	8,808
	167,685	132,260
Other [2]	17,622	68,095
Total capital expenditures	185,307	200,355
Capital Expenditures from Discontinued Operations		
Water heaters	3,865	3,638

Notes:

(1) Consists of vehicles, other work-related equipment, furniture and office equipment.
(2) Includes capital expenditures relating to TH Energy and Telecom.

Cash Used in Financing Activities

Cash used in financing activities was $45.5 million in 2006 compared to $89.9 million in 2005. The decrease was primarily due to a decrease in dividends paid ($21.8 million) and the reclassification of a large portion of customer deposits to long-term assets in 2006 ($21.9 million).

Prudential Requirements and Third Party Credit Support

In order to mitigate the risk of payment default, wholesale market participants are required to provide credit support for their obligations to the IESO in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings. A market participant's prudential requirements are determined by the IESO based on the participant's "maximum net exposure", subject to permitted reductions resulting from, among other things, good payment history, credit rating or, in the case of distributors, prudential support collected from retailers or customers.

In addition to prudential requirements, counterparties under bilateral contracts for the purchase and sale of electricity contracts may require parental guarantees or other forms of credit support. Also, electricity distributors may require retailers to maintain security arrangements (including letters of credit, surety bonds, cash deposits or lock-box arrangements) under terms prescribed by the OEB to protect against credit risk.

The City has authorized the Corporation to provide financial assistance to its subsidiaries, and LDC to provide financial assistance to other subsidiaries of the Corporation, in the form of letters of credit and guarantees, for the purposes of enabling them to carry on their businesses up to an aggregate amount of $500 million.

As at December 31, 2006, the Corporation had issued $56.5 million of parental guarantees on behalf of TH Energy in support of prudential requirements and obligations under bilateral contracts for the purchase and sale of electricity. The Corporation has also issued a parental guarantee to the City as part of an agreement by the City to purchase electricity at a fixed price from TH Energy. The value of the parental guarantee to the City was nil at December 31, 2006. See note 16 to the Consolidated Financial Statements.

Dividends

The shareholder direction adopted by the City with respect to the Corporation provides that the board of directors of the Corporation will use its best efforts to ensure the Corporation meets certain financial performance standards, including those relating to credit rating and dividends. Subject to applicable law, the shareholder direction provides that the Corporation will pay dividends to the City each year equal to the greater of $25 million or 50% of the Corporation's net income for the year. The dividends are not cumulative and are payable as follows:

- $6 million on the last business day of each of the first three fiscal quarters during the year;
- $7 million on the last business day of the fiscal year; and
- the amount, if any, by which 50% of the Corporation's net income for the year exceeds $25 million, within ten calendar days after the board of directors of the Corporation approves the Corporation's Consolidated Financial Statements for the year.

The board of directors of the Corporation declared and paid dividends totalling $46.2 million in 2006 and $68.0 million in 2005.

On March 1, 2007, the board of directors of the Corporation declared dividends in the amount of $27.2 million. The dividends are comprised of a $21.2 million payment for 2006 net income, payable to the City on March 9, 2007, and a $6.0 million payment in connection with the first quarter of 2007, payable to the City on March 30, 2007.

Corporate Developments

Appointments

On November 29, 2006, Anthony Haines was appointed President of LDC.

On December 6, 2006, Gordon Perks was appointed as a Director of the Corporation and David Shiner and Bill Saundercook were reappointed as Directors of the Corporation, each for a term of office that shall end on December 31, 2008.

Changes in Business

TH Energy operated a water heater rental business until February 8, 2007, at which time the business was sold to The Consumers' Waterheater Income Fund. See notes 23 and 26 to the Consolidated Financial Statements.

In December 2002, TH Energy ceased electricity retailing activities in respect of new customers following the implementation of price protection under the *Electricity Pricing, Conservation and Supply Act*, 2002. Remaining contracts and portfolio obligations were managed to expiration on December 31, 2006. See note 15 to the Consolidated Financial Statements.

Medium-Term Note Program

On January 13, 2006, the Corporation filed a short form base shelf prospectus in connection with the establishment of a medium-term note program ("MTN Program"). Under the terms of the MTN Program, the Corporation may offer and issue, from time to time, unsecured debentures in one or more series in an aggregate principal amount of up to $1 billion during the twenty-five months following the date of the prospectus. The debentures issuable under the MTN Program have been assigned a rating of "A" with a stable trend by DBRS and a preliminary rating of "A-" by S&P. As at December 31, 2006, no debentures had been issued under the MTN Program.

Amended and Restated City Note

On September 5, 2006, the Corporation announced that it and the City had amended and restated the outstanding $980.2 million promissory note between the Corporation and the City (the "City Note") effective

May 1, 2006 by fixing the interest rate at 6.11% (the same interest rate payable on the Corporation's outstanding senior unsecured debentures) and establishing an agreed repayment schedule ($245.1 million on the last business day before each of December 31, 2007, December 31, 2009 and December 31, 2011 and on May 6, 2013). Interest is calculated and payable quarterly in arrears on the last business day of March, June, September and December of each year. A copy of the amended and restated City Note is available at www.sedar.com. See note 11 to the Consolidated Financial Statements.

Ministry of Finance Tax Audit

The Ministry of Finance is currently carrying out a tax audit of the Corporation and its subsidiaries. Certain filing positions for PILs taken by the Corporation and its subsidiaries may be challenged on the audit. This may result in a material increase in the Corporation's reported tax obligations upon reassessment. As the audit has not yet been completed, management is not able to determine the impact, if any, of the audit on the Consolidated Financial Statements or the Corporation's tax reserves. The Corporation adjusts its tax reserves when there is sufficient information available, or when an event occurs requiring a change to the reserves.

Distribution Rates

In March 2005, LDC received approval from the OEB to increase distribution rates to recover $39.8 million, representing the third and final adjustments necessary to achieve a market-based rate of return of 9.88%. The rate increase was effective as of April 1, 2005 and subjected the LDC to a financial commitment to invest $39.8 million in CDM activities by September 2007.

In April 2006, the OEB approved a decrease in distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $58.0 million. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980.2 million promissory note between LDC and the Corporation from 6.8% to 5% per annum.

On January 26, 2007, LDC filed an Annual Rate Adjustment Application for 2007 Rates as directed to by the OEB. In accordance with the OEB's Incentive Regulation Model, LDC has sought authorization to increase its distribution rates by 0.4% on May 1, 2007.

Smart Meters

On June 13, 2006, the Province issued draft regulations clarifying the technical details of advanced metering infrastructure and data management. In support of the Province's decision to install smart meters throughout Ontario by 2010, LDC launched its smart meter project in 2006. The project objective is to install 711,000 smart meters and the supporting infrastructure by the end of 2009. LDC had installed 193,000 meters at December 31, 2006 and will use the experience gained from this initiative as an opportunity to further develop and test the new tools, processes, and network infrastructure to support the mass deployment of these smart meters.

On May 1, 2006, LDC implemented new distribution rates which included charges for smart meters of $0.47 per month for each residential customer and $1.04 per month for all other customers. The charges are the first part of the funding for LDC's smart meter program. Consistent with the OEB's direction, LDC has deferred capital expenditures, operating expenditures, and revenues relating to smart meters in regulatory asset accounts. When LDC files its application to clear the 2006 smart meter balances, the $0.47 and $1.04 riders will be removed (and replaced by new rate riders, if approved by the OEB). See note 7 to the Consolidated Financial Statements.

OEB Proposals for Multi-Year Electricity Rate Setting Plan

On June 19 and July 25, 2006, the OEB began a generic licence amendment proceeding that was intended to effect changes to the allowable cost of capital and to effect a multi-year electricity distribution rate setting plan via incentive regulation mechanisms for distributors. LDC responded to both proposals in writing, and participated in technical conferences held in August and September. In December 2006, in the interests of implementing

distribution rate changes for 2007 in a timely manner, the OEB discontinued its examination into LDCs' allowable cost of capital and second-generation incentive regulation mechanism.

Consumers' Gas Decision

On April 22, 2004, in a decision in a class action commenced against The Consumers' Gas Company Limited (now Enbridge Gas Distribution Inc.), the Supreme Court of Canada ruled that The Consumers' Gas Company ("Consumers' Gas") was required to repay that portion of certain late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. Although the claim related to charges collected by Consumers' Gas after the enactment of section 347 of the Criminal Code in 1981, the Supreme Court limited recovery to charges collected after the action was initiated in 1994. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for a determination of the plaintiffs' damages. The parties reached a settlement of this class action. The Ontario Superior Court of Justice has approved this settlement. However, the representative plaintiff, Mr. Garland, is appealing the settlement approval order in an attempt to increase the fees to which he is entitled for having acted as representative plaintiff and to receive lawyer's fees in connection with such efforts. Mr. Garland's appeal is pending.

LDC is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below and in the Corporation's annual information form, in which the issues are analogous.

The first is an action commenced against a predecessor of LDC and other Ontario MEU's under the Class Proceedings Act, 1992 seeking $500.0 million in restitution for late payment charges collected by them from their customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is at a preliminary stage. Pleadings have closed but examinations for discovery have not been conducted and the classes have not been certified. After the release by the Supreme Court of Canada of its 2004 decision in the Consumers' Gas case, the plaintiffs in this proposed class action indicated their intentions to proceed with the litigation, but no formal steps have been taken.

The second is an action commenced against a predecessor of LDC under the *Class Proceedings Act, 1992* seeking $64.0 million in restitution for late payment charges collected by it from its customers that were in excess of the interest limit stipulated in section 347 of the Criminal Code. This action is also at a preliminary stage. Pleadings have closed and examinations for discovery have been conducted but, as in the first action, the classes have not been certified as the parties were awaiting the outcome of the Consumers' Gas class action.

The claims made against LDC and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by LDC in the first action would reduce the damages payable by LDC in the second action, and vice versa.

It is anticipated that the first action will now proceed for determination in light of the reasons of the Supreme Court in the Consumers' Gas class action.

LDC may have defences available to it in these actions that were not disposed of by the Supreme Court in the Consumers' Gas class action.

Also, the determination of whether the late payment charges collected by LDC from its customers were in excess of the interest limit stipulated in section 347 of the Criminal Code is fact specific in each circumstance. Accordingly, given the preliminary status of these actions, it is not possible at this time to reasonably quantify the effect, if any, of the Consumers' Gas decision on these actions or of these actions on the financial performance of the Corporation.

Share Capital

The authorized capital of the Corporation consists of an unlimited number of common shares of which 1,000 common shares are issued and outstanding as at the date hereof.

Services Provided to the City

Subsidiaries of the Corporation provide certain services to the City at commercial rates, including street lighting and maintenance services. In addition, the City and its agencies have entered into energy management contracts with TH Energy. See note 19 to the Consolidated Financial Statements.

Risks and Uncertainties

The financial performance of the Corporation is subject to a variety of risks and uncertainties including those described below:

Regulatory Uncertainty

The OEB regularly conducts consultations with interested stakeholders with respect to a number of areas which may affect electricity distributors.

The continuing restructuring of Ontario's electricity industry and other regulatory developments may affect the distribution rates charged by LDC and the costs LDC is permitted to recover. This may in turn have a material adverse effect on the financial performance of the Corporation. In particular, there can be no assurance that:

- the OEB may not set a lower recovery for LDC's cost of capital;
- the full cost of providing service to distribution customers will be permitted to be recovered through distribution rates;
- the OEB will not permit competitors to provide distribution services in a distributor's licensed area;
- the OEB will allow recovery for revenue lost as a consequence of the emergence and adoption of new technologies such as distributed generation, or unanticipated effects of conservation and demand management;
- parts of the LDC's services will not be separated from LDC and opened to competition; or
- regulatory or other changes will not be made to the PILs regime.

Changes to any of the laws, rules, regulations or policies applicable to the businesses carried on by the Corporation could have a significant impact on the Corporation. There can be no assurance that the Corporation will be able to comply with applicable future laws, rules, regulations and policies. Failure by the Corporation to comply with applicable laws, rules, regulations and policies may subject the Corporation to civil or regulatory proceedings which may have a material adverse effect on the Corporation.

Additional Debt Financing

The Corporation expects to borrow to repay the City Note when required to do so under the terms of the City Note. See note 11 to the Consolidated Financial Statements. The Corporation's ability to arrange sufficient and cost-effective debt financing to repay the City Note and for general corporate purposes (including credit support for prudential requirements) could be adversely affected by a number of factors, including the regulatory environment in Ontario, the Corporation's results of operations and financial condition, financial market conditions, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities, and general economic conditions.

Electricity Consumption

LDC's distribution rates typically comprise a fixed charge and a usage-based (consumption) charge. The volume of electricity consumed by LDC's customers during any period is governed by events largely outside LDC's control (principally sustained periods of hot or cold weather which increase the consumption of electricity, and sustained periods of moderate weather which decrease the consumption of electricity).

Credit Risk

LDC is subject to credit risk with respect to customer non-payment. LDC is permitted to mitigate the risk of customer non-payment using any means permitted by law, including security deposits (including letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB) under terms prescribed by the OEB), late payment penalties, pre-payment, pre-authorized payment, load limiters or disconnection.

In the event of an actual payment default and attendant bad debt expense incurred by LDC, roughly 80% of the expense would be related to commodity and transmission costs, and the remainder to LDC's distribution revenue. Accordingly, while LDC will be liable for the full amount of the default, there can be no assurance that the OEB will allow recovery of the bad debt expense from remaining customers. Rather, it is expected that the OEB will examine LDC's application for claiming bad debt expenses on a case-by-case basis. See note 15 to the Consolidated Financial Statements.

Condition of Distribution Assets

The Corporation's ability to continue to maintain and operate the distribution system reliably and safely in the future will depend on, among other things, the OEB allowing recovery of costs in respect of LDC's maintenance program and capital expenditure requirements for distribution plant refurbishment and replacement.

Refer to the Corporation's annual information form for more details on risks and uncertainties.

Disclosure and Internal Controls

The President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Corporation, together with management, have established and maintained disclosure controls and procedures of the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. These officers evaluated the effectiveness of the design and operation of disclosure controls and procedures as of December 31, 2006 and, based on that evaluation, have concluded that these controls are effective in providing such reasonable assurance.

The CEO and CFO, together with management, have also evaluated the design of internal controls over financial reporting of the Corporation as of December 31, 2006 in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. Based on that evaluation, these officers have concluded that the design of these controls is effective to provide such reasonable assurance.

During the quarter ending December 31, 2006, there were no changes to the Corporation's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, its internal control over financial reporting.

Significant Accounting Policies

The Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles, including accounting principles prescribed by the OEB, and are presented in Canadian dollars. In preparing the Consolidated Financial Statements, management of the Corporation makes estimates and assumptions which affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of the Consolidated Financial Statements and the reported amounts of revenues and expenses for the periods covered thereby. Actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance. The significant accounting policies of the Corporation are summarized in note 4 to the Consolidated Financial Statements.

Effective June 30, 2006, the Corporation adopted Emerging Issue Committee Abstract EIC-159 - "Conditional Asset Retirement Obligations" ["EIC-159"]. EIC-159 requires an entity to recognize a liability for the fair value of an asset retirement obligation ["ARO"] even though the timing or method of settlement is conditional on future events. The Corporation has identified conditional AROs and recognized a liability amounting to $1.6

million at year-end. The change has been accounted for prospectively as information is not available to allow it to be accounted for retrospectively. See note 4 to the Consolidated Financial Statements.

In April 2005, the Canadian Institute of Chartered Accountants released three Handbook Sections relating to financial instruments: 1530 – "Comprehensive Income", 3855 – "Financial Instruments – Recognition and Measurement" and 3865 – "Hedges" effective for annual and interim periods beginning on or after October 1, 2006. These new Sections establish standards for the recognition and measurement of financial instruments. The Corporation is currently evaluating the impact of these standards on its financial statements.

In December 2006, the Canadian Accounting Standards Board announced that as of March 31, 2008, they will be making a final decision on the date in which publicly accountable enterprises will be required to change over to International Financial Reporting Standards ("IFRS"). At this time, it is anticipated that by 2011 Canadian GAAP will be substantially the same as IFRS. Until the change over is finalized, companies will continue to describe their basis of reporting as Canadian GAAP.

Forward-Looking Information

Certain information included herein constitutes "forward-looking information". Forward-looking information means disclosure regarding possible events, conditions or results that is based on assumptions about future economic conditions and courses of action. In some cases, forward looking information can be identified by terminology such as "may", "will", "should", "expect", "anticipate", "believe", "estimate", "predict", "potential", "budget", "continue" or the negative of these terms or other comparable terminology. In addition, certain information included herein may contain forward-looking information attributable to third parties. Although the Corporation believes that it has a reasonable basis for the forward-looking information included herein, such information is subject to a number of risks and uncertainties that may cause actual events, conditions or results to differ materially from those contemplated by the forward-looking information. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, the ratings assigned to the Corporation and its debt securities by rating agencies, general economic conditions and weather. The Corporation does not undertake any obligation to update publicly or to revise any of the forward-looking information included herein after the date hereof, whether as a result of new information, future events or otherwise.

Additional Information

The information included herein reflects material events up to March 1, 2007, the date on which Consolidated Financial Statements of the Corporation were approved by the Corporation's board of directors.

Additional information with respect to the Corporation (including its annual information form and annual report) is available on the Canadian Securities Administrators' web-site at www.sedar.com.

Toronto, Canada

March 1, 2007

ANNEX C
REGULATION OF ONTARIO'S ELECTRICITY INDUSTRY AS IT RELATES TO TORONTO HYDRO

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REGULATION OF ONTARIO'S ELECTRICITY INDUSTRY AS IT RELATES TO TORONTO HYDRO

Capitalized and technical terms used but not defined in this Annex C are defined in "Glossary of Defined Terms".

1. Introduction

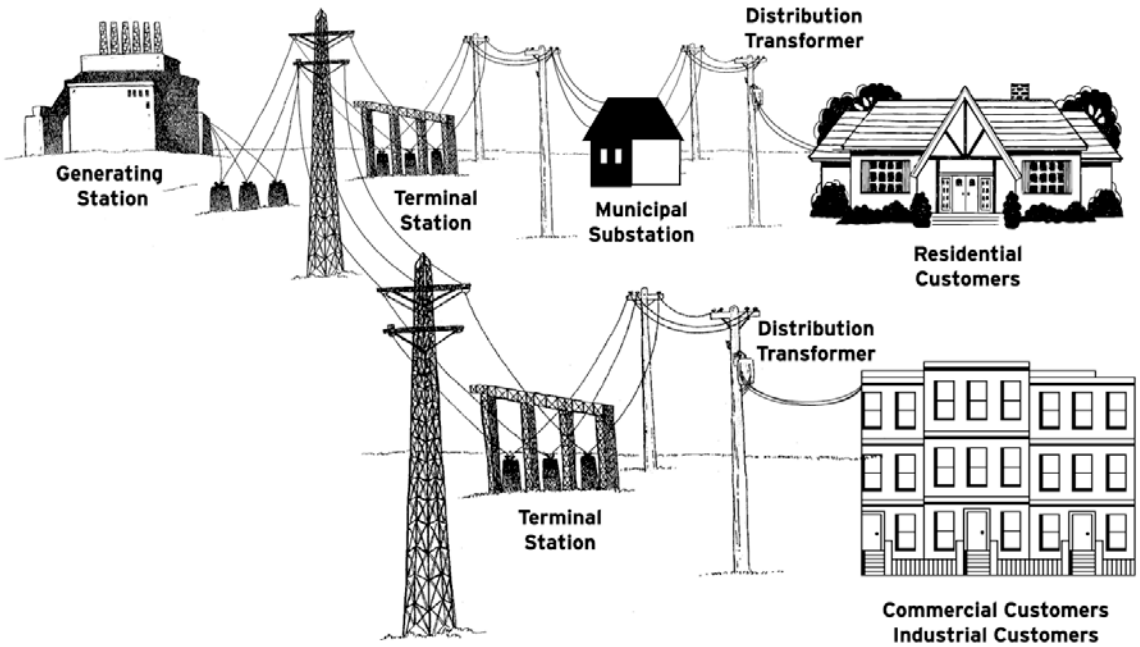
The electricity industry in Ontario is divided into four principal segments:

- generation - the production of electricity at generating stations using nuclear, fossil, hydro or other sources of energy;
- transmission - the transfer of electricity from generating stations to local areas using large, high-voltage power lines;
- distribution - the delivery of electricity to homes and businesses within local areas using relatively low-voltage power lines; and
- retailing - the purchase of electricity from generators and its sale to consumers together with a range of related services such as energy profiling and energy management.

Electricity produced at generating stations is boosted by nearby transformers to high voltages so that it can be moved long distances over transmission lines with limited power loss. The voltage is then reduced or stepped down at terminal stations for supply to distributors or large customers.

Distributors carry the electricity to distribution transformers that further reduce the voltage for supply to local customers. Electricity is distributed in Ontario through a network of local distributors that includes approximately 90 municipal distributors (the largest of which is LDC), a few privately owned distributors, and Hydro One Inc.

The following diagram illustrates the basic structure of an electricity infrastructure system.



2. Regulatory Developments

Before April 1999, the former Ontario Hydro generated most of the electricity sold in Ontario, owned substantially all of Ontario's transmission system and distributed and sold electrical power directly to municipal utilities, large industrial purchasers and rural commercial and retail customers. Ontario Hydro's central market operations division managed the integrated operation of Ontario's electricity system with responsibility for operations planning, security assessment, scheduling and co-ordination of the electricity system. Ontario Hydro also exercised the approval and inspection functions with respect to electrical equipment and electrical wiring installations throughout Ontario and approved the rates charged by municipal utilities.

In April 1999, the Province initiated a restructuring of Ontario's electricity industry, including the reorganization of Ontario Hydro. The purposes of the restructuring were generally to:

- disaggregate the industry into a regulated segment served by monopoly providers, including transmission, distribution, and market control functions, together with an unregulated competitive sector providing generation and energy retailing functions;
- promote competition in the unregulated sector as a means to achieve lower costs;
- bring effective regulation to the monopolistic functions under the auspices of the OEB;
- provide for the prudent repayment of the residual debt of the former Ontario Hydro; and
- foster a number of other objectives such as energy conservation and the overall financial viability of the industry.

Under the *Electricity Act, 1998*, Ontario Hydro was reorganized into five separate corporations (listed below under their current names):

- Ontario Power Generation (OPG), the entity responsible for the former Ontario Hydro's generation business;
- Hydro One Inc., the entity responsible for the former Ontario Hydro's electricity transmission, distribution and energy services businesses;
- Ontario Electricity Financial Corporation (OEFC), the entity responsible for managing and retiring Ontario Hydro's outstanding indebtedness and remaining liabilities;
- Independent Electricity System Operator (IESO), a non-profit corporation responsible for central market operations; and
- Electrical Safety Authority (ESA), a non-profit corporation responsible for the electric installation inspection function.

On May 1, 2002, the Province opened the wholesale and retail electricity markets to competition by providing generators, retailers and consumers with Open Access to Ontario's transmission and distribution network.

At the wholesale market level, this permitted generators, wholesalers, suppliers and marketers from both within and outside Ontario to compete to sell electricity to authorized Market Participants. At the retail market level, customers became free to enter into sales contracts with the licensed electricity supplier of their choice. Distributors were required to deliver electricity on behalf of retailers and other suppliers, and were required to supply electricity to any Standard Supply Customers who did not contract with other suppliers for their electricity commodity requirements.

Market Participants (including distributors and retailers) were and remain required to satisfy and maintain prudential requirements prescribed by the IESO, which include credit support with respect to outstanding market obligations in the form of letters of credit, cash deposits or guarantees from third parties with prescribed credit ratings. The prudential requirements are intended to mitigate the risk of payment default in a market where electricity is consumed at the moment it is generated but payment is not made until a later date.

Also under the *Electricity Act, 1998*, electricity utilities in Ontario were required to separate their distribution businesses from their other businesses. The resulting stand-alone distribution businesses were required to incorporate under the *Business Corporations Act (Ontario)* before November 7, 2000.

The business of LDC and other electricity distributors is regulated by the OEB which has broad powers relating to licensing and standards of conduct and service and the regulation of distribution rates charged by LDC and other electricity distributors.

The stand-alone distribution business came under the regulatory supervision of the OEB effective April 1, 1999. As a transitional measure intended to provide effective regulation for hundreds of distributor businesses, the OEB established distribution rates for each distributor based on actual 1999 costs for the "wires only" segments of the distributors' operations (i.e., functions deemed to be necessary for the conveyance of electricity, excluding contestable functions like water heater rentals). Initial distribution rates were to have included OEB-approved returns to capital based on deemed capital structures, varying by distributor size. However, in response to a direction from the Province, the OEB determined that this capital return, known as market-based Rate of Return, would be phased in over a three-year period in order to mitigate the rate impact on consumers.

The OEB also established a system of Performance Based Regulation, which was initially intended to provide a streamlined method of regulating distributors by means of formula-based annual rate adjustments, accounting principally for inflation and a mandated productivity offset, subsequent to the establishment of initial rates. The original term of the Performance Based Regulation plan was intended to be three years.

In addition to recovering their own costs through distribution rates, distributors began to bill customers on a new basis for other upstream supply-related costs such as commodity supply (where applicable), transmission, wholesale market operations, and the debt retirement charge, which is a provincial levy on electricity consumption that is used to reduce the residual debt of the former Ontario Hydro. Distributors incur the upstream supply costs on behalf of their customers and pass these costs through to customers without mark-up or discount by way of dedicated rates that are established and approved by the OEB. Previously, distributors had billed customers on a 'bundled' or aggregated basis under which upstream supply costs were not separately set out.

Immediately after Open Access, during the summer of 2002, Ontario experienced higher than expected electricity prices due to prolonged periods of unseasonably hot and humid weather and unanticipated shortages of Ontario-based generation capacity. The demand-weighted average wholesale price of electricity in Ontario from May 2002 to December 2002 was approximately 5.6¢ per kWh.

In November 2002, the Province announced its intention to implement a plan to lower electricity prices payable by certain customer classes. In December 2002, the Province passed the *Electricity Pricing, Conservation and Supply Act, 2002* which, among other things:

- fixed the price of electricity commodity payable by Low Volume Consumers and Designated Consumers at 4.3¢ per kWh (retroactive to May 1, 2002);
- capped distribution rates at then current levels and deferred further rate increases and certain cost recoveries by distributors;
- required distributors to obtain Ministerial approval to proceed to the OEB with an application for any change in rates;
- deemed certain costs and variance account balances of distributors to be "regulatory assets" (which were reflected in a distributor's balance sheet until the manner and timing of disposition was determined by the OEB);
- capped transmission rates at then current levels and deferred further rate increases and certain cost recoveries by transmitters;
- fixed wholesale market charges at 0.62¢ per kWh (effective December 1, 2002);
- required municipalities to confirm their original decision to commercialize their respective distribution companies; and

- introduced measures intended to encourage conservation and the establishment or expansion of electricity generating facilities in Ontario.

The price freeze and the rate caps were originally expected to continue until at least May 1, 2006. During the period that the price freeze was in effect, distributors and retailers were compensated, with respect to commodity costs, by the Ontario Electricity Financial Corporation:

- in the case of distributors, for amounts by which the price paid by distributors for electricity purchased by them in the then IEMO administered wholesale market on behalf of Low Volume Consumers and Designated Consumers was greater than the fixed price per kWh; and

- in the case of retailers, for amounts by which the retail contract price between retailers and Low Volume Consumers and Designated Consumers was greater than the fixed price per kWh.

In November 2003, the Province:

- announced its intention to increase the price of electricity payable by Low Volume Consumers and Designated Consumers from 4.3¢ to 4.7¢ per kWh on the first 750 kWh consumed during a month and 5.5¢ thereafter, effective April 1, 2004;

- directed the OEB to develop the RPP, a new pricing mechanism, to take effect no later than May 1, 2005 for setting the price of electricity payable by Low Volume Consumers and Designated Consumers;

- announced initiatives with respect to the third distribution rate adjustment necessary to fully implement the market-based Rate of Return, and the recovery of regulatory assets; and

- announced initiatives to broaden the scope of distribution activities that could be undertaken by utilities to include those related to the conduct of CDM programs and the facilitation of cleaner and renewable energy sources.

In December 2004, the Province enacted the *Electricity Restructuring Act, 2004*, which gave legislative effect to the initiatives described above, and also reshaped the industry in other respects.

The *Electricity Restructuring Act, 2004* established the OPA, as a non-profit, self-financed corporation with the mandate to ensure long-term electricity supply adequacy in Ontario. The OPA is not a Crown agency. As a consequence, it will not have access to the Province's credit, nor may the Province provide any guarantees. However, the Province may invest in the OPA by purchasing its securities. The OPA is authorized to enter into contracts for the supply as well as the conservation of electricity, and is responsible for developing an integrated power system supply plan in furtherance of its mandate. The OPA is entitled to recover the costs of its operations from electricity consumers under rates regulated by the OEB, and will carry variance accounts capturing any temporary differences between costs charged to the OPA by generators and amounts collected from consumers under the RPP.

The *Electricity Restructuring Act, 2004* also created a hybrid wholesale electricity market under which the output from generators owned and operated by OPG are to be provided at prices to be determined by the OEB. These prices and quantities will be combined with prices and quantities resulting from contracts with non-utility generators and with residual prices and quantities determined in the spot market to form a blended wholesale price for electricity.

The *Electricity Restructuring Act, 2004* placed responsibility for the determination of electricity prices for certain customers with the OEB in the form of an RPP, for application generally to Low-Volume Consumers and Designated Consumers. Precise eligibility for the RPP has been determined through regulations. The purpose of the RPP is to provide a stabilized electricity price to Low Volume Consumers and Designated Consumers that will, over time, result in Low Volume Consumers and Designated Consumers paying the true cost of the electricity they consume. At any point in time, any cumulative variance between amounts paid to generators for RPP supplies, and the corresponding amounts collected from customers, will be reflected in variance accounts held by the OPA. The OEB is required to have regard to both the forecast price of electricity over the applicable rate period, and any existing balances in the OPA variance accounts, such that the forecast balance in the variance accounts whenever the

OEB resets the RPP price would be zero at the end of the rate period. Customers that are not eligible for RPP, as well as those who opt out of the RPP, but who continue to purchase commodity on a standard supply basis, will pay a variable price determined by the consumption-weighted average hourly Ontario energy price applicable to each billing period.

Effective January 1, 2005 the IESO implemented, pursuant to the *Electricity Restructuring Act, 2004*, a new price adjustment applicable to LDC customers. This new price adjustment, referred to as the "Global Adjustment", is currently a monthly, varying rate calculated by the IESO based on the forecast difference between electricity market prices and the mix of regulated and contract prices paid to electricity generators. This calculation results in positive or negative bill adjustments to LDC customers depending on prevailing market conditions. At the wholesale level, LDC is billed by the IESO using daily variable rates in respect of the electricity consumed by its non-RPP customers. The difference between the amount received from the IESO by LDC and the amount credited to non-RPP customers is being tracked in a regulatory variance account. Disposition of this Global Adjustment variance account balance will be in accordance with the OEB's guidelines for reviewing variance and deferral accounts.

The *Electricity Restructuring Act, 2004* also introduced a new body, the Conservation Bureau, which is responsible for assuming a leadership role in planning and coordinating electricity conservation measures and load management in Ontario. That legislation also permitted distributors to provide services that would assist the Government of Ontario in achieving its goals in electricity conservation including services related to the promotion of electricity conservation and the efficient use of electricity; electricity load management; and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In order to promote conservation initiatives, distributors were required, as a condition of receiving the third distribution rate adjustment necessary to achieve a market-based Rate of Return, to make a one-time investment in CDM activities equal to one year of the additional revenue from the third MBRR distribution rate adjustment.

On February 23, 2005, the Minister of Energy announced the new pricing structure of electricity supplied by OPG. The new pricing structure, effective April 1, 2005 is based on an average price for electricity supplied by OPG's regulated assets, effective through to March 31, 2008 and a revenue cap on the majority of output from OPG's unregulated assets, effective as a transitional measure, through to April 30, 2006. On February 9, 2006 the Minister of Energy made a further announcement extending the revenue cap until March 31, 2008, on electricity supplied by OPG's unregulated assets.

The new pricing structure had an immediate impact on large industrial and commercial electricity customers who use more than 250,000 kWh per year. While residential, small business and certain other consumers will not be immediately affected by the new pricing structure, the OEB blended the various prices paid to generators into a new fixed price that consumers now pay under the RPP, which took effect April 1, 2005.

The OEB formulated two pricing plans for RPP-eligible customers, depending on how customers' electricity consumption is metered — that is, a pricing plan for customers without Smart Meters, and a pricing plan for customers with Smart Meters. Both plans came into effect on April 1, 2005.

For the majority of customers (i.e., those who are not yet equipped with Smart Meters) the existing two-tier structure was continued, with a new two-tier pricing of 5.0 cents/kWh for the first tier and 5.8 cents/kWh for the balance of consumption per month. From April 1, 2005 to October 31, 2005, the threshold was 750 kWh/month. From November 1, 2005, for non-residential RPP customers the threshold continued to be 750 kWh/month, but for residential customers, the first tier threshold began to vary seasonally. The threshold has been set at 1,000 kWh/month from November 1 to April 30 (winter), and 600 kWh/month from May 1 to October 31 (summer). Prices initially set by the OEB under RPP were to remain the same for at least one year and thereafter would be reviewed and adjusted, if necessary, every six months beginning May 2006.

For customers with Smart Meters, the RPP defines a TOU pricing structure with different price levels depending on the period during the day when electricity is used. The on-peak period refers to when demand for electricity is highest; the mid-peak period refers to when demand for electricity is moderate; and the off-peak period when demand for electricity is lowest. The hours that comprise the on-peak period, mid-peak, and the off-peak period are different in summer and winter. Currently, OEB-set prices for the off-peak, mid-peak, and on-peak periods are 3.4 cents/kWh, 7.1 cents/kWh, and 9.7 cents/kWh respectively.

In recognizing the challenges posed by TOU metering and billing, the OEB did not obligate distributors to offer this pricing plan, at this time. Therefore, in 2006, LDC did not offer a TOU-RPP pricing structure.

On January 26, 2005 the OEB issued to the Minister of Energy its Smart Meter Implementation Plan in response to the Minister's June, 2004 directive. On November 3, 2005 the *Energy Conservation Responsibility Act, 2005* (Bill 21) was introduced into the legislature. Bill 21 is intended to remove barriers to, and promote opportunities for, energy conservation. Bill 21 established the *Energy Conservation Leadership Act, 2005* and made certain amendments to the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* in support of this government initiative.

Amendments to the *Electricity Act, 1998* under Bill 21 include the establishment of a Smart Metering Entity whose responsibility will be to collect, manage and aggregate data related to the consumption or use of electricity. The amendments also set out requirements of distributors, retailers and other persons vis-à-vis the Smart Metering Entity. Specifically, distributors, retailers and other persons will be required to provide the Smart Metering Entity with the information it requires to fulfil its objects or conduct its business.

Amendments to the *Ontario Energy Board Act, 1998* under Bill 21 permit the Minister to issue directives to the OEB relating to the government's smart metering initiatives. Such directives may require the OEB to amend conditions in licences it issues, and may address the regulatory and accounting treatment of costs to ensure that distributors, transmitters, retailers or other persons are not financially disadvantaged by the implementation of the government's smart metering initiatives.

Bill 21 referred to the Standing Committee on Justice Policy for public hearings throughout February 2006 and the *Energy Conservation Responsibility Act, 2005* received Royal Assent on March 28, 2006.

3. Regulation of Distributors

3.1 Overview

The business of distributors is regulated by the OEB, which has broad powers with respect to:

- licensing;
- standards of conduct; and
- the regulation of distribution rates charged by distributors.

3.2 Distribution Licence

The OEB has granted LDC a distribution licence. The term of the licence expires on October 16, 2023. The licence allows LDC to own and operate an electricity distribution system in the City of Toronto, subject to the terms and conditions contained in the licence that are summarized below:

- *Term, Amendment* — The term of the current licence may be extended by the OEB. The licence may be amended by the OEB on the application of any person, or by the OEB unilaterally, if it considers the amendment to be necessary in order to implement a Ministerial directive or in the public interest having regard to the objectives of the OEB and the purposes of the *Electricity Act, 1998*.

- *Information Disclosure* — LDC is required to maintain records of and provide the OEB with such information as the OEB may require from time to time. LDC is also required to notify the OEB of any material change in circumstances that adversely affects or is likely to adversely affect its business, operations or assets as soon as practicable, but in any event, within 20 days of the date upon which any such change occurs.

- *Obligation to Maintain System Integrity* — LDC is obligated to maintain its distribution system to meet the standards established in the Distribution System Code (described below) and the market rules and any other recognized industry operating or planning standard adopted by the OEB.

- *Restrictions on Provision of Information* — LDC must not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. LDC must not disclose consumer information regarding a consumer, retailer, wholesaler or generator to a third party without the written consent of the consumer, retailer, wholesaler or generator except where such information is required to be disclosed to comply with any legislative or regulatory requirements, including the conditions of LDC's licence; for billing settlement or market operation purposes; for law enforcement purposes; or to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. Consumer, retailer, wholesaler or generator information may be made available on a non-discriminatory basis where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. LDC is required to inform consumers, retailers, wholesalers and generators of the circumstances under which consumer information may be released to a third party without their consent. LDC must ensure that third parties do not use this information for any other purpose except the purpose for which it was disclosed.

- *Obligation to comply with Codes* — LDC is obligated to comply with the applicable provisions of the Affiliate Relationships Code, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code (all described below) unless it obtains an exemption from the OEB.

- *Distribution Rates* — LDC may not impose charges for the distribution of electricity except in accordance with its distribution rate order.

- *Customer Rebates* — LDC is required to pass through any rebates received stemming from market rules and regulations.

- *Expansion of the Distribution System* — LDC may not construct, expand or reinforce its distribution system or make an interconnection except in accordance with the *Ontario Energy Board Act, 1998* and regulations, the Distribution System Code and applicable provisions of the Market Rules.

- *Consumer Complaint and Dispute Resolution* — LDC is required to establish proper administrative procedures for resolving complaints by consumers and other Market Participants and must refer unresolved complaints to an independent third-party complaint resolution agency approved by the OEB.

The licence contains additional terms and conditions which became effective upon commencement of Open Access:

- *Obligation to Provide Non-discriminatory Access* — LDC is required to provide generators, retailers and consumers with access to its distribution system and distribute electricity on behalf of such parties in accordance with the terms of its licence.

- *Obligation to Connect* — LDC must not refuse a request to connect to its distribution system that has been made in accordance with the terms of the Distribution System Code and LDC's rate order as approved by the OEB.

- *Obligation to Sell Electricity* — LDC must sell electricity to persons connected to its distribution system in accordance with the Standard Supply Service Code, the Retail Settlement Code and LDC's Rate Order as approved by the OEB.

- *Separation of Business Activities* – LDC must keep financial records associated with distributing electricity separate from its financial records associated with any other activities in accordance with the Accounting Procedures Handbook and as the OEB otherwise requires.

3.3 Industry Codes

The OEB has established the Affiliate Relationships Code, the Distribution System Code, the Retail Settlement Code and the Standard Supply Service Code. These codes prescribe minimum standards of conduct and standards of service for distributors in the competitive electricity market and have been assigned the following ranking in the event there is a conflict: Affiliate Relationships Code, Distribution System Code, Retail Settlement Code and Standard Supply Service Code. These codes are summarized below.

Affiliate Relationships Code

The Affiliate Relationships Code establishes the standards and conditions for the interaction between electricity distributors and their affiliated companies and is intended to minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities, protect the confidentiality of consumer information collected by a distributor and ensure that there is no preferential access to regulated services. In the Affiliate Relationships Code, an electricity distributor is referred to as a "utility". LDC is a utility that is subject to the Affiliate Relationships Code.

The Affiliate Relationships Code prescribes the following standards of conduct for a utility:

- *Degree of Separation* — A utility must ensure accounting and financial separation from all affiliates and must maintain separate financial records and books of account. A utility must be physically separated from any energy services affiliate involved in the supply of electricity and natural gas-related activities (including retailing of electricity, marketing of natural gas, generation of electricity, energy management services and appliance sales, services and rentals). A utility must ensure that at least one-third of its board of directors is independent from any affiliate (the OEB exempted LDC and other municipal utilities from this requirement until July 1, 2006).

- *Sharing of Services and Resources* — When a utility shares services or resources with an affiliate, it must do so in accordance with a services agreement which may be reviewed by the OEB. When a utility shares information services with an affiliate, all confidential information of the utility must be protected from access by the affiliate. There are also rules governing when a utility may share employees with an affiliate.

- *Transfer Pricing* — When a utility provides a service or product to an affiliate, the utility must provide the service or product for a price not less than the fair market value of the service or product or, where fair market value is not available, not less than a cost-based price which reflects the costs of producing the service or product, including a return on invested capital. Where a utility sells assets to an affiliate, it must be at a price not less than the net book value of those assets. Where a utility purchases a service, resource or product from an affiliate, the utility shall pay no more than the fair market value.

- *Financial Transactions with Affiliates* — A utility may provide loans to, guarantee the indebtedness of, or invest in the securities of an affiliate on terms no more favourable to the affiliate than market terms, provided that the amount of support or investment on an aggregated basis over all transactions with affiliates is not greater than 25% of the utility's total equity.

- *Equal Access to Services* — A utility may not provide preferential access to an energy services affiliate or endorse or support marketing activities of any such affiliate. A utility may not transfer a customer to an affiliate, without the customer's written consent. A utility is required to take all reasonable steps to ensure that an affiliate does not use the utility's name, logo or other distinguishing characteristics in a manner which would mislead consumers as to the distinction between the utility and the affiliate.

- *Confidentiality of Information* — Subject to limited exceptions (e.g., for billing or market operation purposes or if required by law), a utility is prohibited from releasing to an affiliate confidential information relating to a consumer, retailer or generator without the consent of that person.

Distribution System Code

The Distribution System Code establishes the minimum conditions that a distributor must meet in carrying out its obligations to distribute electricity under its licence and the *Energy Competition Act, 1998*, and has been amended as the regulatory environment has evolved.

The Distribution System Code prescribes the following standards for a distributor:

- *Connection Agreements and Conditions of Service* —A distributor must document its conditions of service that describe its operating practices and connection policies. A distributor's conditions of service must include, among other things, the types of connection service performed by the distributor for each customer class, and the conditions under which these connections will be performed (connection policy); the distributor's basic connection service that is recovered through its revenue requirements and does not require a variable connection charge; the distributor's capital contribution policy by customer class for an offer to connect, including procedures for collection of capital contributions; the demarcation point at which the distributor's operational responsibilities for distribution equipment end at the customer; the demarcation point at which the distributor's ownership of distribution equipment ends at the customer; the billing cycle period and payment requirements by customer class; design requirements for connection to the distribution system; voltages at which the distributor provides electricity and corresponding load thresholds; type of meters provided by the distributor; meters required by customer class; Quality of Service standards to which the distribution system is designed and operated; conditions under which supply may be unreliable or intermittent; conditions under which service may be interrupted; conditions under which the distributor may disconnect a consumer; policies for planned interruptions; the business process the distributor uses to disconnect and reconnect consumers, including means of notification and timing; the distributor's rights and obligations with respect to a customer; rights and obligations a consumer or embedded generator has with respect to the distributor; the distributor's liability limitations in accordance with the Distribution System Code; the distributor's dispute resolution procedure; terms and conditions under which the distributor provides other services in its capacity as a distributor. A distributor's conditions of service must also contain its security deposit policy; a detailed description of how the amount of security is calculated; limits on amount of security required; process and timing for returning the security. A distributor will be liable to a customer and a customer will be liable to a distributor only for damages which arise out of the wilful misconduct or negligence of the other in connection with the distribution services provided and will not be liable to the other if prevented from performing its obligations because of a force majeure event.

- *Connections and Customer Charges* — A distributor may refuse to connect a building or facility to its system if an electrical connection does not meet its design requirements. In determining whether to make a connection, the distributor may consider certain factors, including whether a particular connection would violate the terms of its licence or applicable laws, potentially have an adverse effect on the reliability or safety of the system or the quality of distribution services received by an existing connection, impose an unsafe worker situation beyond normal risks inherent in the operation of a distribution system, materially decrease the efficiency of the system or if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit. If a distributor refuses to connect a building or facility to its system, it must inform the customer of the reasons and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy, it is the customer's responsibility to resolve the issue. For residential customers, a distributor must define a basic connection cost (including supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment and up to 30 metres of overhead conductor or an equivalent credit for underground services) and recover the cost as part of its revenue requirement. For non-residential customers, a distributor may define a basic connection cost by rate class and recover the cost either as part of its revenue requirement or through a basic connection charge payable by the customer. All customer classes will be subject to a variable connection charge to be calculated as the cost associated with the installation of connection assets above and beyond the basic connection, which the distributor may recover through a connection charge or equivalent payment.

- *Expansions* — If a distributor must construct new facilities to its main distribution system or increase the capacity of existing system facilities in order to connect a specific customer or group of customers, the distributor must perform an initial economic evaluation of the project (in accordance with prescribed valuation methodology) to determine if the future revenue will pay for the capital cost and ongoing maintenance costs of the expansion project. If an expansion is required, a distributor must make a written offer to the customer containing, among other things, a description of the labour, material, equipment and overhead required to build the expansion, an estimate of the amount that will be charged to the customer to complete the expansion, whether the offer includes competitive work for which the customer may obtain an alternative bid and a description of the process if applicable and whether the offer is firm or an estimate. In case the offer is an estimate the distributor must perform a final economic evaluation and either obtain from the customer, or credit the customer for, any difference between the initial and final calculated amounts. The amount a distributor may offer to charge a customer (other than a generator or distributor) to construct the expansion to the distributor's system may not exceed the customer's share of the difference between the present value of the projected capital costs and ongoing maintenance costs for the equipment and the present value of the projected revenues for such distribution services. If there is a shortfall between the present value of the projected costs and revenues, a distributor may propose to collect all or part of the difference from the customer through a capital contribution made in accordance with the distributor's documented policy on capital contributions by customer class. Such customers will be entitled to receive rebates from the distributor on capital contributions in circumstances where unforecasted customers connect to the distribution system during the customer connection horizon.

- *Alternative Bids* — A customer may pursue an alternative bid with a pre-qualified contractor if an expansion project requires a capital contribution from the customer and the construction work does not involve work with existing circuits. The customer is responsible for the contractor's cost, the work performed by the contractor and administering the contract with the contractor. The distributor may charge a customer that chooses an alternative bid any costs incurred by the distributor associated with the expansion project, including costs for additional design, engineering or installation of facilities required to complete the project that were in addition to the original connection offer and costs for inspection or approval of the work performed by the contractor. In case the customer has elected to pursue an alternative bid for the competitive work, the distributor must perform a final economic evaluation and include a transfer price for the expansion work performed by a qualified contractor hired by the customer. The distributor obtains from the customer, or credits the customer for, any difference between the initial and final calculations.

- *Enhancements* — A distributor is required to continue to plan and build the distribution system for reasonable forecast load growth. A distributor may perform enhancements to the system for purposes of improving system operating characteristics or relieving system capacity constraints. Historical average enhancement costs per kilowatt are included in the economic evaluation in proportion to the incremental demand requested by the customer

- Expansion Deposits — For expansions that require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the present value of the forecasted revenues. For residential developments, the distributor returns the percentage of the expansion deposit in proportion to the actual connections once the facilities are energized. For commercial and industrial developments the distributor returns the expansion deposit in proportion to the actual demand that materialized in each of the five years following energization.

  Where the customer chooses the alternative bid option, a distributor may retain up to 10% of the expansion deposit for up to two years from the energization of the facilities and use this part of expansion deposit to cover the distributor's costs for repair, or bringing up the facilities built by the qualified contractor to standard.

- *Operations* — A distributor is required to operate and maintain its distribution system in accordance with good utility practice and performance standards to ensure reliability and quality of electrical service on a short-term and long-term basis, follow good utility practice in managing

the power quality of the distribution system, maintain a voltage variance standard in accordance with standards prescribed by the Canadian Standards Association, respond to and take reasonable steps to investigate all consumer power quality complaints and report to the consumer on the results of such investigation, and take corrective actions or direct a consumer to take corrective actions where there is a condition that adversely affects the distribution system. A distributor is required to develop and maintain appropriate emergency plans in accordance with prescribed requirements and establish management policies that include arrangements for on-call personnel in accordance with good utility practice, the establishment and operation of a call centre to provide customers with available information in the event of an outage and the identification of distribution circuits for emergency services. A distributor is required to abide by safety rules that apply to routine utility work and be a member of an industry specific, recognized health and safety organization in Ontario. A distributor is required to implement an industry recognized health and safety program that includes training and regularly conducted audits. A distributor is required to have a corporate policy addressing environmental stewardship that applies to all of its operations.

- *Disconnection* — Under the *Electricity Act, 1998*, a distributor may shut off the distribution of electricity to a property if any amount payable by a customer is overdue provided that reasonable notice of the proposed shut off is provided to the customer. A distributor is required to establish physical and business processes for disconnection and reconnection.

- *Security Deposits* — A distributor may require a security deposit from a customer that the distributor bills unless the customer has a prescribed good payment history (e.g., not received more than one disconnection notice during the prescribed period or no more than one payment to the distributor within the prescribed period has been returned for insufficient funds or a disconnect/collect trip has not occurred) for a prescribed period (e.g., one year in the case of residential customers, five years in the case of non-residential customers in a <50 kW class and seven years in the case of other non-residential customers). A distributor must not require a security deposit if the customer provides a letter from another electricity or gas distributor in Canada confirming a good payment history for the prescribed period where part of the good payment history has occurred in the previous 24 months or a customer (other than a customer in a >5,000 kW class) provides a satisfactory credit check made at the customer's expense. The maximum amount of a security deposit which a distributor may require is limited to the product of the billing cycle factor (i.e., 2.5 if the customer is billed monthly, 1.75 if the customer is billed bi-monthly and 1.5 if the customer is billed quarterly) and the estimated bill based on the customer's average monthly load with the distributor during the most recent 12 consecutive months within the past two years. The amount of a security deposit is subject to reduction if the customer has a prescribed credit rating from a recognized rating agency. The form of security deposit shall be cash or cheque (in the case of residential customers) cash, cheque at the customer's discretion or letter of credit (in the case of non-residential customers), at the customer's discretion, or such other form as is acceptable to the distributor. Interest accrued on security deposits is required to be paid out at least once every 12 months or on return or application of the security deposit or closure of the account whichever comes first. A distributor is required to review every customer's security deposit at least once in a calendar year to determine whether the deposit is required to be returned to the customer (e.g., on the basis that the customer is now in compliance with the prescribed good payment history). A customer is also permitted to make a demand for a review under certain circumstances. A distributor is required to return to a third party any amount of security deposit paid directly to the distributor by a third party on behalf of a customer, including interest, where applicable.

- *Metering* — A distributor must, subject to certain exceptions, provide, install and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distribution system. Metering data collected by a distributor for settlement and billing purposes is subject to a validating, estimating and editing process.

- *Distributor's Responsibilities to Customers, Generators and Other Distributors* — A distributor is required to make reasonable efforts to respond promptly to a customer's request for connection and, in any event, within 15 calendar days after receipt of a customer's written request and is required to make every effort to connect the customer to the system within 60 calendar days after

receipt of a customer's written request. A distributor has an implied contract with any customer that is connected to its distribution system and receives distribution services from it, the terms of which are embedded in the distributor's conditions of service, the Rate Handbook, the distributor's rate schedules, the distributor's licence and the Distribution System Code. A distributor is required to make available a generation connection information package (containing, among other things, information with respect to the process for having a generation facility connected to a distribution system and the standard connection terms). A distributor is also required to respond promptly and within prescribed time periods to requests for connection from a generator or other distributor. A distributor is required to observe specific timelines relating to the connection to its distribution system of both micro-generation facilities and other generation facilities and must ensure that the safety, reliability and efficiency of the distribution system is not materially or adversely affected by the connection of a generation facility to the system. A distributor may not build part of its system in another distributor's licensed service area except where the part of the distribution system that is to be located inside the other licensed service area is dedicated to the delivery of electricity to the distributor, there is no apparent opportunity for both distributors to share the distribution facilities and the distributor in whose service area the distribution facilities are to be located determines that the presence of the distribution facilities in that location does not impinge on its distribution operations.

- *Embedded Generators* — Generators embedded within distribution systems will be indirectly connected to the grid controlled and operated by the IESO through lines and facilities owned by distribution companies. The Distribution System Code contains a suggested process for connecting embedded generators to the distribution system to ensure safe and reliable operation of the distribution system.

- *Net Metering* — Net metering is a regulatory construct that allows customers generating electricity for their own use from eligible renewable sources (water, wind, solar power and agricultural biomass) to reduce their net energy costs by exporting surplus generated energy back onto the distributor's distribution system for credit against future energy the customer consumes from the distributor's distribution system. Net metering specifies an annual accounting cycle during which unused credits can be carried over from one bill to the next. Effective February 10, 2006, distributors are required to make net metering available to eligible customers in their licensed service area who use equipment that has a maximum cumulative output of 500kW.

- *Provision of Information* — A distributor is required to communicate general market and educational information to its customers as required by the OEB.

Retail Settlement Code

The Retail Settlement Code outlines the obligations of a distributor with respect to its relationship with retail Market Participants and its role as a retail market settlements administrator.

Under the terms of the Retail Settlement Code, a distributor is required to:

- unbundle the costs of competitive electricity services (i.e., cost of electricity based on prices determined in the wholesale market administered by the IESO) and non-competitive electricity services (i.e., administrative charges, transmission services and other costs) required to support the wholesale market; and

- record in variance accounts the difference between amounts billed by the IESO to the distributor for competitive and non-competitive electricity services and the aggregate amounts billed by the distributor to consumers, retailers and others for the same services.

A distributor is also required to provide electricity billing and settlement services to retailers and customers which include:

- preparing electricity bills which unbundle, among other things, competitive and non-competitive electricity services and distribution charges; and

- providing billing options.

A distributor is currently required to provide two billing options to retailers and customers – retailer-consolidated billing and distributor-consolidated billing.

Under retailer-consolidated billing, the distributor bills the retailer for all competitive and non-competitive electricity services and its distribution charges and the retailer is responsible for customer billing. The retailer is responsible for customer non-payment risk under retailer-consolidated billing. If a retailer is not paid by a customer, the retailer may direct that the customer be returned to Standard Supply Service (the retailer is responsible to the distributor for all costs that the customer incurs prior to completion of the transfer back to Standard Supply Service. The retailer is entitled to OEB approved charges from LDCs for its services under retailer-consolidated billing).

Under distributor-consolidated billing, the distributor bills the customer for all non-competitive (calculated by the distributor) and competitive (calculated either by the retailer or the distributor based, in either case, on the contract terms between the customer and the retailer, or if the customer is price protected under the RPP) electricity services and its distribution charges. Differences between the cost of competitive services incurred by the distributor on behalf of customers served by the retailer and the amount payable under the terms of the contract between the customer and the retailer are billed or credited to the retailer and settlement statements are issued. The distributor is responsible for customer non-payment risk under distributor-consolidated billing. The distributor is entitled to OEB approved charges from retailers for its services under distributor-consolidated billing.

Distributors may require retailers to maintain security arrangements, including letters of credit, surety bonds, cash deposits or lock-box arrangements, under terms prescribed by the OEB, to protect against the risk of payment default by retailers. In addition, distributors may mitigate the risk of customer non-payment using any means allowed by law, including security deposits (under terms prescribed by the OEB), late payment penalties, prepayment, pre-authorized payment, load limiters or disconnection.

The Retail Settlement Code also provides for:

- *Service Transaction Requests* — A distributor is required to accept and process requests by customers to change to alternative services provided by competitive retailers and requests from retailers to return consumers to standard service supply in certain circumstances (including non-payment). The Retail Settlement Code sets out the rules and procedures for service transaction requests.

- *Maintenance of Customer Records and Access to Information* — A distributor is required to maintain records for all customers for which it determines settlement costs. A distributor is also required to make available to a consumer, or a competitive retailer designated by a consumer, validated meter usage information, historical customer specific information (including information on electricity use, regulated rates, meter characteristics and payment information) and, if requested by a retailer, information (including hourly price data) used to calculate competitive electricity costs over a billing period.

- *Service Agreements* — A distributor is required to enter into a service agreement with any licensed retailer that wishes to provide electricity services to consumers connected to its system and utilize the retail settlement services offered by the distributor. The terms of the service agreement between a distributor and licensed retailers are prescribed by the OEB and include procedures for billing and payment, security arrangements to protect against the risk of payment default by retailers, treatment of confidential information and dispute resolution.

- *Special Provisions for RPP Consumers* – The RPP that came into effect on April 1, 2005 for eligible consumers replaced the electricity commodity pricing regime in effect since April 1, 2004. The Retail Settlement Code along with the Standard Supply Service Code codify the rules by which licensed electricity distributors are required to implement the RPP.

Standard Supply Service Code

The Standard Supply Service Code provides that a distributor will provide Standard Supply Service to persons connected to the distributor's distribution system:

- who do not advise the distributor in writing that they do not wish to purchase electricity from the distributor;
- who request the distributor in writing to sell electricity to them; or
- whose retailer is unable to sell electricity to them.

Under the Standard Supply Service Code, a distributor's rates for Standard Supply Service will be approved by the OEB and will consist of the price of electricity and an administrative charge which will allow the distributor to cover its costs of providing the service.

Among other things, the *Electricity Pricing, Conservation and Supply Act, 2002* fixed the price of electricity payable by Low Volume Consumers and Designated Consumers at 4.3¢ per kWh and authorized the payment of a provincially funded rebate to these customers equal to the difference between the price paid by them for electricity since the commencement of Open Access and the fixed price of 4.3¢ per kWh.

Because LDC had been charging its small volume/residential customers for the electricity supplied to them at 4.3¢ per kWh, these customers were not entitled to receive a rebate. At November 30, 2002, LDC's small volume/residential Standard Supply Customers had an aggregate net negative balance of $51.5 million in their purchase power variance accounts. In December 2002, LDC received a one-time reduction in its power bill from the IESO in settlement of this amount.

During the period that the price freeze was in effect, LDC was entitled to receive from, or was required to pay to, the Ontario Electricity Financial Corporation the amount by which the price paid by LDC for electricity purchased by it in the IESO administered wholesale market on behalf of its Low Volume Consumers and Designated Consumers is greater than, or is less than, the fixed price.

A distributor may mitigate the risk of non-payment from Standard Supply Service customers by using any means permitted by law, including security deposits (under terms prescribed by the OEB), late payment penalties, prepayment, pre-authorized payment, load limiters or disconnection.

The Standard Supply Service Code has been revised to codify the rules for the RPP that is intended to provide stable and predictable electricity pricing, encourage conservation and ensure the price consumers pay for electricity better reflects the price paid to generators. RPP prices came into effect April 1, 2005 and were determined by the OEB based on a blend of fluctuating, fixed and capped prices paid to generators. At that time RPP prices were set at 5.0 ¢ per kWh for the first 750 kWh used in any month (increasing to the first 1,000 kWh per month starting in November 2005 for residential consumers) and 5.8 ¢ per kWh for consumption above this level. Starting in the spring of 2006, and every six months after that, RPP prices will be adjusted by the OEB, as required, in order to true up the RPP prices with the prices paid to generators. Any difference will be blended into prices set by the OEB for the next period. On May 1, 2006, the RPP rates were set at 5.8 cents per kWh for the first 750 kWh (600 kWh per month for residential customers) and 6.7 cents for consumption above this level. On November 1, 2006, the RPP rates were set at 5.5 cents per kWh for the first 750 KWh (1,000 kWh per month for residential) and 6.4 cents per kWh for consumption above this level.

3.4 Distribution Rates

On May 11, 2005, the OEB issued the 2006 Rate Handbook, which replaced the Rate Handbook previously used by Distributors. The 2006 Rate Handbook was composed of filing requirements and guidelines and set out how the OEB generally intended to address applications for 2006 electricity distribution rates.

The 2006 Rate Handbook has been replaced by a plan established by the OEB to provide for the re-basing and annual adjustment of distributor rates, including those of LDC. For 2007, all distributors will have their base distribution rates (i.e., ongoing rates exclusive of temporary rate riders) adjusted formulaically to reflect an allowance for inflation offset by a negative adjustment for deemed productivity growth. In each of three subsequent years, approximately one third of electricity distributors will have their distribution rates reviewed in detail and reset through a cost of service-type of rate proceeding. In 2008 and 2009, distributors that have not yet gone through the rebasing process will have annual rate adjustments made on a basis similar to that for 2007. In 2009 and 2010, those distributors that have already had rates rebased will be subject to a ‘third generation’ incentive rate adjustment

mechanism for the purpose of determining further annual rate adjustments. The third generation incentive mechanism has not yet been defined but may include inter-distributor cost comparisons and cost benchmarking.

Also included in the OEB rate plan is a migration of all utilities to a 60:40 debt:equity deemed capital structure for ratemaking purposes. Distributors moving to a higher equity ratio (including LDC) will transition over a period of two years commencing in 2008, while those moving to a lower equity structure will transition over a variable number of years depending on the size of the adjustment relative to their current structure.

Market-Based Rate of Return

Before the introduction of rate caps in December 2002, the OEB had authorized electricity distributors to adjust their distribution rates to incorporate a MBRR. The MBRR comprised a cost of debt based on an allowed debt rate applied to the amount of debt capitalization, together with an allowed rate return on equity applied to the amount of equity capitalization. The MBRR adjustment was being phased in over three adjustment periods (2001, 2002 and 2003) to lessen the rate impact on customers. Effective on each of December 1, 2000 and March 1, 2002, the OEB authorized LDC to increase its distribution rates to allow for the recovery of additional annual revenue of $39.8 million.

On January 17, 2005, LDC filed a rate application requesting OEB authorization with respect to an increase in distribution rates to allow for the recovery of $39.8 million, representing the third and final adjustment necessary to achieve a MBRR. As mandated by the OEB in December 2004, the rate increase subjected LDC to a financial commitment to invest $39.8 million in CDM activities by September 2007.

Performance Based Regulation

Performance Based Regulation is generally used as a regulatory mechanism to simulate the incentives and penalties of competition in different circumstances, including natural monopolies where actual competition is not possible or undesirable for other reasons. In general, Performance Based Regulation operates to limit rates or cap prices while at the same time providing for minimum standards of customer service (and system reliability in the case of electricity utilities) which discourage attempts to increase margins by reducing service levels. Performance Based Regulation is typically implemented in two steps – the first consisting of the establishment of initial rates and the second consisting of adjustments of those rates by means of a formula that provides for an inflation adjustment that is offset by a prescribed level of productivity improvement and a further mechanism that provides for an adjustment on account of costs or other amounts that are deemed to be recoverable but are outside the application of the formula. In inflation-adjusted terms, the application of the formula results in a rate reduction equal to the productivity factor but provides an opportunity to increase the margin by maintaining costs below the inflation adjustment and by productivity improvements in excess of the productivity factor.

The Rate Handbook sets out a first generation Performance Based Regulation framework for the annual adjustment of distribution rates in 2002 and 2003 by a percentage amount based on a formula reflecting the combined effect of:

- annual changes in input costs, as determined by the OEB using a weighted index measuring changes in capital, labour and materials costs over the past year; less
- an annual deemed productivity improvement factor of 1.5% plus (or minus) "Z-factor" adjustments (described below).

A distributor whose input costs rose less than the percentage amount set by the OEB would increase its earnings relative to the prescribed formula. Similarly, a distributor whose productivity exceeded the specified minimum benchmark would increase its earnings relative to the prescribed formula.

The first annual distribution rate adjustments under Performance Based Regulation were completed on March 1, 2002.

The *Electricity Pricing, Conservation and Supply Act, 2002* established a rate cap period during which, among other things, the annual distribution rate adjustments under Performance Based Regulation were suspended. Since then, LDC's existing rates have been adjusted according to the processes described in this document.

In order to ensure that service quality does not decline, the OEB has prescribed service quality and reliability targets for distributors.

Other Regulated Charges

The 2006 Rate Handbook provides standard rates and guidelines to distributors with respect to other regulated charges that are non-competitive in nature and are regulated by the OEB, required under OEB codes and guidelines, governed by the market rules or are under the direction of the Province, including transmission charges and retail service charges relating to services provided by distributors to retailers in accordance with the Retail Settlement Code.

Regulatory Assets

Under the *Electricity Pricing, Conservation and Supply Act, 2002*, regulatory assets representing certain costs incurred by distributors were created. Prior to that, distributors:

- were permitted to record for future recovery transition costs incurred as a result of preparing for Open Access;
- were required to track and accumulate for future recovery variance amounts incurred during the period of January 1, 2001 to April 30, 2002 between the cost of electricity purchased from OPG and the revenue distributors were permitted to receive for electricity supplied by them to consumers;
- were required to track and accumulate for future settlement variances between amounts charged by distributors to consumers and corresponding non-competitive electricity service costs (e.g., IESO fees and uplift charges for ancillary services and imported electricity and transmission charges) incurred by distributors in the wholesale market administered by the IESO; and
- were permitted to record for future recovery costs with respect to certain extraordinary events that met the criteria established in the Rate Handbook and that were approved by the OEB.

The OEB was in the process of determining the manner and timing of disposition of certain of these amounts prior to the introduction of rate caps. Under the *Electricity Pricing, Conservation and Supply Act, 2002*, these amounts were deemed to be "regulatory assets" to be reflected in a distributor's balance sheet until the manner and timing of disposition was determined by the OEB.

Pending the outcome of a final prudence review, and commencing March 1, 2004, the OEB authorized LDC to recover its regulatory assets, comprised of transition costs and the retail settlement variance account, over a four-year period.

Upon completion of its prudence review, the OEB granted final approval for recovery of LDC’s regulatory asset account balances on July 26, 2005. Key elements of the decision included:

- recovery of all of LDC's transition costs related to market opening;
- recovery of all RSVA account balances as at December 31, 2003.
- a direction for LDC to calculate interest charges on the balances for certain accounts such as pre-market opening energy variance (the OEB previously did not allow carrying charges for these accounts); and
- a direction for LDC to calculate interest for each account from January 1, 2004 to March 31, 2005, based on the revised balance at December 31, 2005, and to include this interest amount in the 2005 rate adjustment.

As part of the 2006 Rate Application, LDC applied and received approval for the recovery of all remaining RSVA account balance as at December 21, 2004, as well as the deferred OEB fees and pension costs.

PILs

OEB regulatory practice provides for the recovery of forecast PILs liabilities through distribution rates. LDC is generally at risk for variances between forecast and actual PILs paid, excluding variances arising from changes in tax rates not assumed in the setting of rates for the period in question, which are disposed of through deferral accounts.

3.5 LDC Rate Applications

On June 28, 2000, the OEB approved, on an interim basis, the rates proposed by LDC in its initial rate application dated April 14, 2000. These rates were effective from July 1, 2000 and reflected the initial unbundling of the distribution component from the cost of power component and did not include an adjustment to incorporate a market-based Rate of Return.

On October 17, 2000, LDC filed an amended rate application in response to the OEB's decision to phase in market-based rate increases (see "Market-Based Rates of Return" above). In the application, LDC elected a 9.88% target return on equity and requested a rate adjustment to allow for recovery of additional annual revenue of $39.8 million (representing approximately one-third of the incremental revenue necessary to achieve the return on equity elected by LDC in its application). For typical residential customers using 1,000 kWh per month, the proposed rate increase represented a 3.2% increase. The amended rate application was approved by the OEB effective December 1, 2000.

On May 2, 2001, LDC filed an application requesting OEB authorization to pass through an approved increase in the cost of electricity supplied by OPG The application was approved by the OEB effective June 1, 2001.

On January 25, 2002, LDC filed a rate application requesting OEB authorization with respect to the following rate adjustments:

- a decrease in distribution rates for the period March 1, 2002 to February 28, 2003 representing a revenue reduction of approximately $3.6 million (1.1%) under Performance Based Regulation (the difference between the 0.4% increase in input costs for the year ended December 31, 2001 calculated by the OEB and the OEB prescribed productivity factor of 1.5%);

- an increase in distribution rates to allow for the recovery of additional annual revenue of $39.8 million (representing the second rate adjustment necessary to achieve the 9.88% target return on equity requested by LDC in its initial rate application);

- an increase in distribution rates to allow for the recovery of additional annual revenue of approximately $6.6 million (representing the revenue lost as a result of LDC's decision to change its methodology relating to the penalties charged on overdue customer accounts); and

- permitted recoveries relating to PILs for the period October 1 to December 31, 2001 and for 2002 on an annualized basis (approximately $60 million).

The application was approved by the OEB effective March 1, 2002.

On January 23, 2004, LDC filed a rate application requesting OEB authorization with respect to an increase in distribution rates to allow for the recovery of additional annual revenue of $21.6 million (representing approximately 25% of LDC's regulatory assets as at December 31, 2002). The application was approved by the OEB effective April 1, 2004.

The permitted recovery relating to PILs for 2002 (approximately $58.6 million in the case of LDC) was used by the OEB for purposes of permitted recoveries relating to PILs for 2004.

2005 Rate Application

The OEB issued filing guidelines on December 20, 2004 for 2005 distribution rate adjustments, directing distributors to file rate applications no later than January 17, 2005, for rates effective April 1, 2005 to April 30, 2006. For LDC, the rate change was comprised of:

- the third instalment of the MBRR to achieve the full market-based Rate of Return. The rate increase was conditional on a financial commitment by LDC to reinvest the same amount in CDM activities. On December 10, 2004, the OEB granted approval of LDC's proposed CDM plan. The amount of this adjustment was $39.8 million and was in effect from March 1, 2005 to April 30, 2006. Since the actual implementation date was April 1, 2005, the rate was "grossed up" by a factor 14/13 to ensure the full collection of this 14-month adjustment over 13 months;

- the allowance or "gross-up" for LDC's PILs liability for 2005; and

- the second instalment of regulatory asset recovery.

The OEB granted final approval for recovery of LDC's regulatory asset account balances on July 26, 2005.

2006 Rate Application

In 2004, the OEB undertook a Rate of Return/Cost of Service Regulation review for the purpose of establishing 2006 rates for distributors. A Rate of Return/Cost of Service Regulation approach involves a detailed assessment of a distributor's cost levels in all applicable functional areas in order to establish the overall cost of service to be recovered from consumers through revised distribution rates. To facilitate the processing of approximately 90 distributor rate applications, the OEB issued the 2006 Rate Handbook on May 11, 2005.

On April 12, 2006, the OEB approved a decrease in distribution rates of LDC for the period May 1, 2006 to April 30, 2007 representing a revenue reduction of approximately $58.0 million. The methodology used by the OEB to establish the distribution rates was based on, among other things, a rate base of $1.861 billion, a deemed debt to equity structure of 65:35 and an allowed return on equity of 9%. The OEB also allowed for the recovery of regulatory assets related to prior years' pension costs and OEB fees and reduced the allowable interest rate recoverable on related party debt including the outstanding $980.2 million promissory note between LDC and the Corporation from 6.8% to 5% per annum.

2007 Rate Application

On December 20, 2006, the OEB issued a 2007 rate adjustment model and corresponding instructions to distributors for the purpose of adjusting distribution rates effective May 1, 2007. Base distribution rates (exclusive of rate riders for the recovery of regulatory assets and other items) will be adjusted based on a formula to reflect an allowance for inflation and a productivity offset, as well as the removal of an allowance for Large Corporations Tax, with a net effect of approximately 0.4%. See note 3 to the Consolidated Financial Statements.

LDC filed its application for 2007 rates (to be effective May 1, 2007) on January 26, 2007, in accordance with the instructions issued by the OEB for the 2007 annual rate adjustment. See note 26 to the Consolidated Financial Statements.

3.6 OEB Consultations

The OEB consults with interested stakeholders with respect to a number of areas which may affect electricity distributors.

Service Quality Regulation

Under Performance Based Regulation, the OEB prescribed service quality and reliability targets for electricity distributors. Prior to the introduction of the price freeze and rate caps under the *Electricity Pricing, Conservation and Supply Act, 2002*, the OEB had announced its intention to undertake a review and assessment of service quality standards and consult with stakeholders as part of a review of Performance Based Regulation. The OEB suspended

its review and consultation temporarily due to rate setting and other priorities, but has indicated in its Business Plan that it will resume these activities in 2007.

Time Of Use or Smart Meter Consultations

Smart Meters are designed to provide customers with timely consumption information that, when combined with variable time-of use pricing plans offered by distributors, will allow consumers to better manage their demand for electricity and ultimately result in more efficient use of Ontario's existing supply of electricity.

The Province has established targets for the installation of 800,000 Smart Meters by December 31, 2007 and installation of Smart Meters for all Ontario customers by December 31, 2010. The OEB consulted with stakeholders to identify options and address issues with regard to these targets. On January 26, 2005, the OEB submitted its proposed implementation plan that identified:

- the mandatory technical requirements for Smart Meters and the support systems distributors will require;
- regulatory mechanisms for the recovery of costs; and
- how barriers to implementation might be overcome; and

The report also addressed competitiveness in the provision and support of Smart Meters and the need for and effectiveness of non-commodity time of use rates.

The proposed phased-in installation plan will take several years and will initially focus on large consumers and residential and commercial consumers in large urban areas. Distributors will be responsible for owning, installing, operating and maintaining Smart Meters as they are rolled out across the Province. LDCs will also continue to be responsible for the customer interface, including billing and access to Smart Meter information data (with third parties), and will be held harmless from the stranding of existing meter assets. On an interim basis and in connection with rate adjustments for 2006, the OEB established smart meter rate riders to assist distributors with the financing of their smart meter installation costs. Deferral accounts to record these revenues as well as the associated revenue requirement costs of Smart Meter installations were also established.

Following issue by the OEB on January 26, 2005 to the Minister of Energy of its Smart Meter Implementation Plan, on November 3, 2005 the *Energy Conservation Responsibility Act, 2005* (Bill 21) was introduced into the legislature. Bill 21 is intended to remove barriers to, and promote opportunities for, energy conservation. Bill 21 will establish the *Energy Conservation Leadership Act, 2005* and will make certain amendments to the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* in support of this government initiative.

Amendments to the *Electricity Act, 1998* under Bill 21 include the establishment of a Smart Metering Entity whose responsibility will be to collect, manage and aggregate data related to the consumption or use of electricity. The amendments also set out requirements of distributors, retailers and other persons vis-à-vis the Smart Metering Entity. Specifically, Distributors, retailers and other persons will be required to provide the Smart Metering Entity with the information it requires to fulfil its objects or conduct its business.

Bill 21 was referred to the Standing Committee on Justice Policy for public hearings throughout February 2006 and received royal assent on March 28, 2006.

On July 26, 2006, the province announced that the IESO will act as the Smart Metering Entity.

Amendments to the *Ontario Energy Board Act, 1998* under Bill 21 permit the Minister to issue directives to the OEB relating to the government’s smart metering initiatives. Such directives may require the OEB to amend conditions in licences it issues, and may address the regulatory and accounting treatment of costs to ensure that distributors, transmitters retailers or other persons are not financially disadvantaged by the implementation of the government’s smart metering initiatives.

Cost Allocation Consultations

On March 9, 2005 the OEB announced that it will conduct a review of cost allocation in the electricity distribution sector based primarily on existing rate classifications and a limited number of rate design issues. In June, 2005, the OEB further announced that the cost allocation review will require Distributors to file updated cost allocation information that will be used by the OEB to consider the need for adjustments in the current share of distribution costs paid by the various classes of ratepayer on a utility-specific basis for 2007 rates. A Technical Advisory Team provided preliminary technical input and Technical Workshops provided for broader stakeholder discussions on:

- OEB cost allocation principles and methodologies;
- Priority rate design and rate classification matters; and
- Mandatory OEB filing requirements, OEB model design and data inputs.

Following the release of the OEB's mandatory cost allocation review filing requirements and cost allocation filing model, LDC filed cost allocation studies in January 2007

Cost of Capital and Incentive Regulation

Beginning in April of 2006, the OEB undertook a review of the cost of capital for electricity distributors concurrently with the development of an incentive regulatory mechanism for the purpose of determining rates for 2007. The OEB's consultations on these matters involved distributors and other stakeholders such as customer groups, and addressed issues including:

- whether the OEB had jurisdiction to establish cost of capital parameters and incentive mechanisms through the promulgation of codes;
- whether and if so by what methodology cost of capital parameters such as return on equity, debt rates, and capital structure should be updated; and
- what incentive mechanism should be adopted for the purpose of adjusted current rates for the 2007 rate year and beyond.

The OEB issued its Report in this matter on December 20, 2006. Its principal findings were that distributors' deemed capital structures would be harmonized over a transition period to a 60:40 debt:equity ratio; that the existing methodology for determining debt rates and rates of return on equity would be substantially continued, and that the OEB would not pursue the avenue of implementing these findings by way of codes at this time, but rather would do so by way of guidelines.

4. Regulation of Retailers

Electricity retailers may:

- sell or offer to sell electricity to consumers;
- act as agent or broker with respect to the sale of electricity; or
- act or offer to act as the agent or broker for a consumer with respect to the sale of electricity.

The key regulatory instruments authorized by the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* which regulate the electricity retailing and gas marketing activities of TH Energy are described below.

4.1 Electricity Retailer Licence

On March 7, 2000, the OEB issued an electricity retailer licence to TH Energy. This licence was renewed on March 7, 2005. The licence allows TH Energy to retail electricity subject to the terms and conditions contained in the licence which are summarized below.

- *Term, Amendments, Suspension or Revocation* — The licence is effective as of March 7, 2005 and terminates on March 6, 2010, although the term may be unilaterally extended by the OEB. The licence may be amended by the OEB on the application of any person, or by the OEB unilaterally, if it considers the amendment to be necessary in order to implement a Ministerial directive or in the public interest having regard to the objectives of the OEB and the purposes of the *Electricity Act, 1998*. The licence may be suspended or revoked if the OEB considers TH Energy to be in contravention of any applicable legislation or its licence or if TH Energy has been negligent or made fraudulent representations in carrying on its retail business.

- *Information Disclosure* — TH Energy is required to provide the OEB with information regarding its business and any other information the OEB may require in order to monitor compliance with the conditions of the licence, industry codes or any other legislative or regulatory requirements. TH Energy is also required to notify the OEB of any change in its officers or directors and any material change in the information provided to the OEB as part of the licence application process.

- *Obligation to comply with Codes* — TH Energy is obligated to comply with the applicable provisions of the market rules, the Electricity Retailer Code of Conduct (described below) and the Retail Settlement Code unless it obtains an exemption from the OEB.

- *Consumer Complaint and Dispute Resolution* — TH Energy is required to participate in the consumer complaints resolution process selected by the OEB.

4.2 Gas Marketer Licence

On March 7, 2000, the OEB issued a natural gas marketer licence to TH Energy. This licence was renewed on March 7, 2005, and extends to March 6, 2010. The licence allows TH Energy to carry on business as a gas marketer subject to the terms and conditions contained in the licence. TH Energy does not currently engage in any gas marketing activities.

4.3 Wholesaler Licence

On March 16, 2001, the OEB issued an electricity wholesaler licence to TH Energy. This licence was renewed on January 19, 2006. The licence allows TH Energy to purchase electricity from the markets administered by the IESO or directly from an electricity generator and to sell electricity through the markets administered by the IESO or directly to third parties other than consumers subject to the terms and conditions contained in the licence which are summarized below.

- *Term, Amendments, Suspension or Revocation* — The original licence was effective as of March 16, 2001 and, following its renewal on January 19, 2006, now terminates on January 18, 2011. The licence may be amended by the OEB on the application of any person, or by the OEB unilaterally, if it considers the amendment to be necessary in order to implement a Ministerial directive or in the public interest having regard to the objectives of the OEB and the purposes of the *Electricity Act, 1998*. The licence may be suspended or revoked if the OEB considers TH Energy to be in contravention of any applicable legislation or its licence or if TH Energy has been negligent or made fraudulent representations in carrying on its wholesale business.

- *Information Disclosure* — TH Energy is required to provide the OEB with information regarding its business and any other information the OEB may require in order to monitor compliance with the conditions of the licence, industry codes or any other legislative or regulatory requirements. TH Energy is also required to notify the OEB of any change in its officers or directors and any material change in the information provided to the OEB as part of the licence application process.

- *Obligation to comply with Market Rules* — TH Energy is obligated to comply with the applicable provisions of the market rules.

4.4 Electricity Generation Licence

On December 18, 2002, the OEB issued an electricity generation licence to TH Energy. The electricity generation licence was actually issued to TH Energy and TREC Windpower Co-operative (No.1) Incorporated (the co-venturers), in connection with a wind turbine located at Exhibition Place in the City of Toronto. The licence allows the co-venturers to generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person subject to the terms and conditions contained in the licence which are summarized below.

- *Term, Amendments* – The licence was effective as of December 18, 2002 and terminates on December 17, 2022, although the term may be extended by the OEB. The licence may be amended by the OEB on the application of any person, if it considers the amendment to be necessary in order to implement a directive issued under the *Ontario Energy Board Act, 1998* or in the public interest having regard to the objectives of the OEB and the purposes of the *Electricity Act, 1998*.

- *Information Disclosure* –The co-venturers are required to provide the OEB with information regarding any material change in circumstances that adversely affects or is likely to adversely affect its ability to comply with the conditions of the licence, as soon as practicable, but in any event within fifteen days of the date upon which the change occurs.

- *Obligation to Comply with Market Rules* – The co-venturers are obligated to comply with all applicable market rules under the *Electricity Act, 1998*.

4.5 Electricity Retailer Code of Conduct

The Electricity Retailer Code of Conduct:

- prohibits certain sales practices, including exerting undue pressure on or misleading consumers;

- prescribes the content of offering documents and contracts between retailers and residential and small business customers; and

- requires retailers to provide timely, accurate and verifiable comparisons and ensure that all descriptions and promises made in promotional material are accurate.

The Electricity Retailer Code of Conduct also provides that a retailer may not request a distributor to allow the retailer to supply electricity to a consumer without the consumer's written consent. Retailers are also required to keep customer information confidential subject to certain limited exceptions, including for billing or market operation purposes and compliance with applicable law or legal process.

4.6 Energy Consumers' Bill of Rights

The *Ontario Energy Board Act, 1998* was amended on July 1, 2002 to, among other things, strengthen consumer rights with respect to unfair practices by electricity and natural gas retailers. The amendments strengthened consumer rights by, among other things, enhancing consumers' cancellation rights after signing a contract with a retailer, requiring consumers to reaffirm any contract renewal and providing the OEB with increased enforcement powers.

The *Electricity Pricing, Conservation and Supply Act, 2002* established additional notice and disclosure requirements for retailers carrying on business after December 2002.

In August 2003, the *Ontario Energy Board Act, 1998* was amended to introduce certain changes to the mechanics relating to reaffirmation of retail contracts.

ACCOUNTING METHODOLOGY CHANGES

On January 1, 2007, THESL began recording an allowance for funds used during construction ("AFUDC"). This change in methodology was adopted to reflect the increase capital requirements related to the projected increase in capital investment. The methodology used by THESL follows the direction included in the Accounting Procedures Handbook for Electrical Distribution Utilities and was applied prospectively.

There are no other changes in accounting methodologies affecting the opening balances reported and test years included in this filing.

UNIFORM SYSTEM OF ACCOUNTS AND ACCOUNTING ORDERS

THESL is in compliance with the OEB's Uniform System of Accounts for electricity distributors and, where applicable, with the OEB's related accounting letters and orders.

Service Quality Measures
(Year End 2001 to 2006)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
1	**Measure (Customer Service Performance Indicators)**	**Description**	**Standard**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
2	New Service Connections								
3	<750 Volts	% connected within 5 days	90%	96.9%	96.7%	98.7%	98.4%	96.9%	97.0%
4	>750 Volts	% connected within 10 days	90%	98.8%	100.0%	98.6%	100.0%	98.6%	99.0%
5									
6	Underground Cable Locates	% located within 5 days	90%	97.6%	94.2%	90.9%	93.5%	95.9%	97.0%
7									
8	Telephone Accessibility	% answered within 30 seconds	65%	81.2%	70.0%	69.9%	85.6%	81.0%	81.4%
9									
10	Appointments	% kept as scheduled	90%	96.8%	96.6%	95.2%	98.7%	98.8%	99.0%
11									
12	Written Inquiry Response	% responded to within 10 days	80%	99.4%	87.5%	93.3%	97.1%	94.4%	89.0%
13									
14	Emergency Response	% responded to within 1 hour	80%	81.8%	**74.9%**	86.4%	89.3%	81.7%	85.0%
15									
16									
17	Call Centre Call Quality	Average % of all calls monitored	80%	N/A	N/A	N/A	85.0%	87.6%	87.0%

ELECTRIC INFRASTRUCTURE RELIABILITY PERFORMANCE INDICATORS

FIVE-YEAR HISTORICAL RELIABILITY PERFORMANCE

General

THESL tracks reliability performance indicators SAIDI, SAIFI and CAIDI in three ways:

1) Including all events
2) Without Major Event Days ("MEDs")
3) Without MEDs and Loss of Supply

An MED is defined by standard P1366/D12 of the Institute of Electrical and Electronics Engineers ("IEEE") as "events that are beyond the design and/or operational limits of a utility". The removal of MEDs allows a utility to "normalize" its reliability data to make trending and goal setting possible. An example of a "normalizing" application was the OEB allowed modification of 2003 reliability data in light of the August 14, 2003 provincial blackout.

Since amalgamation in 1998, THESL has experienced the following MEDs:

1) August 14 - 15, 2003 – 2 days, due to the blackout
2) September 19, 2003 – 8.01 minutes, due to Hurricane Isabel
3) July 26, 2005 – 6.93 minutes, due to the loss of supply to Esplanade TS
4) August 19, 2005 – 19.16 minutes due to major storm
5) August 20, 2005 – 6.44 minutes due to major storm
6) July 17, 2006 12.46 minutes, due to major storm
7) August 21, 2006 – 7.30 minutes, due to loss of supply to Scarborough TS

Five-Year Historical Reliability Performance

Tables 1, 2 and 3 show THESL's five-year historical reliability performance. Table 3, Reliability Performance without MEDs and Loss of Supply, most closely reflects the performance of the distribution supply system. The data indicate that SAIDI has remained fairly constant during this period.

Table 1: Reliability Performance
(including all events, except 2003 Provincial black-out)

Service Reliability Indicators Performance Measures (all events)	2002	2003**	2004	2005	2006
	Actual	Actual	Actual	Actual	Actual
SAIDI (# of hours of interruption per customer)	1.35	1.46	1.10	1.75	1.57
SAIFI (# of interruptions per customer)	1.59	1.98	1.59	2.01	2.17
CAIDI (# of hours per interruption)	0.85	0.74	0.69	0.87	0.72

(**) Excluding August 14-15, 2003 - 49.81 hours due to the blackout

Table 2: Reliability Performance without MEDs

Service Reliability Indicators Performance Measures (without MEDs)	2002	2003	2004	2005	2006
	Actual	Actual	Actual	Actual	Actual
SAIDI (# of hours of interruption per customer)	1.35	1.33	1.10	1.17	1.24
SAIFI (# of interruptions per customer)	1.59	1.90	1.59	1.81	2.06
CAIDI (# of hours per interruption)	0.85	0.70	0.69	0.65	0.60

Table 3: Reliability Performance without MEDs and Loss of Supply

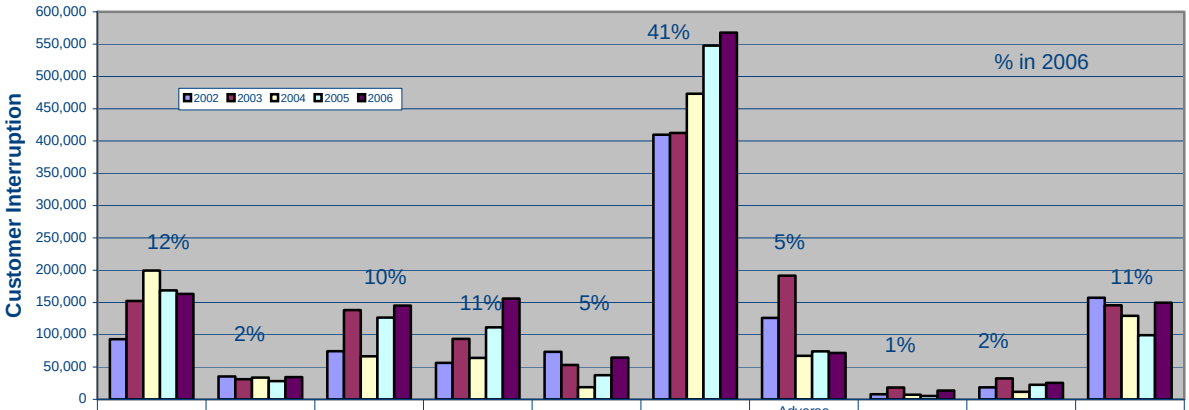
Service Reliability Indicators Performance Measures (without MEDs & Loss of Supply)	2002	2003	2004	2005	2006
	Actual	Actual	Actual	Actual	Actual
SAIDI (# of hours of interruption per customer)	1.23	1.22	1.00	1.17	1.17
SAIFI (# of interruptions per customer)	1.42	1.70	1.50	1.63	1.84
CAIDI (# of hours per interruption)	0.86	0.72	0.66	0.72	0.64

Cause Code Analysis

THESL tracks causes of service interruptions by the 10 Primary Cause Codes as specified in Table 15.2 of the Electricity Distribution Rate Handbook. Charts 1 and 2 show Customer Interruption ("CI") and Customer-Hours Interruption ("CHI") performance, for 2002-2006.

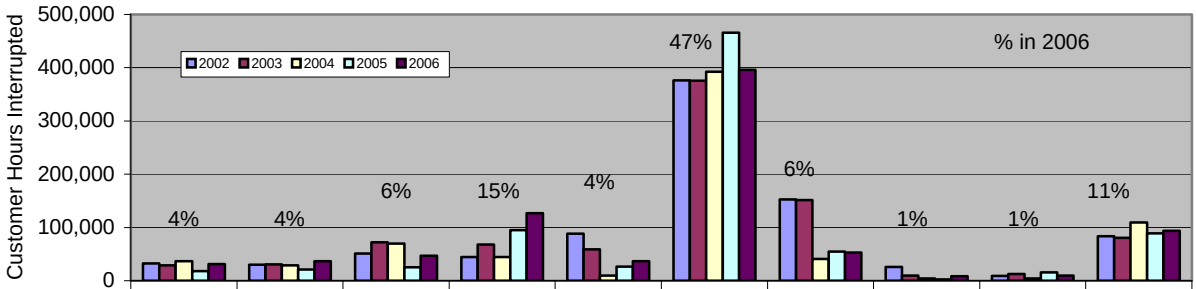
Defective Equipment was consistently the main cause of service interruption (41 percent in CI and 47 percent in CHI in 2006). The other top causes in 2006 for CI were Unknown (12 percent), Tree Contacts (11 percent), Foreign Interference (11 percent) and Loss of Supply (10 percent).

Chart 1 -Customer Interruption (CI) Summary by Cause (MED excluded)



	Unknown	Sched. Outage	Loss Of Supply	Tree Contacts	Lightning	Def. Equip.	Adverse Weather	Adverse Enviro	Human Element	Foreign Interf.
2002	93,080	35,416	74,511	56,362	73,529	409,800	126,021	7,874	18,515	157,265
2003	152,257	31,318	138,168	93,669	53,191	412,467	191,499	18,211	32,356	145,582
2004	199,505	33,760	66,709	64,074	18,875	473,247	67,437	7,079	11,600	129,244
2005	168,648	28,255	126,547	111,545	37,413	547,836	74,406	5,258	22,480	99,279
2006	163,253	34,413	145,193	156,035	64,550	567,673	71,855	13,657	25,528	149,614

Chart 2 - Customer-Hours Interruption (CHI) Summary by Cause
(MED excluded)



	Unknown	Sched. Outage	Loss Of Supply	Tree Contacts	Lightning	Def. Equip.	Adverse Weather	Adverse Enviro	Human Element	Foreign Interf.
2002	32,383	29,927	51,315	44,198	88,062	376,197	152,765	25,558	9,090	83,638
2003	29,030	30,790	72,398	67,942	58,835	375,840	151,491	9,501	12,649	80,593
2004	36,865	28,977	69,776	44,464	9,542	392,245	40,832	3,935	4,028	109,304
2005	17,979	21,216	25,347	94,999	26,192	465,871	54,853	2,555	15,404	88,820
2006	31,249	36,938	46,647	127,027	36,881	395,885	52,659	8,469	9,404	93,504

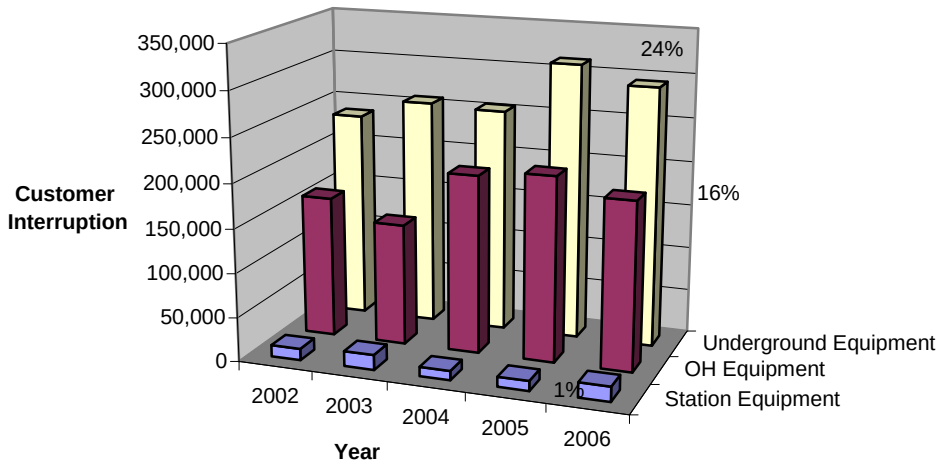
Defective Equipment Analysis

THESL tracks detailed causes of service interruptions by internal Secondary and Sub-secondary Cause Codes. For example: Primary Cause Code for Defective Equipment is

further categorized by the system types: “Overhead Equipment”, “Underground Equipment” and “Station Equipment”.

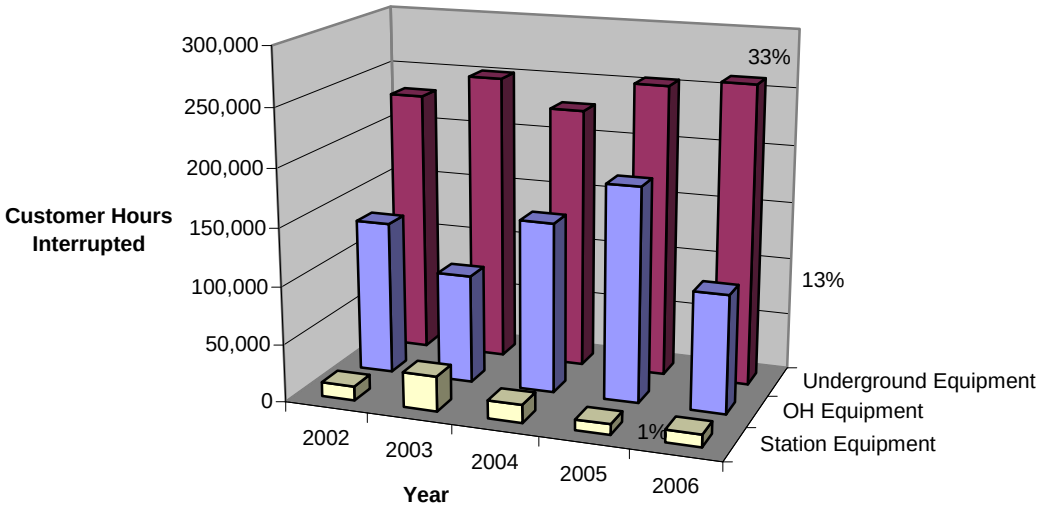
Charts 3 and 4 show the CI and CHI performance for 2002-2006 by system type. The distribution equipment reliability contribution in 2006 for CI was 24 percent – underground equipment, 16 percent – overhead equipment and 1 percent – station equipment (total 41 percent).

Chart 3 - Defective Equipment CI Performance (MED excluded)



	2002	2003	2004	2005	2006
Station Equipment	13,069	17,059	10,490	11,286	16,902
OH Equipment	160,332	137,664	201,923	209,133	190,468
Underground Equipment	236,242	257,689	254,710	313,067	293,808

Chart 4 - Defective Equipment CHI Performance (MED excluded)



	2002	2003	2004	2005	2006
Station Equipment	12,190	30,307	15,575	9,122	10,707
OH Equipment	133,395	94,345	147,876	185,704	102,189
Underground Equipment	230,585	251,160	227,972	254,557	260,865

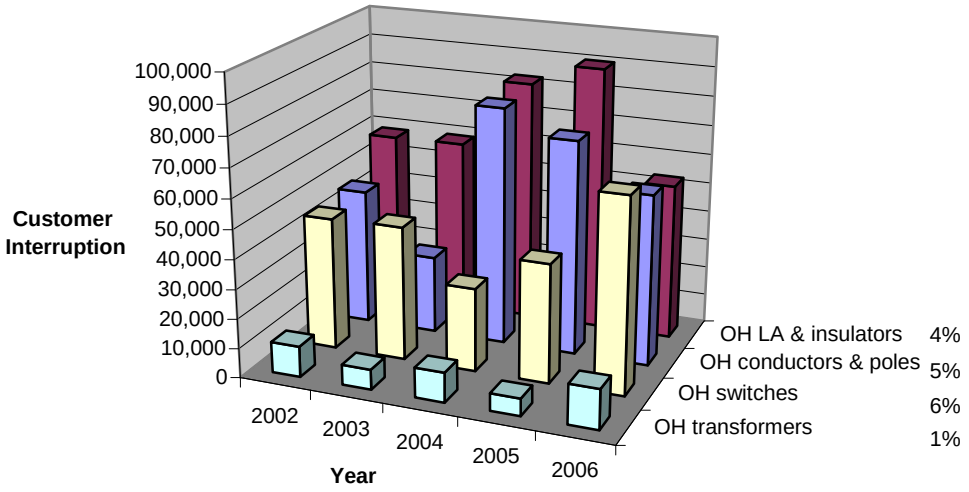
Overhead and Underground Equipment Reliability Analysis

Charts 5 and 6 show the CI and CHI performance of the Overhead Equipment for 2002-2006.

Charts 7 and 8 show the CI and CHI performance of the Underground Equipment for 2002-2006.

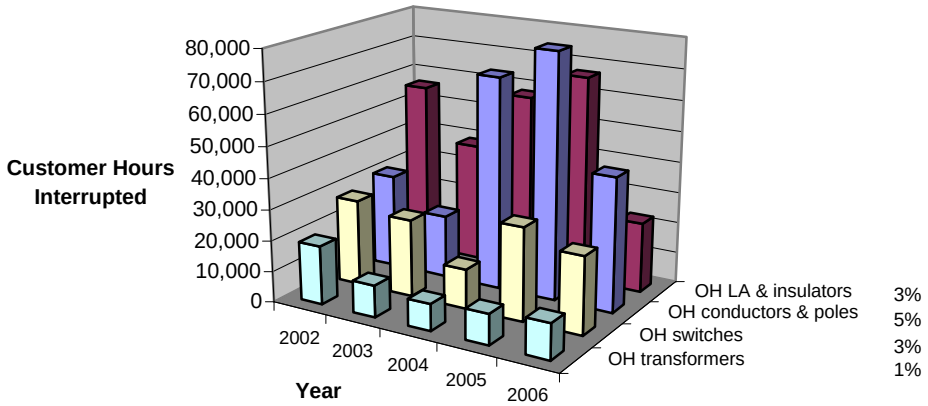
The top contributors to for defective equipment CI in 2006 were: Underground Cable (13 percent); Overhead Conductor and Poles (5 percent); Overhead Switches (5 percent); Underground Switches (5 percent); Lighting Arrestors and Insulators (4 percent); Elbows, Terminators and Potheads (4). These are key capital investment areas identified for reliability improvement.

Chart 5 - Overhead Equipment CI Performance (MED excluded)



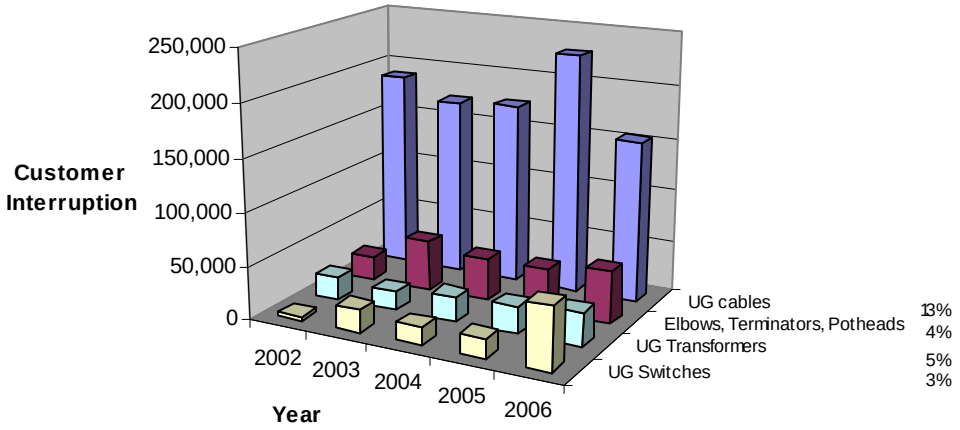
	2002	2003	2004	2005	2006
OH transformers	10,445	6,786	10,075	5,839	13,517
OH switches	44,996	45,531	28,285	40,304	65,881
OH conductors & poles	46,333	26,382	80,924	72,840	57,935
OH LA & insulators	58,558	58,965	82,639	90,150	53,135

Chart 6 - Overhead Equipment CHI Performance (MED excluded)



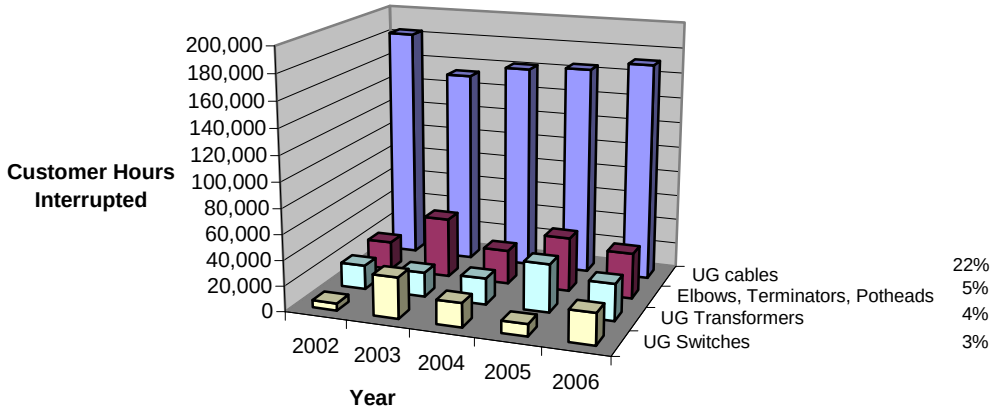
	2002	2003	2004	2005	2006
OH transformers	18,954	10,252	8,619	9,848	11,432
OH switches	27,810	24,990	12,809	29,971	24,866
OH conductors & poles	30,490	20,295	68,569	79,022	43,176
OH LA & insulators	56,142	38,808	57,880	66,864	22,715

Chart 7 - Underground Equipment CI Performance (MED excluded)



	2002	2003	2004	2005	2006
UG Switches	3,719	21,935	16,887	18,191	59,405
UG Transformers	21,726	17,894	23,931	25,939	31,608
Elbows, Terminators, Potheads	22,290	47,912	40,552	40,893	49,301
UG cables	188,507	169,948	173,340	228,044	153,494

Chart 8 - Underground Equipment CHI Performance (MED excluded)



	2002	2003	2004	2005	2006
UG Switches	5,579	32,167	18,866	9,348	24,506
UG Transformers	18,986	19,293	20,788	37,984	28,967
Elbows, Terminators, Potheads	22,499	46,977	26,759	42,561	35,921
UG cables	183,521	152,723	161,559	164,665	171,470

Unknown Cause Reliability Analysis

Unknown Cause is defined as customer interruptions with no apparent cause or reason, which could have contributed to the outage. Experience indicates that the majority of Unknown Cause interruptions are occasioned by Tree or Animal Contact.

Charts 1 and 2 show the Unknown Cause reliability contribution in 2006 was 12 percent for CI and 4 percent for CHI.

Tree Contact-Cause Reliability Analysis

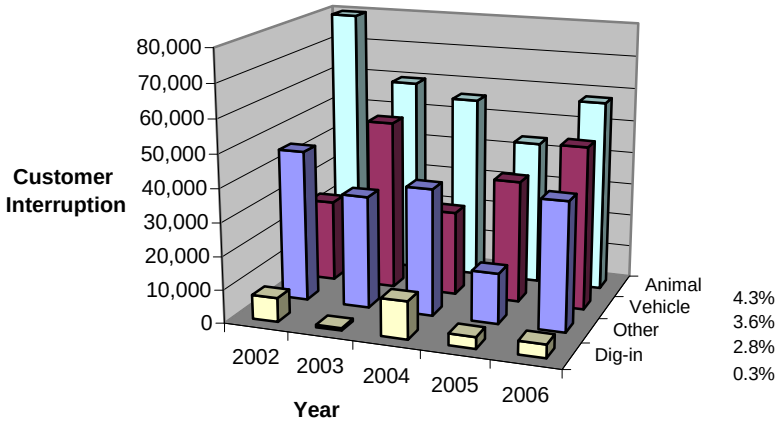
Charts 1 and 2 show that Tree Contact-Cause interruptions have increased steadily from 2002 to 2006. In 2006, Tree Contact-Cause contributed to 11 percent of the total System CI and 15 percent of the total CHI.

In 2007, THESL increased its budget for Vegetation Management budget from $2.1M to $3.5M. THESL is in the process of transitioning to Reliability-Based tree trimming instead of the traditional fixed trimming by area on a set frequency. The new Vegetation Management model will take into account different tree species, their growth rate, their reliability impact and set up a program that will have the greatest impact per dollar spent. In the future, THESL will monitor very closely all tree-related outages and investigate their cause along with “last trimmed” information to determine when the trees along a particular feeder or in a particular area should next be trimmed. The new Vegetation Management Program is expected to be in place in 2008.

Foreign Interference Cause Reliability Analysis

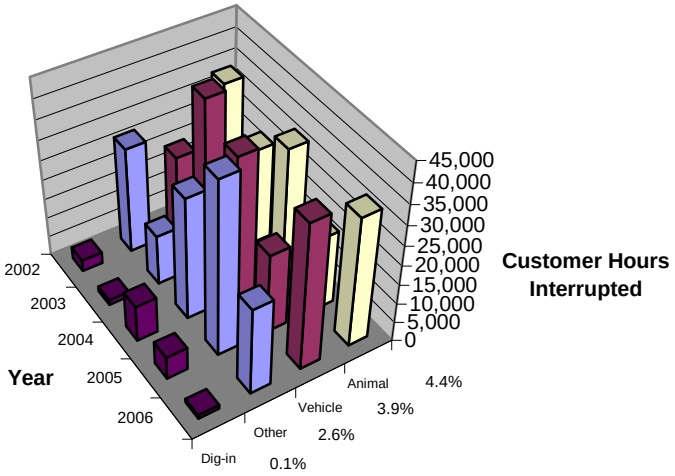
THESL tracks detailed causes of Foreign Interference by internal Sub-secondary Cause Codes. Charts 9 and 10 show the CI and CHI performance of the detailed causes of Foreign Interference for 2002-2006. The top causes for Foreign Interference are Animal and Vehicle.

Chart 9 - Foreign Interference CI Performance (MED excluded)



	2002	2003	2004	2005	2006
Dig-in	7,220	735	11,264	3,440	4,025
Other	45,600	33,857	38,169	15,186	38,607
Vehicle	24,751	51,358	25,521	36,919	49,121
Animal	79,694	59,632	55,702	43,734	57,861

Chart 10 - Foreign Interference CHI Performance (MED excluded)



	2002	2003	2004	2005	2006
Dig-in	2,923	1,273	9,262	5,839	1,001
Other	26,978	12,803	31,141	43,948	22,235
Vehicle	19,873	41,920	36,018	20,319	37,238
Animal	33,864	24,596	32,883	18,714	33,029

INTRODUCTION

Exhibit C1 provides evidence under Tabs 2 through 7 on a number of different policy areas as set out below.

Tab 2 describes THESL's corporate re-structuring initiative. As a result of this restructuring, many corporate services previously located in THC now reside in THESL.

Tab 3 describes THESL's implementation of OEB directives concerning shared service pricing and time-based cost allocation.

Tab 4 concerns business planning. Schedule 1 and its appendixes describe the typical business planning process as well as the process underlying the financial projections used in this Application and the associated assumptions. Schedule 2 sets out the macro-economic variable forecasts used as inputs to the business planning process. Schedule 3 describes the internal cost-allocation model used to distribute vehicle, facilities, and IT costs to the THESL departments and affiliates receiving those services.

Tab 5 provides the current THESL Conditions of Service document together with a spreadsheet annotating the latest revisions to that document.

Tab 6 describes the long-term distribution system planning process covering sustaining and reactive capital investment plans.

Tab 7 describes THESL's short-term distribution work program prioritization process including the asset investment strategy software and the prioritization scoring criteria.

SHARED SERVICES MODEL

In its April 12, 2006 EB-2005-0421 Decision with Reasons, the OEB directed THESL to develop a time-based shared service allocation methodology for non-direct corporate costs. The OEB also directed THESL to provide a detailed report on the allocation rationale and methodology as part of THESL's next rate application.

At the time of the OEB Decision, shared services were centralized in THC, which provided and charged these services to each subsidiary. Pursuant to the OEB Decision, THC re-organized its corporate structure such that many of the transactional and support shared services were moved from THC into THESL. This was designed to minimize the number of shared services and inter-affiliate transactions, to develop a high level of autonomy amongst affiliates, to provide for greater regulatory clarity and to allow for a higher degree of transparency of costs in THESL and THC. In addition, THESL implemented a corporate-wide approach to ensuring compliance with the OEB requirements for allocating the cost of shared services. Significant departmental level resources were assigned to this initiative, and a Steering Committee comprised of senior THC and THESL staff was established along with a Project Team under the sponsorship of the CFO. The Project Team included staff from THC and THESL, and a subject matter expert in an advisory capacity. THESL also committed to continuing oversight activities such as periodic reviews and updating of data and management approval to ensure continued compliance with the OEB requirements. The activities and results of the Project Team are described in Exhibit Q1, Tab 1, Schedule 1.

The Project developed in two phases. Phase I dealt with the allocation methodology and included a detailed inventory of affiliate company service transactions. These transactions are listed in Exhibit Q1, Tab 2, Schedule 1. Each service transaction was reviewed to determine the costing formula and a method to fairly allocate the cost of

services to affiliates. In addition, criteria for identifying potential fair market value comparisons for each service were established, where possible.

In Phase II, the Project Team implemented the new methods and applied newly collected data in the preparation of the 2007 transfer pricing and Service Level Agreements ("SLAs"), which can be found in Exhibit Q1, Tab 3, Schedules 1-6. An independent review identified numerous useful enhancements, which were incorporated across the methodology phase deliverables and into the subsequent implementation phase to ensure compliance with the OEB Decision. A copy of this report can be found in Exhibit Q1, Tab 4, Schedule 1.

SHARED SERVICE PRICING AND COST ALLOCATION

The OEB Decision in EB-2005-0421 directed THESL to implement an improved time-based methodology. THESL used this opportunity to also undertake a full review of affiliate transactions transfer pricing and compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters ("ARC"). Following the development of the Inventory of Transactions, the Project Team defined parameters for the application of fair market value ("FMV") and cost-based pricing ("CBP"). In establishing the price of a transaction, THESL followed the ARC protocol that requires the use of FMV pricing where available, and CBP where FMV is not available. THESL initially determined the approximate cost of providing its service, resources and products at the Department level provided in the 2007 budget. Costs were calculated, according to the ARC requirement, to include direct operating costs, indirect operating costs and capital costs.

THESL commissioned an independent review to examine current approaches and key regulatory decisions in energy sector cost allocation, and the frameworks used to allocate services, resources and product prices for transactions. The Project Team developed the cost allocation based on a fully revised Inventory of Transactions actual costs, and FMV data; THC and THESL each conducted time studies in order to obtain the information necessary to allocate the costs of shared services, as required by the OEB decision and in accordance with current industry practice.

Detailed information on the cost allocation method, fair market valuation and time studies can be found in Exhibit Q1, Tab 1, Schedule 1.

Finally, as mandated by the ARC, SLAs were developed to manage inter-affiliate shared services. These agreements include a legal contract with an appendix that lists the services covered by the agreement. The agreements were constructed using information

drawn from the Shared Service Model and include the name, description, type, quantity and quality of service for each shared service transaction, the pricing mechanism (FMV or CBP) and the cost allocation mechanism. The SLAs are filed at Exhibit Q1, Tab 3, Schedule 1-6.

BUSINESS PLANNING PROCESS

The business planning process is performed annually and involves key personnel from all levels of management. The process begins in the second quarter of each year with a review of prior year results and ends late in the year with approval of the business plan by THESL's Board of Directors. The results of the activity include a detailed budget for the upcoming year and a general plan for the four subsequent years. The typical business planning process is detailed in Appendix A to this schedule.

In February 2007, a separate process was initiated to determine the financial projections that form the foundation of this distribution rate application. This process is described in Appendix B to this schedule. Although separate from the annual business planning cycle, this activity included strict review and approval controls, and oversight and approval from executive management, while utilizing the best information available at the time of preparation.

The assumptions and related discussion underlying the 2008-2010 financial projections that form the basis of the revenue requirement are filed in Appendix C to this schedule.

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memo

date	February 19, 2007
attention	Executives, Managers, and Supervisors of Toronto Hydro-Electric System Limited
from	JS Couillard, Chief Financial Officer
subject	Business Planning Process

Introduction

In the second quarter of each year, Toronto Hydro-Electric System Limited ("THESL") begins a full business planning review process. The exercise is comprised of a detailed plan for the upcoming year and a more general plan for the four subsequent years. Upon final approval by the Board of Directors of THESL, this plan is consolidated at the corporate level and filed with the shareholder (the City of Toronto), 30 days before the end of the year in accordance with Toronto Hydro Corporation's ("THC") Shareholder Direction from the City of Toronto ("City").

This document describes the typical business planning process.

Annual Planning Process

THESL's annual planning process follows the following general timeline:

1. Review of prior year results	January - February
2. Establishment of strategic goals and objectives for the next planning horizon by THESL Executive team	March – April
3. Approval of strategic goals and objectives by THESL's Board of Directors	May

4. Engagement and communication of approved strategic goals and objectives to employees	May
5. Preparation of assumptions for investment plan and operating and maintenance requirements by business units	June – July
6. Preparation of a business plan including detailed budget for the upcoming year and long-term projections for the following four years	August – September
7. Executive review of proposed plan with business unit leaders	October
8. Approval of the overall five-year business plan by THESL's Board of Directors	November

1. Review of Prior Year Results

The review of prior year results is the first step to derive the business plan and attendant strategic goals and objectives for the next year. During this process, senior management reviews the performance of each business unit and assesses the challenges and issues faced in the prior year. Following this review, senior management establishes a list of initiatives to be considered when determining the upcoming plan. The review of prior year results as well as the list of initiatives and the review process is guided by the Corporation's strategic vision and "road map".

2. Establishment of Goals and Objectives

From its review of prior year results, senior management assesses all significant current initiatives and the need for new initiatives to fulfill its mandate with regard to Customer Service, Investment in Infrastructure, Health and Safety, and Financial Performance.

At the conclusion of this process, THESL's executive management agree on the overall strategy for the next planning horizon (five years) and on the underlying initiatives required to meet the related goals and objectives. THESL executives also ensure that the requirements of City's Shareholder Direction to THC are aligned with the proposed strategy.

3. Approval of Strategy

The overall strategy and the underlying goals and objectives of THESL are presented to THESL's Board of Directors by the President of THESL during a strategic session in May. The Board's approval of the overall strategy is required to proceed with the elaboration and execution of the business plan.

4. Engagement and Communication

The Board-approved strategic goals and objectives are communicated to employees prior to the detailed preparation of the business plan to ensure proper alignment by each of THESL's business units.

5. Preparation of Plan Assumptions

The main assumptions underlying the business plan process are derived by the business units following an in-depth analysis of their own initiatives and projects. Business unit assumptions are guided by the following centralized assumptions.

Economic Outlook Assumptions

The economic outlook assumptions have a direct impact on expenditures, business growth, and required investments. The determination of the economic outlook and related assumptions are prepared by the Finance team and encompasses assumptions respecting load growth, labour and benefits escalation rates, income taxes, short-term and long-term interest rates and the Consumer Price Index.

The impact of these economic assumptions are communicated to each business unit but are inputted directly by Finance into the corporation's business planning model to ensure consistency.

Investment Plan

During the 2006 EDR process, THESL submitted evidence indicating that THESL intended to commission an Asset Condition Assessment ("ACA"), and produce a 10-year infrastructure Capital Plan. During that proceeding, testimony was given indicating that a significant increase in investment would be required to refurbish the overall distribution plant to maintain service to customers to acceptable safety and reliability standards. THESL's 10-year Capital Plan to modernize its assets was approved by THESL's Board of Directors in 2006 and was incorporated as a cornerstone of the Corporation's 2007-2011 business plan.

THESL's ACA was undertaken by an independent third-party engineering consulting company, Kinetrics Inc. Kinetrics Inc. was tasked with carrying out an ACA for a sub-set of THESL's distribution plant. The ACA and the 10-year Capital Plan lead to the same high-level conclusions, that is, THESL will need to spend a significant amount to refurbish large portions of its distribution plant over the next 10 years.

As with any long-term plan, the overall assumptions underlying the plan will be re-visited annually, by THESL's Asset Management Division to ensure alignment. The detailed investment plan for the upcoming year will then be derived in a rigorous manner using an in-house work prioritization model. The amount of work to be performed during the period will consider available resources (both human and capital), and incremental load requirements all within acceptable risk tolerances. Business cases will be produced to support all major initiatives.

Operating and Maintenance Programs

The maintenance program is derived in conjunction with the condition assessment of the assets and the operating requirements of the assets. The Asset Management Division determines maintenance requirements for its assets for the upcoming year using models and assumptions that factor expected useful life, load, historical failure rates, environment health and safety laws and regulations, manufacturers' operating and maintenance instructions, insurance underwriters' recommendations and acceptable risk tolerances.

The operating plan includes support from Toronto Hydro Corporation to THESL. To this end, the operating plan includes expenditures related to Governance, Information Technology, Customer Services, Environment Health and Safety, Finance, Human Resources, Legal and Corporate Communication.

6. Preparation of Budget

Following the preparation of the investment plan and the operating and maintenance programs, Toronto Hydro enters into the more detailed budgeting phase of the business plan. Each business unit performs this exercise at a responsibility center level, and the process results in a detailed calculation of revenue and expenditures (operating and capital) for the upcoming year. The budgeting phase focuses on near-term objectives and uses assumptions derived from the previous phase. The major activities included in this phase are:

- Load Forecasting
- Other revenue budgeting
- Operating budget calculation
- Interest and financing charges and interest income review
- Depreciation calculation
- Payment in lieu of income taxes ("PILs") calculation
- Capital expenditure budgeting

The end result of the budget process is a detailed plan for the upcoming year. Following the preparation of this detailed plan, assumptions are used to derive a high level plan for the following four years. The assumptions used are mainly related to THESL's long-term investment plan, long-term operating and maintenance programs, cash requirements, staffing requirements, changes in operating practices, economic growth indicators, and weather history.

7. Executive Review of Business Plan

After completion of the budgeting phase, the CFO and the President of THESL chair a budget review process whereby executives present their respective budget for the upcoming year and the main assumptions for the following four years. A detailed review is then undertaken by the CFO and the President of THESL to ensure the business plan as presented is aligned with the strategic goals and objectives. Following this review, the business plan and related assumptions will be presented to the President and Chief Executive Officer of THC for final approval.

A final business plan is then derived for presentation to and approval by the Board of Directors.

8. Board Approval of Business Plan

In November, the President of THESL presents the business plan to the Board of Directors for discussions and approval. Following the presentation, members of the Board of Directors may request additional information and modifications to plan. Once satisfied, the Board of Directors approves the business plan.

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toronto hydro electric system

memo

date	February 19, 2007
attention	Executives, Managers, and Supervisors of Toronto Hydro-Electric System Limited
from	Asheef Jamal, Controller
subject	2008–2010 EDR Application – Financial Projections

Background

This document is intended to provide guidelines for the preparation of the financial projections which will form the basis for Toronto Hydro-Electric System Limited's ("THESL") Electricity Distribution Rate ("EDR") application filing with the Ontario Energy Board ("OEB").

For the upcoming EDR application to be filed in 2007, THESL will be submitting projections for three years - 2008, 2009, and 2010 (the "filing period"). This document will include a description of the process used to gather financial data and general assumptions used to prepare the financial projections for the EDR application ("the projections").

Since the usual business planning timelines do not coincide with the OEB's timing requirements with respect to the EDR application preparation of the EDR projections, THESL's approach and timing will be modified to accommodate the EDR project timelines. The underlying principals of the standard business planning process[1], with respect to due diligence and review, will be maintained during the preparation of the projections.

These projections will be based on the detailed 2007 business plan, as approved by the Board of Directors of THESL in November 2006, and on the actual operating results for the

[1] Refer to the February 15, 2007 memorandum from the Chief Financial Officer titled "Business Planning Process" for additional information.

year ended December 31, 2006. They will also incorporate the best known information at the time of preparation.

Process

In order to derive the costs for 2008 to 2010 projections, Finance will require support of all business units. The process will be as follows:

- Finance will create forms in Hyperion Planning which resemble the standard budgeting templates to facilitate the collection of projected amounts.
- The Hyperion Planning forms will display the 2007 budgeted balance for reference.
- To facilitate accurate OEB reporting, revenue and expenditures will need to be captured at the full (13-digit) Ellipse general ledger code level.
- The responsible persons for each business unit will populate the forms within the communicated timelines
- The business units are required to provide related explanations and support.
- THESL Executives will be formally approving the projected amounts and underlying assumptions.

Refer to the plan and timelines previously distributed.

Specific Aspects

<u>Electricity Net Revenue</u>

The Rates department will be accountable for the calculation of distribution revenue and net power revenue. This activity will be completed after business unit (operational) data has been collected as the operational data underlies the revenue requirement calculation.

The distribution revenue variables include:

- Normal weather conditions
- Expected service area/customer growth
- Revenue requirements per the regulatory model (expenditures and return)

Other Revenues/Income

The projected other revenues/income will be based on the 2007 expected levels plus/minus any adjustments expected during the filing period. The initial assumption is that other income will remain fairly consistent over time and that an increase in rates (from regulated charges) is not expected.

The Finance department will coordinate the gathering of supporting documentation from business units including the explanation of variances to prior years. Note that each business unit responsible for other revenue/income transactions will need to provide the appropriate information to support the balances and variances.

Operating Expenses

Operating expenses are divided into the following major categories:

- Compensation (Payroll) Costs
- Labour and Vehicle Costing
- Vehicle/Fleet Costs
- Direct Materials, Support, and Service Costs
- Usage Charges
- Shared Services Allocations and Recoveries

Compensation (Payroll) Costs

The assumptions for all THESL compensation costs will be determined by the Organizational Effectiveness ("OE") department in conjunction with information provided by the operational leaders. Projected headcount data will be centrally managed by OE and aligned with the long-term capital plan. The following summarizes the process for the determination of related assumptions:

Headcount (Staffing Requirements)	The existing long-term THESL operational staffing plan will be used as a basis for the determination of staffing requirements. All other areas not covered by staffing plan will be reviewed by OE with business unit executives. Any incremental staffing requirements not already approved will require the approval of the President of THESL.

Salaries	For non-union staff, the salary increase for the filing period will be based on market rates as projected by OE. For union employees, the compensation changes will be based the current agreement with CUPE for 2008 and on management expectations for the renewal for 2009 and 2010.
Benefits	Based on recent trends to be validated by Morneau Sobeco for post-employment benefits.
Vacation	Based on recent trends.
Overtime	To be determined by business units and should reflect the planned work programs and investment plan.
Shift Premiums	Based on recent trends.
Sick Leave	Based on recent trends.
Other	Other costs related to compensation expense will be based on recent trends and/or supported by business units or OE.

For reference, related costs are coded to the following expense element series: 3xxx.

Labour and Vehicle Costing

Capitalization of labour will be determined by projects and programs that utilize internal labour. Business Transformation ("BT") will work with the other operational units and Finance to provide the appropriate information and ensure that the investment plan and work program is appropriately reflected.

For reference, related costs are coded to the following expense element series: 4031, 4032, and 4xxx.

Vehicle/Fleet Costs

Lease and fuel charges including maintenance and other charges related to the vehicles will be provided by the business units with input from the Fleet department. The fleet-related projections will be aligned to established capital plan.

For reference, related costs are coded to the following expense element series: 62xx and 9906.

Direct Materials, Support, and Service Costs

Expenditure types included in this category include materials, other goods, and external services to support projects and programs as well as administrative and operating/support activities. Consider specific and significant fees incurred including those related to the Independent Electricity System Operator (the "IESO"), the OEB, and other regulatory agencies.

A portion of goods and services purchased are consistent from year to year due to the repetitive nature of our business. As a result, an inflation index or consumer price index ("CPI") will be applied to those standard costs that are expected to recur. The projected CPI rates are as follows:

Year	CPI Rate[2]
2008	2.3%
2009	2.4%
2010	2.1%

For reference, related costs are coded to the following expense element series: 5xxx, 60xx, 61xx, 63xx, 64xx, and 65xx.

Usage Charges

Internal allocation of charges between THESL business units. This includes occupancy costs, IT charges, and laboratory services.

The underlying assumptions will, for the most part, be the same as those used in determining the projections at the end of 2006.

For reference, related costs are coded to the following expense element series: 992x.

Shared Service Allocations and Recoveries

Shared services costs will be allocated to and from THESL. These costs will primarily relate to governance, corporate finance, treasury, taxation, internal audit, and financing. Shared service costs to be recovered by THESL for services rendered to other affiliated companies will be analyzed by Finance in connection with support provided by the

[2] Source: Conference Board of Canada.

business units. These recoveries will mainly relate to facilities, vehicles, and IT infrastructure.

All services provided to and from THESL should be supported by service level agreements and related supporting documentation.

For reference, related costs are coded to the following expense element series: 99xx.

Interest and Financing Charges

Interest and financing charges will be derived by the Treasury department for the filing period. Interest income will be derived using expected cash balances. Interest expense and financing charges will be based on expected levels of debt (reflecting the note payable to THC and other THC financing activities). Other aspects include costs related to parental guarantees, letters of credit, lines of credit, interest on regulatory assets and liabilities, and allowance for funds used during construction ("AFUDC").

Depreciation

The depreciation balance for the filing period will be based on the budgeted book value of assets at the end of 2007 plus the impact of the expected capital investment during the period, as aligned with the capital plan. Business Transformation and Finance will be responsible for determining the depreciation expense related to the distribution system assets.

THESL will assume that the smart meters deferral balance will be transferred to fixed assets in 2007 and that the 'traditional meters' will be kept in the rate base until fully depreciated.

PILs

Payment in lieu of income taxes ("PILs") will be determined by using the established THESL tax model which reflects the most recent tax rules and regulations. The PILs estimate will reflect prudent tax planning assumptions. The Finance department will be responsible for calculating the 2008-2010 PILs projections.

Capital Investment Plan

The capital investment plan for the 2008 to 2010 period will be based on the 10-year asset infrastructure investment plan approved by the Board of Directors in August 2006. The investment plan will be updated to reflect the near-term objectives. The costs assumptions should include productivity improvements and changes in compensation and cost for material. The Asset Management department will be responsible for preparing this portion of the capital investment plan.

Other capital expenditures related to IT, smart meters, facilities, and fleet will be prepared by the respective business units. Appropriate documentation including business cases and variance analysis are required to support these costs.

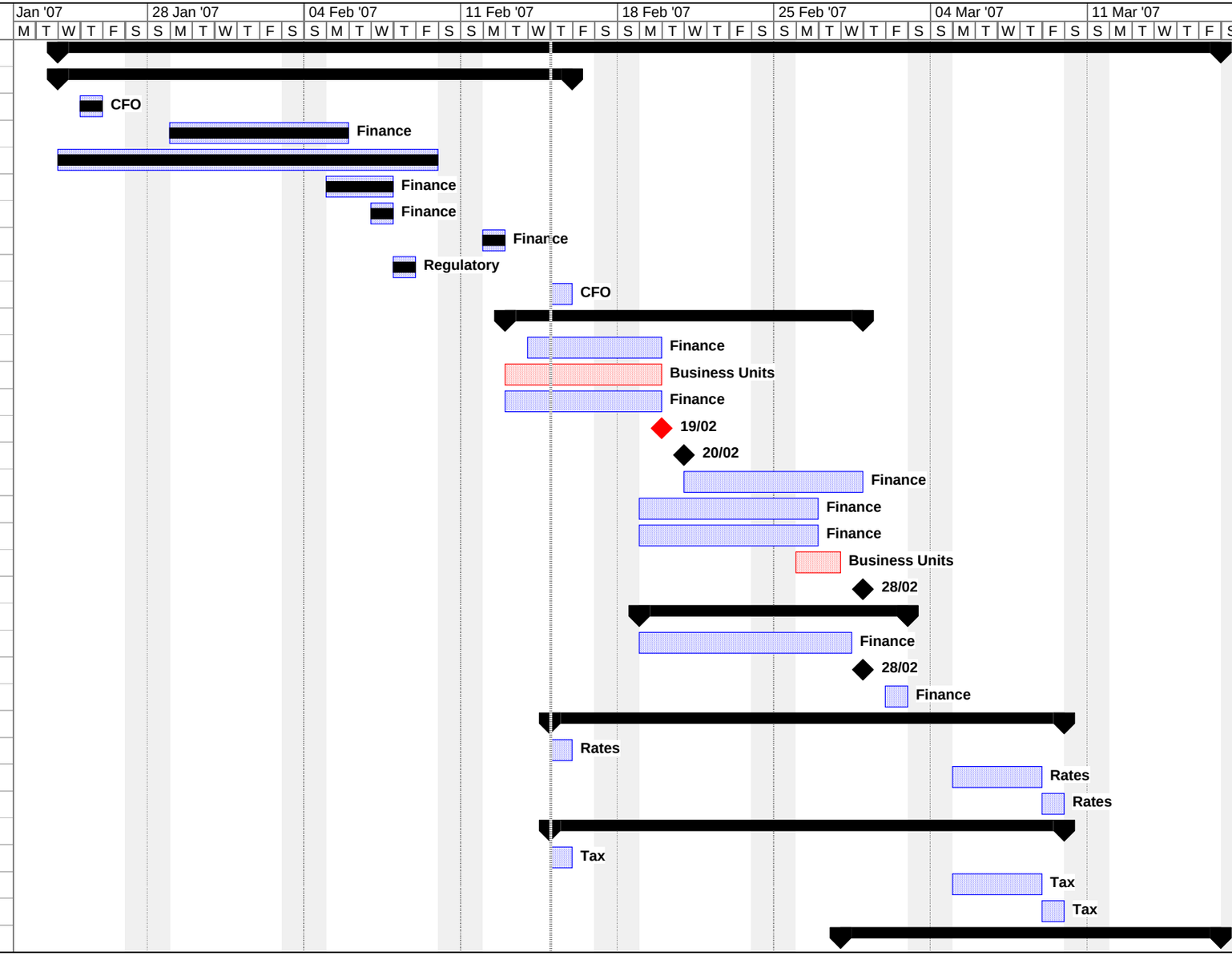
The CIO will oversee the overall IT investment plan and related expenditure projections. Executives with capital investment budgets will be required to support the proposed initiatives and formally sign-off on the plans.

Approvals

Before the projections and assumptions are finalized, they will be reviewed at various levels. The levels of review and approval are as follows:

- Business Unit review with Finance
- Business Unit Executive approval
- Executive review with THESL President and CFO
- THESL President and CFO approval
- THC President and Chief Executive Officer approval

ID	Task Name
1	**THESL EDR 2008-2010 Projections**
2	**Planning and Communication**
3	Initial Communication to EDR Team
4	Hyperion Forms, Reports, and Process Development
5	Ellipse/OEB Code Mapping
6	Align Finance-Ops Requirements
7	Align Finance-Rates/Regulatory Requirements
8	Align Finance-OE/HR Requirements
9	Process Overview - Communication to EDR DRP's
10	Process Overview - General Communication
11	**Data Gathering - Round 1**
12	Business Unit Training and Hyperion Form Roll-out
13	Data Input & Assumptions Listing (CapEx, OpEx, DB)
14	Build Documentation File
15	Data Gathering Cutoff (Hyperion Locked)
16	Distribute Initial Reports/Feedback to Business Units
17	Data Consolidation and Analysis
18	Calculation of Depreciation
19	Determination of Shared Services
20	Business Unit Feedback
21	Distribute Data to Rates and Tax
22	**Data Gathering - Round 1 (Balance Sheet)**
23	Data Gathering and Input
24	Distribute Data to Rates and Tax
25	Review Documentation File
26	**Rates Determination**
27	Provide Rates Requirements to Finance
28	Run Rates Model and Determine Projected Rates
29	Input Data Into Hyperion
30	**Tax Determination**
31	Provide Tax Requirements to Finance
32	Run Tax Model and Determine Projected Tax Rates
33	Input Data Into Hyperion
34	**Review and Approval Process**



Project: 2008-2010 Projections Proces
Date: 15 Feb '07

Task | Progress | Summary | External Tasks | Deadline
Split | Milestone | Project Summary | External Milestone

BUSINESS PLANNING – ASSUMPTIONS

INTRODUCTION

Following is a summary of key assumptions related to THESL's financial projections included in the application.

ECONOMIC

Table 1: Interest and Bond Rates[1] (%)

	2007 Bridge	2008 Test	2009 Test	2010 Test
3-Month T-Bills	4.20	4.42	4.42	4.42
90-Day Commercial Paper	4.38	4.72	4.79	4.83
Prime Rate	6.00	6.23	6.25	6.25
1-3 Year Bonds	4.09	4.53	4.65	4.70
3-10 Years Bonds	4.27	4.72	4.90	5.00
10+ Years Bonds	4.25	4.81	5.11	5.29

Table 2: Other[2]

	2008 Test	2009 Test	2010 Test
CPI	2.3%	2.4%	2.1%
Cdn$/US$ Exchange Rate	1.143	1.152	1.165

[1] Source: Conference Board of Canada. Forecast Date: December 16, 2006.
[2] Source: Conference Board of Canada

TAX RATES

Table 3: Tax Rates (%)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Federal Tax Rate[3]	21.00	21.00	20.50	20.00	19.00
Federal Surtax Rate[4]	1.12	1.12	Nil	Nil	Nil
Ontario Tax Rate[4]	14.00	14.00	14.00	14.00	14.00
Total Statutory Tax Rate	36.12	36.12	34.50	34.00	33.00
Large Corporations Tax Rate[4]	Nil	Nil	Nil	Nil	Nil
Ontario Capital Tax Rate[5]	0.300	0.285	0.285	0.225	0.150

COMPENSATION

Table 4: Full Time Equivalent ("FTE")

(Number of FTE)	2007 Bridge	2008 Test	2009 Test	2010 Test
Total	1,609.0	1,665.5	1,719.8	1,711.4

Table 5: Payroll Burden Rate (%)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Benefit Burden Rate[6]	28.1	27.8	28.2	28.6

CAPITAL EXPENDITURES

Table 6: Allowance for Funds Used During Construction ("AFUDC") (%)

	2007 Bridge	2008 Test	2009 Test	2010 Test
AFUDC Rate (as per OEB prescription rate for Q1 2007)	4.72	4.72	4.72	4.72

[3] Attributable to the purchase of Smart Meters in 2007.
[4] Source: 2006 Federal Budget.
[5] Source Ontario Corporations Tax Act.
[6] Percentage of base pay related to payroll benefits (including medical, dental, post-employment benefits, long-term disability, life insurance, pension, and workers compensation).

Calculated on quarterly construction work in progress ("CWIP") closing balance for distribution plant net of capital construction.

Depreciation and Amortization Rates

The amortization rates outlined in Appendix B of the 2006 Electricity Distribution Rate Handbook[7] ("DRH") published by the OEB are applied to historical and projected capitalized expenditures.

The DRH is silent on the amortization rates related to capitalized software. THESL's Computer Software Capitalization Policy describes the accounting policy and recommended treatment for software expenditures. Paragraph 1.6 of this policy outlines the amortization period applicable to capitalized software costs. Refer to Exhibit D1, Tab 13, Schedule 1, Appendix A for a copy of this policy.

Land rights are amortized over 50 years.

Capital expenditures related to smart meter implementation are amortized over 15 years beginning January 2008.

REVENUE

Distribution Revenue

Assuming "normal" weather conditions based on historic weather patterns.

[7] Dated May 11, 2005.

CUSTOMER AND SERVICE AREA

Table 7: By Class

	2007 Bridge	2008 Test	2009 Test	2010 Test
Residential	604,842	629,617	659,663	700,310
General Service <50kW	66,961	66,906	66,850	66,795
General Service 50kW -1000kW (non - interval)	2,671	1,600	530	0
General Service 50kW - 1000kW (interval)	8,900	10,001	11,076	11,558
General Service 1000kW - 5000kW	525	532	539	547
Large Users	49	49	49	49
Total	683,947	708,705	738,708	779,259

Service Area

Assuming no significant changes to service area.

REGULATORY

Table 8: Carrying Charges (%)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Carrying Charge Rate[8]	4.59	4.59	4.59	4.59

OPERATIONAL

Table 9: Operational (%)

	2008 Test	2009 Test	2010 Test
Inventory Surcharge	10.66	10.74	13.09
Vehicle Surcharge[6]	6.65	12.53	16.97

[8] Based on the OEB-prescribed rate for the second quarter of 2007.

Smart Meters

Capital and operating expenditures related to the Smart Meter initiative incurred in 2006 and 2007 are deferred (to a regulatory asset account) until January 2008.

Assumed full recovery of smart meter expenditures as at January 2008.

ECONOMIC FORECAST

Toronto Hydro subscribes to the Conference Board of Canada's Metropolitan Outlook service for forecasts of economic activity in the Company's franchise area. The Conference Board report, issued December 2006, is attached as Appendix A to this schedule.

A summary of economic conditions over the forecast period is contained in the following table:

Table 1: Toronto Economic Indicators

	GDP Growth	Consumer Price Index Growth	Population Growth	Employment Growth	Unemployment Rate	Retail Sales Growth	Housing Starts (000's)
2005	3.4%	1.8%	1.7%	2.1%	7.0%	4.6%	41.6
2006	2.3%	1.8%	1.7%	1.3%	6.6%	3.0%	38.1
2007	2.9%	1.3%	1.9%	1.6%	7.0%	5.7%	39.0
2008	4.0%	2.3%	1.9%	2.7%	7.0%	6.2%	39.8
2009	4.1%	2.4%	1.9%	2.6%	6.9%	6.4%	41.4
2010	4.1%	2.1%	2.0%	2.6%	6.8%	6.3%	43.0

Source: Conference Board of Canada, December 2006

Toronto Hydro-Electric System Limited
EB-2007-0680
Exhibit C1, Tab 4, Schedule 2, Appendix A
Filed: 2007 Aug 2

The Conference Board of Canada
Insights You Can Count On

Metropolitan Outlook 1 Winter 2007

Economic Insights Into 27 Canadian Metropolitan Economies

ECONOMIC PERFORMANCE AND TRENDS

The Conference Board of Canada
Insights You Can Count On

Metropolitan Outlook 1: Economic Insights Into 27 Canadian Metropolitan Economies
by *Mario Lefebvre, Alan Arcand, Greg Sutherland, Lucie Tremblay* and *Maxim Armstrong*

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This Issue

Book 1 covers Halifax, Québec City, Montréal, Ottawa–Gatineau, Toronto, Hamilton, Winnipeg, Regina, Saskatoon, Calgary, Edmonton, Vancouver and Victoria.

Book 2A deals with St. John's, Saint John, Saguenay, Oshawa, Kitchener, Windsor and Kingston.

Book 2B deals with Trois-Rivières, Sherbrooke, St. Catharines–Niagara, London, Sudbury, Thunder Bay and Abbotsford.

This publication is available through the Internet at www.conferenceboard.ca/edata.htm. For more information about the forecast, please contact our Information Specialists at 613-526-3090 ext. 444 or e-mail metro@conferenceboard.ca.

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Canada 1

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Toronto 4

Highlights

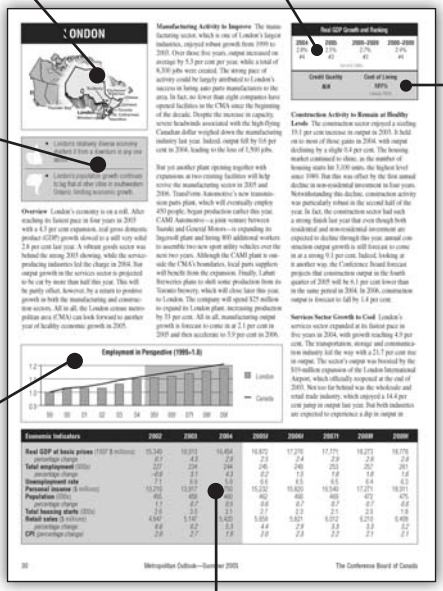
- **Toronto**'s real GDP growth will be 2.9 per cent in 2007, but better results are expected over the medium term.

Map
The census metropolitan areas (CMAs) are composed (defined by Statistics Canada) of the main city and the surrounding municipalities, towns, townships, villages and parishes. The map shows the position of the CMA relative to other CMAs within the province.

Thumbs Up (Thumbs Down)
A thumbs up (down) indicates a favourable (unfavourable) element/event that has occurred within the census metropolitan area or that will certainly occur in the near future. It can also indicate a positive (negative) economic climate within the CMA.

Employment in Perspective
Using a base year (1996, for example) as a benchmark, this graph plots total employment growth against time. The shaded area of the graph represents the forecast horizon, and the forecast years are marked by the letter "f." The value 1.0 is given to the base year, and each subsequent year is used as a comparison; hence, the growth is clearly schemed. For analytical purposes, employment in perspective is shown with metropolitan and Canadian data. Canadian employment growth is represented by a line graph, while CMA employment growth is depicted by a bar graph.

Real GDP Growth and Ranking
The table displays four GDP growth rates: the last historical year, the current forecast year, the rest of the forecast period, and finally, a ten-year period comprising both historical and forecast data. Below each growth rate is a ranking that shows how the CMA fares against the other census metropolitan areas featured in the current edition of the *Metropolitan Outlook*.



Credit Quality
The credit rating is a current opinion (e.g., Dominion Bond Rating Service or Standard & Poor's) of the city's overall financial capacity (its creditworthiness) to pay its financial obligations. The rating applies to one of the individual cities within the CMA.

Debt Rating Service Scales

Dominion Bond Rating Service

Highest credit quality	AAA
Superior credit quality	AA
Satisfactory credit quality	A
Adequate credit quality	BBB
Speculative	BB
Highly speculative	B
Very highly speculative	CCC

Standard & Poor's

Highest quality	AAA™
Very good quality	AA
Good quality	A
Medium quality	BBB
Lower medium quality	BB
Poor quality	B
Speculative quality	C
Default	D
Rating suspended	Suspended

Cost of Living
Here the cost of living is shown as a ratio comparing the consumer price index (CPI) level of the CMA and that of Canada.

Economic Indicators

Industrial Classification
Statistics Canada compiles data on gross domestic product and employment following the North American Industrial Classification System (NAICS). Within this system, two aggregate sectors exist—goods and services—each of which is subdivided into industrial sectors based on major type of production activity. The goods-producing sector includes the primary, manufacturing, construction and utilities industries, whereas the services sector aggregates transportation and communication; wholesale and retail trade; finance, insurance and real estate; commercial services; non-commercial services; public administration; and defence.

Real GDP at Basic Prices
Gross domestic product at the CMA level is calculated using a weighted share of employment in both the CMA and the province and in provincial GDP. Hence, we are making the hypothesis that productivity is constant within an industry in different parts of a province. Total GDP is estimated by summing all the industrial GDP values. Values are posted in units of 1997 millions of dollars; hence, inflation effects are eliminated.

Total Employment
Total employment is the sum of employment in all industries. Data are presented in units of thousands, and an annual percentage growth value is also provided.

Unemployment Rate
The unemployment rate is the ratio of the number of unemployed workers to the total labour force.

Personal Income
Personal income is the sum of all revenues (wages, dividends, self-employment, etc.) received in a year. Data are in millions of dollars and not corrected for inflation (current dollars).

Population
The population data include inhabitants of all municipalities that make up the CMA.

Total Housing Starts
Total housing starts represent the sum of multiple and single housing construction starts. Multiple housing includes any type of building that can lodge more than one household. Examples: apartment complex, condominium, duplex and triplex.

Retail Sales
Retail sales are quoted in units of millions of dollars and are not adjusted for inflation (current dollars).

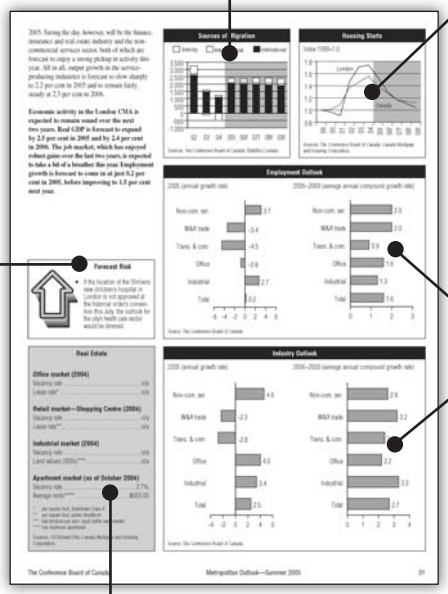
Consumer Price Index (CPI)
This index measures the cost of living for a typical urban family. It is composed of several goods priced after taxes. A benchmark year (1992, for example) is given the value 1.0. A value of 1.11 in 1999 is then interpreted as a growth of 11 per cent in the CPI between 1992 and 1999. Annual percentage growth rates are posted in italics below the CPI values.

Sources of Migration

Statistics Canada collects data for three types of population migration patterns: intercity, interprovincial and international. Intercity migration is defined as the flow of population moving out of or into the metropolitan area to or from other cities in the province. Interprovincial migration represents population movements between the metropolitan area and other Canadian provinces, excluding the province in which the metropolitan area lies. International migration is the population movement between other countries and the metropolitan area. The graph plots the net values for the three demographic variables. The values can be read by matching the borderline of the bar to the left scale.

Housing Starts

The graph demonstrates the growth in housing starts over a period of time. The base year (for example, 1996) is given the value 1.0. Hence, the following yearly data represent the growth value in comparison with 1996. For example, the value 1.2 means that housing starts have increased by 20 per cent since 1996. Two lines are shown in the graph, one for the metropolitan area and one for Canada.



Forecast Risk

To gauge the likelihood of the economic forecast unfolding, we indicate whether there is an upside or downside risk. As indicated by the arrow, the overall forecast is conditional on key assumptions that may boost or dampen the outlook.

Employment Outlook and Industry Outlook

Employment growth percentages for five specific sectors are shown for the current year and for an average yearly value over the next four years. The office sector is defined by these industries: finance, insurance and real estate (FIRE); commercial services; and public administration. The industrial sector includes the primary, manufacturing, construction and utilities industries.

Real Estate

Office Market

The vacancy rate is the percentage of units available to lease within the CMA. The average lease rate is quoted per square foot in the downtown Class A location.

Retail Market

The retail market consists of shopping centres, department stores, supermarkets, convenience stores and power centres. The lease rate for this sector is quoted per square foot, in a prime streetfront location.

Industrial Market

The industrial market consists of building units or assets devoted to production. Land values are quoted in units of thousands of dollars per acre in the most active land market of the CMA.

Apartment Market

The apartment market consists of building units devoted to residential dwellings. Average rents are quoted for a one-bedroom apartment.

Comparative Employment

Employment is disaggregated into five sectors: industrial; office; transportation and communication; wholesale and retail trade; and non-commercial services. This table shows the share of each employment component relative to the total.

Dominant Industries

Using the North American Industrial Classification System (NAICS), this table presents the most important industries for the CMA, ranked by employment. Industrial disaggregation is done at the four-digit level. The number of employees is quoted in units of thousands.

Large Employers

The Conference Board of Canada lists the CMA's major employers in the private and institutional sectors. These are not necessarily the largest employers, but taken together, they portray the metro job market.

Employment Market Variability

Fluctuations

Fluctuation linked to Canada is an indication of the degree of correlation between changes in employment in the CMA and changes in employment in Canada between 1987 and the current year.

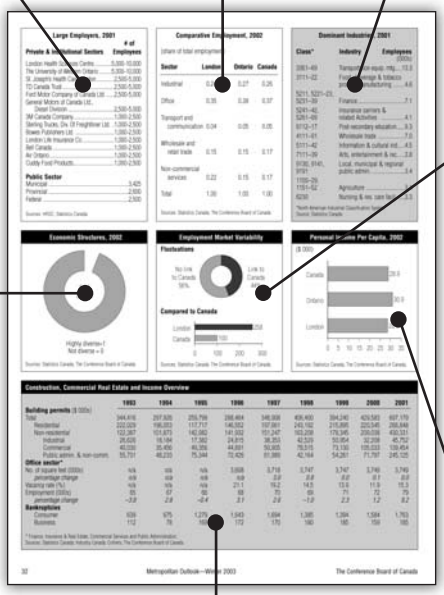
Fluctuation not linked to Canada is an indication of the degree of correlation between changes in employment in the CMA and changes in factors other than employment changes in Canada.

Compared to Canada

This bar chart represents the ratio of the standard deviation of total employment growth in the CMA to the standard deviation of total employment growth in Canada. The interpretation of this ratio is that the higher the number on the bar chart, the more volatile the labour market in the CMA relative to Canada.

Economic Structure

Canada is set as the benchmark for economic diversity. It is proposed that the Canadian economy is well diversified; hence, a comparison can be made between the CMAs and the Canadian economy. The value 1 is given to a metropolitan area that has the same industrial structure as Canada. A value of 0 means that the CMA has a totally different economic structure and thus implicitly lacks diversity.



Personal Income Per Capita

Personal income per capita is presented at the CMA, provincial and national levels. The information is presented in thousands of current (nominal) dollars.

Construction, Commercial Real Estate and Income Overview

Building Permits

Historical data are in units of thousands for the number of building permits issued and are presented on a disaggregated level. Total building permits can be split into two main categories: residential and non-residential. Furthermore, the non-residential sector is divided into three sub-components: industrial; commercial and public administration; and non-commercial.

Office Sector

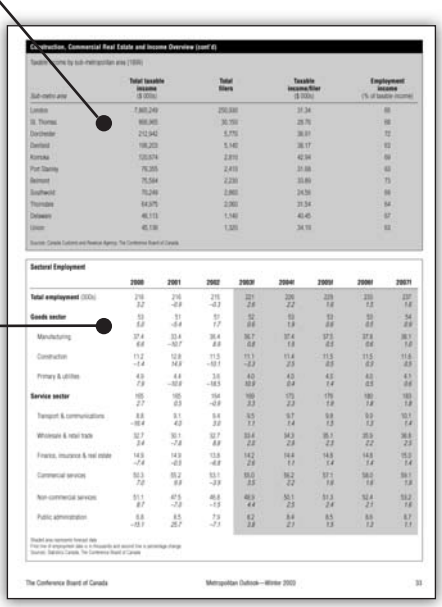
The total CMA office sector is quoted in units of thousands of square feet. This value evolves over time, and an annual growth percentage value is listed. The vacancy rate measures the amount of physically vacant space as a percentage of total inventory. Employment in thousands of units for the office sector is also quoted. The office sector is defined by these industries: finance, insurance and real estate (FIRE); commercial services; and public administration.

Bankruptcies

Business and consumer bankruptcy figures are available from Industry Canada.

Taxable Income by Sub-Metropolitan Area
The latest data available from Revenue Canada have been used to compile the total taxable income for sub-metropolitan areas, in units of thousands of dollars, The average taxable income per filer is calculated according to the number of people who file a tax report. Furthermore, the portion of taxable income that comes from employment income is highlighted.

Sectoral Employment
The most important industries for employment are listed, based on NAICS data. Industrial disaggregation is done at the four-digit level. The number of employees is quoted in units of thousands.



GLOSSARY OF ECONOMIC TERMS

Gross domestic product (GDP): A measure of the overall economic activity (value of goods and services produced) within an economy.

GDP at market prices: Represents the value of GDP as paid by final consumers; excludes subsidies but includes indirect taxes.

GDP at basic prices: Equivalent to GDP at market prices plus subsidies (product related) and minus indirect taxes (property and payroll but not sales taxes). It measures the value of producers' output. GDP at basic prices replaced GDP at factor cost, which was discontinued in January 2002.

Real* versus *nominal dollars: Real dollar economic measures such as GDP adjust for price changes and measure activity in a base year (e.g., $ 1997). Year-to-year changes in real or constant dollars reflect changes in quantities produced. Nominal dollar measures reflect quantities produced in prevailing prices (e.g., $000s). Year-to-year changes in nominal or current dollars reflect changes in both quantity and market prices.

Inflation: A sustained rise in the average level of all prices. The consumer price index is one measure of inflation and is used as a proxy for inflation at the urban level.

Labour force: The total number of persons employed in both civilian and military jobs, plus the number of persons who are unemployed.

Participation rate: The total labour force expressed as a percentage of the population aged 15 years and over.

Canadian Census Metropolitan Areas

St. John's
Conception Bay South T
Portugal Cove-St. Philip's T
Pouch Cove T
Flatrock T
Torbay T
Logy Bay-Middle Cove-Outer Cove T
Bauline T
Paradise T
St. John's C
Mount Pearl C
Petty Harbour-Maddox Cove T
Bay Bulls T
Witless Bay T

Halifax
Cole Harbour 30 R
Shubenacadie 13 R
Halifax RGM
Sheet Harbour 36 R

Saint John
Saint Martins PAR
St. Martins VL
Simonds PAR
Saint John C
Musquash PAR
Lepreau PAR
Petersville PAR
Upham PAR
Hampton PAR
Hampton T
Rothesay PAR
Westfield PAR
Kingston PAR
Grand Bay–Westfield T
Greenwich PAR
Rothesay T
Quispamsis T

Saguenay
Saint-Fulgence M
La Baie V
Laterrière V
Chicoutimi V
Tremblay CT
Saint-Honoré M
Shipshaw M
Jonquière V
Lac-Kénogami M
Larouche M

Québec
Beaumont M
Saint-François P
Sainte-Famille P
Saint-Jean P
Saint-Laurent-de-l'Île-d'Orléans M
Saint-Pierre-de-l'Île-d'Orléans M
Sainte-Pétronille VL
Château-Richer V
L'Ange-Gardien P
Boischatel M
Sainte-Catherine-de-la-Jacques-Cartier V
Fossambault-sur-le-Lac V
Lac-Saint-Joseph V
Shannon M
Saint-Gabriel-de-Valcartier M
Lac-Delage V
Stoneham-et-Tewkesbury CU
Lac-Beauport M
Sainte-Brigitte-de-Laval M
Beauport V
Vanier V
Notre-Dame-des-Anges P
Sillery V
Québec V
Charlesbourg V
Saint-Émile V
Lac-Saint-Charles V
Loretteville V
Val-Bélair V
L'Ancienne-Lorette V
Sainte-Foy V
Cap-Rouge V
Saint-Augustin-de-Desmaures M
Wendake R
Pintendre M
Saint-Joseph-de-la-Pointe-de-Lévy P
Lévis V
Saint-Lambert-de-Lauzon P
Saint-Étienne-de-Lauzon M
Sainte-Hélène-de-Breakeyville P
Saint-Jean-Chrysostome V
Saint-Romuald V
Charny V
Saint-Rédempteur V
Saint-Nicolas V

Sherbrooke
Ascot Corner M
Stoke M
Saint-Denis-de-Brompton P
Waterville V
Lennoxville V
Ascot M
Fleurimont V
Bromptonville V
Sherbrooke V
Rock Forest V
Deauville M
Saint-Élie-d'Orford M
Compton M
North Hatley VL
Hatley CT

Trois-Rivières
Champlain M
Saint-Maurice P
Sainte-Marthe-du-Cap V
Cap-de-la-Madeleine V
Saint-Louis-de-France V
Trois-Rivières V
Trois-Rivières-Ouest V
Pointe-du-Lac M
Bécancour V
Wôlinak 11 R

Montréal
Lavaltrie VL
Saint-Antoine-de-Lavaltrie P
Richelieu V
Saint-Mathias-sur-Richelieu M
Chambly V
Carignan V
Saint-Bruno-de-Montarville V
Saint-Basile-le-Grand V
McMasterville M
Otterburn Park V
Mont-Saint-Hilaire V
Beloeil V
Saint-Mathieu-de-Beloeil M
Brossard V
Saint-Lambert V
Greenfield Park V
Saint-Hubert V
LeMoyne V
Longueuil V
Boucherville V
Sainte-Julie V
Saint-Amable M
Varennes V
Charlemagne V
Le Gardeur V
Repentigny V
Saint-Sulpice P
L'Assomption V
Lachenaie V
Terrebonne V
Mascouche V
La Plaine V
Laval V
Montréal-Est V
Anjou V
Saint-Léonard V
Montréal-Nord V
Montréal V
Westmount V
Verdun V
LaSalle V
Montréal-Ouest V
Côte-Saint-Luc C
Lachine V
Hampstead V
Outremont V
Mont-Royal V
Saint-Laurent V
Dorval C
L'Île-Dorval V
Pointe-Claire V
Kirkland V
Beaconsfield V
Baie-d'Urfé V
Sainte-Anne-de-Bellevue V
Senneville VL
Pierrefonds V
Sainte-Geneviève V
Dollard-des-Ormeaux V
Roxboro V
L'Île-Bizard V
Saint-Mathieu M
Saint-Philippe M
La Prairie V
Candiac V
Delson V
Sainte-Catherine V
Saint-Constant V
Saint-Isidore P
Mercier V
Châteauguay V
Léry V
Kahnawake 14 R
Maple Grove V

Canadian Census Metropolitan Areas

Beauharnois V
Melocheville VL
Les Cèdres M
Pointe-des-Cascades VL
L'Île-Perrot V
Notre-Dame-de-l'Île-Perrot M
Pincourt V
Terrasse-Vaudreuil M
Vaudreuil-Dorion V
Vaudreuil-sur-le-Lac VL
L'Île-Cadieux V
Hudson V
Saint-Lazare P
Saint-Eustache V
Deux-Montagnes V
Sainte-Marthe-sur-le-Lac V
Pointe-Calumet M
Saint-Joseph-du-Lac M
Oka M
Saint-Placide M
Kanesatake R
Boisbriand V
Sainte-Thérèse V
Blainville V
Rosemère V
Lorraine V
Bois-des-Filion V
Sainte-Anne-des-Plaines V
Mirabel V
Saint-Colomban P
Bellefeuille V
Saint-Jérôme V
Saint-Antoine V
Lafontaine V
Gore CT

Ottawa–Gatineau
Buckingham V
Masson-Angers V
Gatineau V
Hull V
Aylmer V
Val-des-Monts M
Cantley M
Chelsea M
Pontiac M
La Pêche M
Clarence-Rockland C
Russell TP
Ottawa C

Kingston
Frontenac Islands TP
Kingston C
South Frontenac TP
Loyalist TP

Oshawa
Whitby T
Oshawa C
Clarington T

Toronto
Pickering C
Ajax T
Uxbridge TP
Vaughan C
Markham T
Richmond Hill T
Whitchurch-Stouffville T
Aurora T
Newmarket T
King TP
East Gwillimbury T
Georgina T
Chippewas of Georgina
Island First Nation R
Toronto C
Mississauga C
Brampton C
Caledon T
Mono T
Orangeville T
Oakville T
Milton T
Halton Hills T
New Tecumseth T
Bradford West Gwillimbury T

Hamilton
Burlington C
Hamilton C
Grimsby T

St. Catharines–Niagara
Fort Erie T
Port Colborne C
Wainfleet TP
Pelham T
Welland C
Thorold C
Niagara Falls C
Niagara-on-the-Lake T
St. Catharines C
Lincoln T

Kitchener
North Dumfries TP
Cambridge C
Kitchener C
Waterloo C
Woolwich TP

London
Central Elgin TP
St. Thomas C
Southwold TP
Strathroy-Caradoc TP
Thames Centre TP
Middlesex Centre TP
London C

Windsor
Amherstburg T
LaSalle T
Windsor C
Tecumseh T
Lakeshore T

Greater Sudbury
Whitefish Lake 6 R
Greater Sudbury C
Wahnapitei 11 R

Thunder Bay
Neebing TP
Fort William 52 R
Thunder Bay C
Oliver Paipoonge TP
Gillies TP
O'Connor TP
Conmee TP
Shuniah TP

Winnipeg
Taché RM
Ritchot RM
St. François Xavier RM
Winnipeg C
Headingley RM
Autumnfield RM
East St. Paul RM
West St. Paul RM
St. Clements RM
Brokenhead 4 R
Rosser RM

Regina
Pense No. 160 RM
Belle Plaine VL
Pense VL
Sherwood No. 159 RM
Regina C
Grand Coulee VL
Edenwold No. 158 RM
White City T
Pilot Butte T
Balgonie T
Edenwold VL
Lumsden No. 189 RM
Disley VL
Buena Vista VL
Lumsden T
Lumsden Beach RV
Regina Beach T

Saskatoon
Thode RV
Dundurn No. 314 RM
Dundurn T
Shields RV
Corman Park No. 344 RM
Saskatoon C
Langham T
Warman T
Blucher No. 343 RM
Martensville T
Bradwell VL
Allan T
Dalmeny T
Elstow VL
Osler T
Colonsay No. 342 RM
Clavet VL
Meacham VL
Colonsay T
White Cap 94 R
Vanscoy No. 345 RM
Delisle T
Vanscoy VL
Asquith T

Calgary
Rocky View No. 44 MD
Calgary C
Chestermere T

Canadian Census Metropolitan Areas

Cochrane T
Airdrie C
Irricana VL
Beiseker VL
Crossfield T
Tsuu T'ina Nation 145 R

Edmonton
Bruderheim T
Leduc County CM
Beaumont T
New Sarepta VL
Leduc C
Devon T
Calmar T
Sundance Beach SV
Thorsby VL
Itaska Beach SV
Golden Days SV
Warburg VL
Parkland County CM
Seba Beach SV
Betula Beach SV
Point Alison SV
Lakeview SV
Kapasiwin SV
Wabamun VL
Autumn Lake VL
Stony Plain T
Spruce Grove C
Strathcona County SM
Fort Saskatchewan C
Sturgeon County MD
Edmonton C
St. Albert C
Gibbons T
Redwater T
Bon Accord T
Morinville T
Legal T
Stony Plain 135 R
Alexander 134 R
Wabamun 133A R

Abbotsford
Abbotsford C
Mission DM
Fraser Valley H RDA
Upper Sumas 6 R
Matsqui Main 2 R

Vancouver
Langley DM
Langley C
Surrey C
White Rock C
Delta DM
Richmond C
Greater Vancouver A RDA
Vancouver C
Burnaby C
New Westminster C
Coquitlam C
Belcarra VL
Anmore VL
Port Coquitlam C
Port Moody C
North Vancouver DM
North Vancouver C
West Vancouver DM
Bowen Island IM
Lions Bay VL
Pitt Meadows DM
Maple Ridge DM
Semiahmoo R
Tsawwassen R
Musqueam 2 R
Coquitlam 2 R
Coquitlam 1 R
Burrard Inlet 3 R
Mission 1 R
Capilano 5 R
Barnston Island 3 R
Musqueam 4 R
Seymour Creek 2 R
Katzie 2 R
McMillan Island 6 R
Matsqui 4 R
Katzie 1 R
Langley 5 R
Whonnock 1 R

Victoria
North Saanich DM
Sidney T
Central Saanich DM
Saanich DM
Oak Bay DM
Victoria C
Esquimalt DM
Colwood C
Metchosin DM
Langford DM
View Royal T
Highlands DM
Sooke DM
Capital H RDA
Cole Bay 3 R
Union Bay 4 R
East Saanich 2 R
South Saanich 1 R
Becher Bay 1 R
Esquimalt R 10000
New Songhees 1A R
T'Sou-ke 1 R
T'Sou-ke 2 R

Abbreviations:

C = City
CM = County (Municipality)
CT = Canton (Municipalité de)
CU = Cantons unis (Municipalité de)
DM = District Municipality
IM = Island Municipality
M = Municipalité
MD = Municipal District
P = Paroisse (Municipalité de)
PAR = Parish
R = Indian Reserve
RDA = Regional District Electoral Area
RGM = Regional Municipality
RM = Rural Municipality
RV = Resort Village
SV = Summer Village
T = Town
TP = Township
V = Ville
VL = Village

Note: The 2001 census metropolitan areas reflect the agglomeration of several individual municipalities into one jurisdiction. For example, Halifax CMA now encompasses Halifax Regional Municipality, Cole Harbour, Shubenacadie, and Sheet Harbour. The Halifax Regional Municipality includes Bedford, Dartmouth, and Halifax, which were listed separately in the 1996 definition of the Halifax CMA.

In 2001, Statistics Canada increased the number of CMAs to 27. Abbotsford and Kingston were added.

Cross-City Comparison

Real GDP (per cent) 2006		Real GDP (per cent) 2007		Real GDP (per cent) 2008f–2011f	
Calgary	7.3	Calgary	3.9	Toronto	4.1
Edmonton	6.6	Edmonton	3.6	Calgary	3.8
Victoria	3.9	Vancouver	3.1	Edmonton	3.5
Abbotsford	3.9	St. Catharines–Niagara	3.1	Vancouver	3.4
Vancouver	3.9	Abbotsford	3.0	Ottawa–Gatineau	3.0
Saskatoon	3.3	Toronto	2.9	Hamilton	2.9
Québec City	3.2	Winnipeg	2.9	Abbotsford	2.9
Halifax	2.9	Saskatoon	2.9	Sherbrooke	2.9
Winnipeg	2.8	Halifax	2.8	London	2.8
Ottawa–Gatineau	2.6	Québec City	2.5	Montréal	2.8
Toronto	2.3	Ottawa–Gatineau	2.5	Winnipeg	2.6
Regina	2.1	Montréal	2.5	Québec City	2.5
Trois-Rivières	1.8	London	2.4	Halifax	2.5
Montréal	1.5	Regina	2.4	Saskatoon	2.5
London	1.5	Hamilton	2.3	Victoria	2.4
Sudbury	1.3	Sherbrooke	2.2	Trois-Rivières	2.3
Sherbrooke	1.2	Victoria	2.1	St. Catharines–Niagara	2.3
Hamilton	1.1	Thunder Bay	2.0	Regina	2.2
Thunder Bay	0.5	Sudbury	1.5	Sudbury	2.1
St. Catharines–Niagara	0.4	Trois-Rivières	1.5	Thunder Bay	1.8

CANADA

- Real household spending is being bolstered by outstanding gains in after-tax income.

- Consumer spending growth will weaken south of the border as U.S. real estate prices slump.

Overview The impact of the housing price correction south of the border and its effect on the debt-laden American consumer will limit U.S. economic growth to 2.2 per cent in 2007. Inescapably, Canada will feel the repercussions of weaker U.S. home building and consumer spending, particularly in those sectors supplying the residential construction industry. In addition, softer U.S. demand will hurt already strained exporters and manufacturers as well as domestic sectors catering to American tourists. Fortunately, Canada's domestic economy has enough momentum to perform well despite the hiccup in U.S. growth. All in all, following an estimated gain of 2.7 per cent in 2006, real gross domestic product (GDP) growth in Canada is forecast to come in at 2.9 per cent in 2007 and at 3.3 per cent in 2008.

Widespread Strength in Domestic Demand Canadian households are enjoying the combined effects of exceptional gains in after-tax income and the steep rise in purchasing power due to the strength of the loonie. Moreover, while housing prices may be softening in the United States, they are still rising in Canada, adding to the wealth effect. Profits have also continued to rise, resulting in unabated growth in business investment spending, while the federal and provincial governments, perhaps surprised by better-than-expected revenues, are likely to keep spending growth strong. Consumer spending, business investment and government spending together spurred domestic demand throughout 2006 despite a sharp reduction in residential construction starting in the second quarter of the year.

All signs continue to point to exceptional growth in household income into 2007. Federal and provincial income tax cuts and transfers to persons have been generous, adding nearly $11 billion to household disposable income in the 2006 calendar year. About $8.7 billion of this amount is coming from federal measures that will remain in place. Adding to the fiscal windfall, labour market conditions are favourable for good growth in income. Job gains started the year 2006 on a very strong note, and while it is true that employment has been stagnant over the past few months, the weakness is more likely due to a lack of labour supply, or at least labour with the right skills and in the right regions, than to a slowdown in demand. Indeed, tight labour markets throughout the country are driving healthy growth in real wages, especially in Alberta, where unemployment rates are at rock-bottom levels. The overall strength in real after-tax income bolstered real consumer spending by an estimated 4 per cent in 2006, despite a slightly softer housing market. Real consumer spending growth is expected to ease to a more sustainable pace, posting gains of 3.4 per cent in 2007 and 3.2 per cent in 2008.

While eroding competitiveness, a strong currency also has the effect of lowering the price of machinery and equipment, much of which is imported, providing a strong incentive to retool or purchase efficiency-enhancing machines. Corporate balance sheets remain in remarkable shape despite cost and wage pressures, and this will spur further business investment spending over the medium term. Overall, private sector investment will continue to shore up overall economic growth, especially until 2008, when construction activity on oil sands projects is expected to peak.

Awaiting the Trade Sector Rebound As has been the trend since 2003, it was the trade sector—indeed an outstanding jump in imports—that held back growth in 2006. And while imports have been bolstered by the strength of the Canadian dollar, the currency's strength has also served to further erode export competitiveness. Softer consumer spending south of the border will hinder Canada's export potential in 2007 even with a softening currency. Projected export growth for 2007 has been revised down substantially since the summer *Metropolitan Outlook*, and the sectors hit will be most damaging for Central Canada. Therefore, while Canada's overall economy is expected to sail through the U.S. slowdown relatively unscathed, Ontario and Quebec are likely to suffer more damaging consequences. Consequently, the recent trend of diverging regional performance is expected to continue, at least through 2007.

Challenges in the trade sector are limiting growth in the country's real GDP; after increasing by 2.7 per cent in 2006, real GDP will climb by 2.9 per cent in 2007. Thankfully, strong increases in after-tax income will continue to support growth in domestic demand.

Forecast Risks

- While the current forecast incorporates our thoughts on the most probable effect on households of a correction in U.S. housing prices, it is possible that consumers will retrench more than has been assumed in the baseline forecast.

Real GDP Growth

2006	2007	2008–2011	2002–2011
2.7%	2.9%	3.1%	2.9%

Credit Quality

AAA

Standard & Poor's

Economic Indicators	2004	2005	2006	2007f	2008f	2009f	2010f	2001f
Real GDP at market prices (1997 $ millions)	1,124,688	1,157,705	1,188,989	1,223,459	1,263,251	1,303,240	1,343,307	1,384,552
percentage change	*3.3*	*2.9*	*2.7*	*2.9*	*3.3*	*3.2*	*3.1*	*3.1*
Total employment (000s)	15,949	16,169	16,461	16,718	16,978	17,233	17,472	17,708
percentage change	*1.8*	*1.4*	*1.8*	*1.6*	*1.6*	*1.5*	*1.4*	*1.3*
Unemployment rate	7.2	6.8	6.5	6.6	6.4	6.3	6.2	6.0
Personal income ($ millions)	979,012	1,027,733	1,084,892	1,130,215	1,181,297	1,234,224	1,289,094	1,346,566
Population (000s)	31,932	32,232	32,537	32,835	33,141	33,455	33,779	34,113
percentage change	*1.0*	*0.9*	*0.9*	*0.9*	*0.9*	*0.9*	*1.0*	*1.0*
Single-family housing starts (000s)	129.2	120.5	114.5	109.1	106.6	104.5	101.9	99.5
Multi-family housing starts (000s)	104.3	105.0	111.1	93.5	88.1	87.0	87.3	88.8
Retail sales ($ millions)	346,721	368,612	393,264	415,610	437,978	461,812	486,113	511,431
percentage change	*4.7*	*6.3*	*6.7*	*5.7*	*5.4*	*5.4*	*5.3*	*5.2*
CPI (1992=1.000)	1.246	1.273	1.297	1.315	1.342	1.369	1.397	1.424
percentage change	*1.8*	*2.2*	*1.9*	*1.4*	*2.0*	*2.0*	*2.0*	*2.0*

ONTARIO

- Investment expenditures are forecast to remain strong over the medium term.
- Trade continues to be a drag on economic growth.

Manufacturing Hit by Mild Recession A recession is defined as two consecutive quarters of negative growth. With large declines in auto and auto parts production, manufacturing in Ontario contracted in both the first and second quarters of 2006, resulting in a recession. The contraction in manufacturing output was clearly not a good sign for exporters. For the year as a whole, manufacturing output contracted by an estimated 0.8 per cent, limiting growth in real exports to a paltry 1.2 per cent. But exporters will fare better in 2007 when manufacturing makes a modest rebound, with strength emanating from the chemical, electrical equipment, machinery and equipment, and refined petroleum and coal products industries. Manufacturing output is expected to grow by 2.4 per cent in 2007, boosting export growth to 2.6 per cent.

Drag From Trade Continues While the export side of the economy continues to struggle, imports will continue to surge, thanks in part to the strong Canadian dollar. Strong demand for machinery and equipment and for consumer goods helped propel import growth to 4.8 per cent in 2006, with a further 4 per cent gain forecast in 2007. Given the strong growth in imports and sluggish performance from exporters, net exports will continue to be a drag on bottom-line growth. The trade sector stripped an estimated 2 percentage points from GDP growth in 2006 and is expected to take away another 0.6 percentage points in 2007.

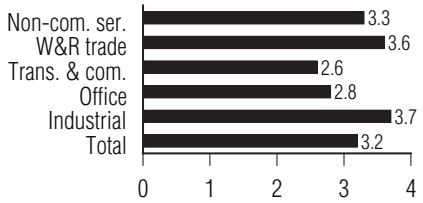
Investment Growth Leads the Way Investment expenditures continue to outpace economic growth in Ontario, with real gross fixed capital formation expanding by an impressive 4.9 per cent in 2006 and 4.2 per cent in 2007. The high value of the Canadian dollar continues to encourage companies to invest in machinery and equipment, with gains in this category reaching a staggering 9.5 per cent in 2006 and 9.4 per cent in 2007. Investment growth has also been strong in the non-residential sector, thanks in particular to low financing rates and limited spare capacity in the commercial and industrial markets. Non-residential investment growth, which reached an estimated 4.7 per cent in 2006, is forecast to ease to 2.3 per cent in 2007. Moreover, government investment is expected to remain strong over the medium term, boosted by upgrades to energy and transportation infrastructure. On a negative note, the residential sector continues to weaken. Housing starts fell by an estimated 3.9 per cent in 2006 and are forecast to decrease by a further 1.5 per cent in 2007.

Ontario Consumers Remain Upbeat Despite the troubles in the manufacturing sector, Ontario consumers remain upbeat. This, along with healthy employment growth outside the manufacturing sector and solid disposable income gains, will buoy consumer spending. Specifically, consumer spending, which increased by an estimated 3.1 per cent in 2006, is expected to post a solid gain of 3.2 per cent in 2007.

The economic outlook for Ontario will remain tempered over the near term. Real gross domestic product (GDP) advanced by an estimated 1.8 per cent in 2006 and is forecast to grow by 2.5 per cent in 2007, a significant downward revision from the 2.9 per cent forecast in the last *Metropolitan Outlook*.

Industry Outlook, 2007–2011

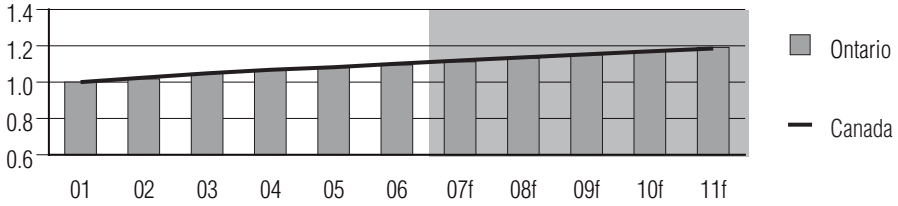
(average annual compound growth rate)



Forecast Risk

- Failure by the manufacturing industry to make a speedy recovery would spell bad news for the trade sector.

Employment in Perspective (2000=1.0)



Real GDP Growth

2006	2007	2008–2011	2002–2011
1.8%	2.5%	3.4%	2.8%

Credit Quality

AA

Standard & Poor's

Economic Indicators	2004	2005	2006	2007f	2008f	2009f	2010f	2011f
Real GDP at basic prices (1997 $ millions)	434,383	447,338	455,582	466,867	482,250	498,524	515,509	532,650
percentage change	*3.0*	*3.0*	*1.8*	*2.5*	*3.3*	*3.4*	*3.4*	*3.3*
Total employment (000s)	6,317	6,397	6,488	6,589	6,702	6,815	6,936	7,059
percentage change	*1.7*	*1.3*	*1.4*	*1.6*	*1.7*	*1.7*	*1.8*	*1.8*
Unemployment rate	6.8	6.6	6.5	6.7	6.7	6.7	6.6	6.4
Personal income ($ millions)	400,358	419,490	438,717	457,906	478,945	500,951	524,329	548,868
Population (000s)	12,394	12,537	12,659	12,782	12,924	13,074	13,234	13,401
percentage change	*1.3*	*1.2*	*1.0*	*1.0*	*1.1*	*1.2*	*1.2*	*1.3*
Single-family housing starts (000s)	48.9	41.7	36.8	34.9	36.3	37.2	37.7	37.9
Multi-family housing starts (000s)	36.2	37.1	39.0	39.7	38.8	39.3	40.2	41.5
Retail sales ($ millions)	129,086	135,416	141,308	148,900	157,086	165,866	174,957	184,478
percentage change	*3.2*	*4.9*	*4.4*	*5.4*	*5.5*	*5.6*	*5.5*	*5.4*
CPI (1992=1.000)	1.256	1.284	1.309	1.327	1.358	1.389	1.419	1.449
percentage change	*1.9*	*2.2*	*1.9*	*1.4*	*2.3*	*2.4*	*2.1*	*2.1*

TORONTO

- The Toronto CMA regularly attracts over 55,000 net migrants annually, supporting growth in domestic demand.
- Toronto is expected to boast one of the fastest-growing metropolitan economies in the country from 2008 to 2011.

Overview The impact of the strong Canadian dollar on industries sensitive to foreign trade, especially manufacturing and tourism, has dampened overall economic growth in the Toronto census metropolitan area (CMA). Specifically, real gross domestic product (GDP) increased on average by 2.9 per cent per year from 2003 to 2005—well short of Toronto's economic potential. Unfortunately, Toronto's economy continued to struggle in 2006 and is forecast to improve only modestly in 2007. In fact, the CMA will have to wait until 2008 before the economy gets back on a fast growth track.

Manufacturers Shedding Jobs Toronto's manufacturing sector has fought valiantly against the rapid rise in the Canadian dollar, with output increasing on average by 2.2 per cent annually from 2003 to 2005. But the fight was not without casualties, as more than 25,000 manufacturing jobs were cut over this period. The sector took even more severe body blows in 2006. In fact, output contracted by an estimated 1.2 per cent and manufacturers shed some 36,000 more jobs in the year alone.

Fortunately, the manufacturing sector is expected to improve modestly in 2007. The sector received a lift in the fourth quarter of 2006 from a boost in production at Ford's Oakville assembly complex, which began producing two new crossover utility vehicles—the Ford Edge and Lincoln MKX. At the same time, Bombardier is ramping up production of Q-Series turboprops at its Downsview plant in north Toronto. Accordingly, manufacturing output is forecast to expand by 2.4 per cent in 2007. Nevertheless, the increase in output is expected to come solely from productivity gains, as overall manufacturing employment is expected to contract once again in 2007. In fact, the manufacturing employment picture is not expected to brighten until 2008, when job growth finally moves into positive territory.

Services Sector Growth Slowing Toronto's transportation and tourism industries are also feeling the pinch from the high-flying loonie, along with high gas prices and increased hassles at the border and at airports. Indeed, transportation, storage and communications output increased by a modest 2 per cent in 2006. At the same time, output in the commercial services sector, which includes tourist-oriented industries such as accommodation and food, eked out 1.4 per cent growth. But solid growth in domestic demand helped offset the struggles in the transportation and tourism sectors. In fact, Toronto's consumers remain buoyant, thanks to healthy job gains outside the manufacturing sector, solid disposable income growth, low borrowing costs and brisk population growth. Still, overall output growth in the services-producing industries slowed somewhat from 3.9 per cent in 2005 to 3.3 per cent in 2006.

Fortunately, the transportation and tourism industries are expected to enjoy somewhat better days in 2007, thanks to increases in the number of domestic and overseas travellers, which will help offset continued declines in the number of U.S. tourists. The transportation industry will also be aided by improving conditions in the manufacturing sector. Indeed, transportation, storage and communications output is forecast to increase by 2.4 per cent in 2007, while commercial services output growth is expected to accelerate to 3.3 per cent. But domestic demand is expected to cool slightly, partly because of slower disposable income growth and rising interest rates. All in all, services sector output is forecast to slow further to 3.1 per cent in 2007.

Construction Activity Remains Healthy The construction industry was the beneficiary of a housing boom that ran from the late 1990s to 2003. But now the housing sector is gliding towards a soft landing. After reaching a peak of 45,500 units in 2003, housing starts have been trending down

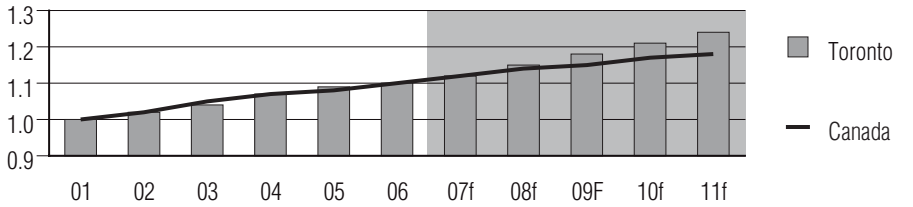
Real GDP Growth and Ranking

2006	2007	2008–2011	2002–2011
2.3%	2.9%	4.1%	3.4%
#11	#6	#1	#5

Out of 20 CMAs

Credit Quality	Cost of Living
AA	*101%*
City of Toronto Standard & Poor's	Canada=100%

Employment in Perspective (2000=1.0)



Economic Indicators	2004	2005	2006	2007f	2008f	2009f	2010f	2001f
Real GDP at basic prices (1997 $ millions)	192,205	198,683	203,217	209,191	217,565	226,461	235,679	245,281
percentage change	*3.4*	*3.4*	*2.3*	*2.9*	*4.0*	*4.1*	*4.1*	*4.1*
Total employment (000s)	2,707	2,763	2,799	2,845	2,922	2,997	3,074	3,155
percentage change	*2.2*	*2.1*	*1.3*	*1.6*	*2.7*	*2.6*	*2.6*	*2.6*
Unemployment rate	7.5	7.0	6.6	7.0	7.0	6.9	6.8	6.7
Personal income ($ millions)	176,896	185,959	196,030	205,026	216,319	228,043	240,501	253,844
Population (000s)	5,214	5,304	5,397	5,498	5,603	5,712	5,826	5,944
percentage change	*1.9*	*1.7*	*1.7*	*1.9*	*1.9*	*1.9*	*2.0*	*2.0*
Total housing starts (000s)	42.1	41.6	38.1	39.0	39.8	41.4	43.0	44.9
Retail sales ($ millions)	51,408	53,770	55,393	58,577	62,214	66,198	70,355	74,738
percentage change	*2.9*	*4.6*	*3.0*	*5.7*	*6.2*	*6.4*	*6.3*	*6.2*
CPI *(percentage change)*	*1.7*	*1.8*	*1.8*	*1.3*	*2.3*	*2.4*	*2.1*	*2.1*

ever since. They fell by an estimated 8.5 per cent to 38,100 units in 2006, the first time starts failed to reach the 40,000-unit mark since 2000. New home building is expected to remain fairly steady in 2007, with 39,000 starts forecast. Despite the slowdown in residential investment in recent years, overall construction activity has remained healthy, thanks to solid gains in the non-residential sector. Investment has been particularly strong in the downtown office sector. In fact, three new towers will join Toronto's skyline in 2009: the 1.3 million-square-foot RBC Centre in the entertainment district; the 1.1 million-square-foot Bay-Adelaide Centre in the financial district; and the 780,000-square-foot TELUS tower next to the Air Canada Centre. All in all, construction output is expected to expand by 3 per cent in 2007, following an estimated 4.1 per cent gain in 2006.

Real GDP in the Toronto CMA, which increased by a disappointing 2.3 per cent in 2006, is forecast to expand by 2.9 per cent in 2007. The modest improvement in economic activity will allow job growth to accelerate slightly from 1.3 per cent in 2006 to 1.6 per cent in 2007. Fortunately, better economic growth results are in the cards over the medium term.

Forecast Risk

- The U.S. economy could slow more than expected, putting further strain on Toronto's export-oriented industries.

Real Estate

Office market (2005)
Vacancy rate.....9.8%
Lease rate* $21.00

Retail market—shopping centre (2005)
Vacancy rate.....2.4%
Lease rate**.....$195.00

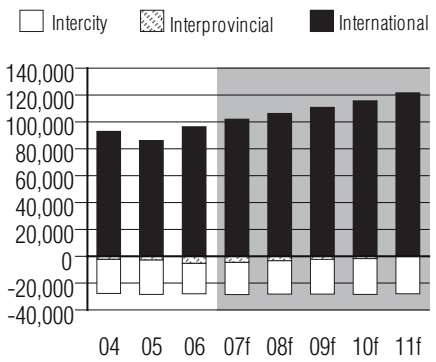
Industrial market (2005)
Vacancy rate.....5.5%
Land values (000s)***.....$575.00

Apartment market (as of October 2005)
Vacancy rate.....3.7%
Average rents**** $888.00

* per square foot, downtown Class A
** per square foot, prime streetfront
*** full services per acre, most active land market
**** one-bedroom apartment

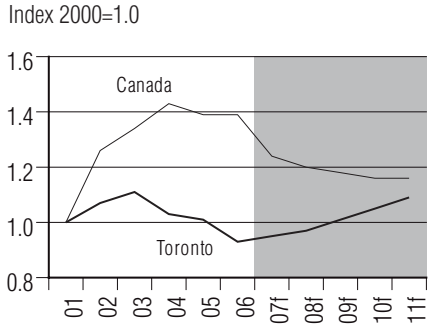
Sources: Colliers; Canada Mortgage and Housing Corporation.

Sources of Migration



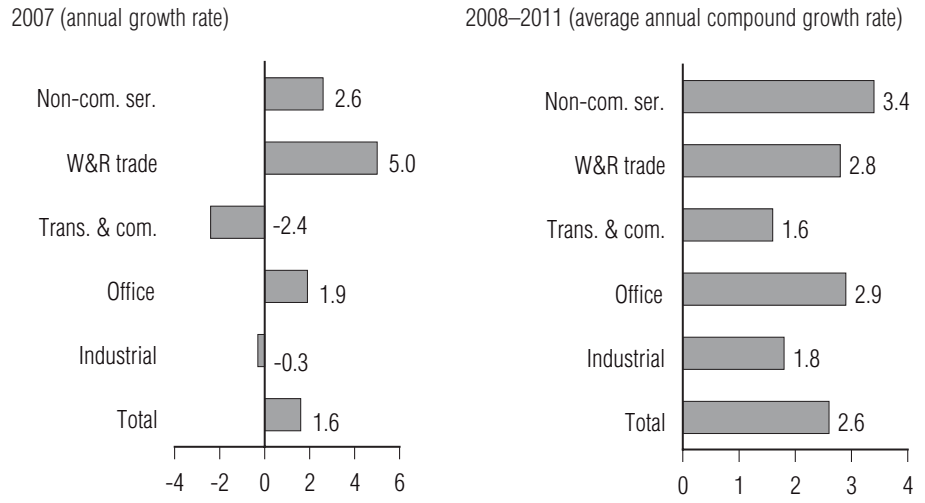
Sources: The Conference Board of Canada; Statistics Canada.

Housing Starts



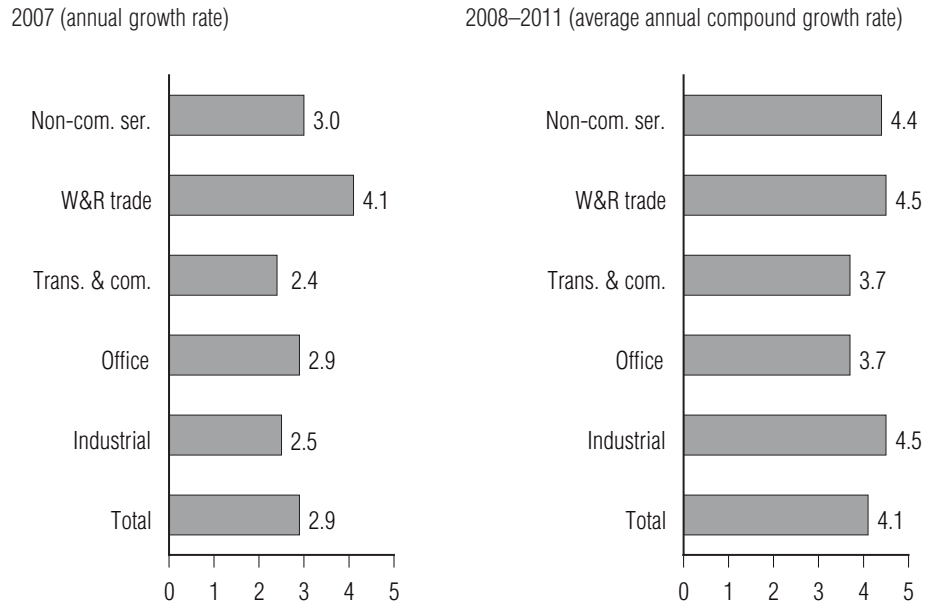
Sources: The Conference Board of Canada; Canada Mortgage and Housing Corporation.

Employment Outlook



Source: The Conference Board of Canada.

Industry Outlook



Source: The Conference Board of Canada.

Large Employers, 2005

Private & Institutional Sectors	# of Employees
Air Canada Inc.	10,000+
The Bank of Nova Scotia	10,000+
Canada Post Corp.	10,000+
Canadian Imperial Bank of Commerce	10,000+
The Great Atlantic & Pacific Company of Canada Ltd.	10,000+
Magna International Inc.	10,000+
Royal Bank of Canada	10,000+
TD Bank Financial Group	10,000+
Toronto Transit Commision	10,000+
University of Toronto	10,000+
Bank of Montreal	5,000–10,000
Bell Canada	5,000–10,000
Ford Motor Company of Canada Ltd.	5,000–10,000
IBM Canada Ltd.	5,000–10,000
Public Administration Sector	
Municipal	41,075
Provincial	27,875
Federal	21,800

Sources: The Toronto Board of Trade—Contact Toronto; Statistics Canada.

Comparative Employment, 2005

(share of total employment)

Sector	Toronto	Ontario	Canada
Industrial	0.24	0.26	0.25
Office	0.38	0.35	0.34
Transport and communication	0.08	0.07	0.07
Wholesale and retail trade	0.16	0.16	0.16
Non-commercial services	0.14	0.16	0.18
Total	1.00	1.00	1.00

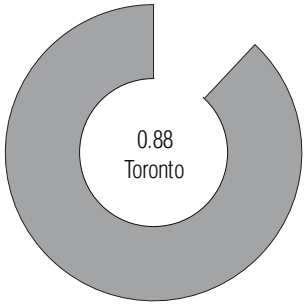
Sources: The Conference Board of Canada; Statistics Canada.

Dominant Industries, 2005

Class*	Industry	Employees (000s)
5211, 5221–23, 5231–39	Finance	155.7
4111–91	Wholesale trade	129.2
7221–24	Food & beverage services	119.2
4811–4922	Transportation	119.1
6111	Primary & sec. schools	100.6
5111–42	Info. & cultural ind.	96.9
5511, 5611–12, 5615–17, 5619 5621–29	Other management & administrative services	84.8
3361–69	Transportation equip. mfg.	73.9
6211–19	Ambulatory health care serv.	73.5
5415	Computer sys. design serv.	71.3

*North American Industrial Classification System
Source: Statistics Canada.

Economic Structure, 2005

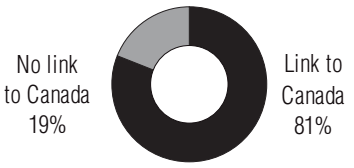


Highly diverse=1
Not diverse=0

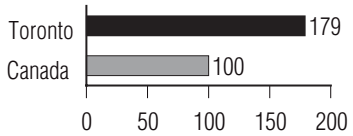
Sources: The Conference Board of Canada; Statistics Canada.

Employment Market Variability

Fluctuations



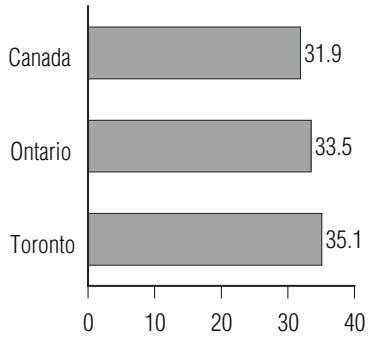
Compared to Canada



Sources: The Conference Board of Canada; Statistics Canada.

Personal Income Per Capita, 2005

($ 000s)



Sources: The Conference Board of Canada; Statistics Canada.

Construction, Commercial Real Estate and Income Overview

	1997	1998	1999	2000	2001	2002	2003	2004	2005
Building permits ($ 000s)									
Total	6,466,640	7,137,754	8,815,614	8,539,456	9,534,905	10,525,171	11,642,394	12,148,850	11,377,183
Residential	4,122,658	4,068,678	5,151,246	5,291,578	5,999,354	7,256,279	7,417,823	7,650,693	7,494,559
Non-residential	2,343,982	3,069,076	3,664,368	3,247,878	3,535,551	3,268,892	4,224,571	4,498,157	3,882,624
Industrial	641,859	798,501	683,822	801,588	663,585	561,471	963,349	911,916	677,406
Commercial	1,269,466	1,738,706	2,374,166	1,853,542	1,805,487	1,501,855	1,883,140	2,198,456	2,153,946
Public admin. & non-comm.	432,657	531,869	606,380	592,748	1,066,479	1,205,566	1,378,082	1,387,785	1,051,272
Office sector*									
No. of square feet (000s)	65,994	66,119	65,615	68,290	71,361	73,489	74,165	73,495	75,739
percentage change	*–1.7*	*0.2*	*–0.8*	*4.1*	*4.5*	*3.0*	*0.9*	*–0.9*	*3.1*
Vacancy rate (%)	11.9	10.5	9.9	6.0	9.6	12.1	14.2	13.5	9.6
Employment (000s)	858	874	899	930	944	987	1025	1026	1049
percentage change	*5.4*	*1.9*	*2.9*	*3.4*	*1.6*	*4.5*	*3.9*	*0.0*	*2.3*
Bankruptcies									
Consumer	11,909	9,528	7,865	7,677	8,477	9,210	10,321	10,691	10,983
Business	1,246	1,208	1,033	1,047	1,307	1,112	1,106	1,016	1,089

*Finance, insurance & real estate, commercial services and public administration.
Sources: The Conference Board of Canada; Statistics Canada; Industry Canada; CB Richard Ellis.

Construction, Commercial Real Estate and Income Overview (cont'd)

Taxable income by sub-metropolitan area (2002)

Sub-metro area	Total taxable income ($ 000s)	Total filers	Taxable income/filer ($ 000s)	Employment income (% of taxable income)
Toronto	69,393,183	1,869,220	37.12	65
Mississauga	16,667,053	471,730	35.33	77
Markham	8,926,687	229,960	38.82	71
Brampton	8,338,327	266,660	31.27	81
Oakville	6,209,599	110,210	56.34	73
Vaughan	4,725,095	114,930	41.11	79
Richmond Hill	4,411,392	113,900	38.73	74
Pickering	2,489,726	61,320	40.60	79
Newmarket	2,178,070	51,490	42.30	78
Ajax	2,090,139	54,390	38.43	81
Caledon	1,760,719	37,890	46.47	76
Halton Hills	1,660,121	38,770	42.82	76
Aurora	1,596,448	29,640	53.86	76
Milton	1,415,691	32,170	44.01	77
Orangeville	911,461	25,080	36.34	75
Georgina	882,448	27,650	31.91	75
King	838,456	13,600	61.65	69
Rest of Toronto CMA	3,207,086	77,640	41.31	73

Sources: The Conference Board of Canada; Canada Revenue Agency.

Sectoral Employment

	2004	2005	2006	2007f	2008f	2009f	2010f	2011f
Total employment (000s)	2,707	2,763	2,799	2,845	2,922	2,997	3,074	3,155
	2.2	*2.1*	*1.3*	*1.6*	*2.7*	*2.6*	*2.6*	*2.6*
Goods sector	662	652	617	615	632	641	650	660
	3.4	*–1.6*	*–5.4*	*–0.3*	*2.8*	*1.4*	*1.5*	*1.5*
Primary	9.7	12.1	12.2	11.5	11.0	11.2	11.4	11.6
	–0.6	*25.2*	*0.2*	*–5.5*	*–3.9*	*1.5*	*1.8*	*1.6*
Manufacturing	487.4	461.5	425.8	421.9	432.8	436.5	439.1	442.6
	4.2	*–5.3*	*–7.7*	*–0.9*	*2.6*	*0.9*	*0.6*	*0.8*
Construction	146.1	162.6	166.4	167.4	172.7	177.5	183.7	189.3
	–0.7	*11.3*	*2.3*	*0.6*	*3.2*	*2.8*	*3.5*	*3.1*
Utilities	18.9	15.6	12.3	13.9	15.3	15.7	16.0	16.3
	22.2	*–17.5*	*–21.0*	*13.3*	*10.1*	*2.2*	*2.0*	*2.1*
Services sector	2,045	2,111	2,183	2,231	2,291	2,356	2,424	2,495
	1.8	*3.2*	*3.4*	*2.2*	*2.7*	*2.9*	*2.9*	*3.0*
Transport & communications	224.6	224.3	248.3	242.2	243.8	248.2	252.9	257.7
	0.7	*–0.2*	*10.7*	*–2.4*	*0.7*	*1.8*	*1.9*	*1.9*
Wholesale & retail trade	420.8	444.9	457.0	479.9	493.6	507.5	521.5	536.1
	5.2	*5.7*	*2.7*	*5.0*	*2.8*	*2.8*	*2.8*	*2.8*
Finance, insurance & real estate	257.3	272.0	288.9	289.8	294.2	301.0	308.2	315.6
	8.7	*5.7*	*6.2*	*0.3*	*1.5*	*2.3*	*2.4*	*2.4*
Commercial services	688.3	686.3	694.6	713.4	738.5	761.5	784.7	809.9
	–1.9	*–0.3*	*1.2*	*2.7*	*3.5*	*3.1*	*3.1*	*3.2*
Non-commercial services	374.3	393.1	405.1	415.5	429.0	443.3	458.2	474.2
	3.9	*5.0*	*3.0*	*2.6*	*3.2*	*3.3*	*3.4*	*3.5*
Public administration	80.1	90.8	88.6	89.7	91.5	94.7	98.1	101.6
	–8.3	*13.3*	*–2.3*	*1.2*	*2.0*	*3.5*	*3.7*	*3.5*

Shaded area represents forecast data.
First line of employment data is in thousands and second line is percentage change.
Sources: The Conference Board of Canada; Statistics Canada.

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INTERNAL COST ALLOCATION MODEL

Over the past few years, THESL has adopted a cost allocation model for the use of vehicle, facilities and IT assets. The objective of this allocation model is to ensure all business units are accountable for managing the costs of the services they receive. Furthermore, this allocation methodology ensures that services provided to unregulated affiliates reflect their true cost.

ALLOCATION METHODOLOGY

The allocation methodology provides a recovery for the Fleet and Equipment Services ("FES"), Facilities and IT&S departments, which has the effect of moving operating costs from these departments to other business units or affiliates. The process for the allocation is as follows:

- FES, Facilities and IT&S prepare an overall budget for all their expected costs based on the service requirements provided by the business units;
- Following this budgeting exercise, standard rates are derived based on expected units for recoverable costs;
- The standard rates are then used to allocate the costs to each business unit based on expected usage;
- FES, Facilities and IT&S record the allocation to the business unit as a recovery (reduction of operating costs); and
- During the year, all actual costs are recorded in FES, Facilities and IT&S department along with a recovery from the business units to reflect actual usage of services.

The costs described in the following exhibits are presented on a gross basis for each area. This means the costs include the relevant allocation for FES, Facilities and IT&S. The

costs presented for FES, Facilities and IT&S are also presented on a gross-basis to provide an overall view of these costs for THESL.

FES

The allocation of costs to business units is done to optimize the number of vehicles and to allocate the vehicles to either maintenance or capital projects. The allocation is based on the number and type of vehicles. In the case of maintenance projects, the allocation provides for a transfer of operating costs from the FES department to the business units using the service. In the case of capital projects, the allocation provides for a transfer of operating costs to capital investment. The allocation to capital is based on the nature of the work performed and follows our labor costing methodology.

The costs included in the fleet allocation are mainly comprised of:

- Fleet compensation costs;
- Parts and material;
- Vehicle insurance, licensing and registration; and
- Fleet overhead.

FES also allocates costs related to large tools and laboratory services using the same methodology. Costs allocated to unregulated affiliates include a component for depreciation and return on assets.

FACILITIES

The allocation of Facilities costs to business units is done to optimize the use of space within our facilities. The allocation is based on square-footage and type of space. The allocation provides for a transfer of operating costs from the Facilities group to the business units.

The costs included in the Facilities allocation mainly consist of:

- Compensation costs;
- Property leases;
- Maintenance costs;
- Facilities overhead;
- Utilities costs;
- Property taxes; and
- PILs property taxes.

Facilities costs allocated to unregulated affiliates include a component for depreciation and return on assets.

IT&S

The allocation of IT&S costs to business units is done to optimize the use of technology assets. The allocation is based on the number and types of computers and software, number of phone lines and network accesses. The allocation provides for a transfer of operating costs in the IT&S department to the business units.

The costs included in the IT&S allocation are comprised mainly of:

- Software License costs;
- Maintenance costs;
- Equipment lease costs;
- Compensation costs; and
- IT&S overhead.

IT&S costs allocated to unregulated affiliates include a component for depreciation and return on assets.

CONDITIONS OF SERVICE

REVISION #6

Effective Date: January 23, 2007

The latest revisions to the Conditions of Service are highlighted in red.
Comments to these revisions can be emailed to rsironi@torontohydro.com.

Toronto Hydro-Electric System Limited

PREFACE

CONDITIONS OF SERVICE

The Distribution System Code (DSC) requires that every distributor produce its own "Conditions of Service" document. The purpose of this document is to provide a means for communicating the types and level of service available to the Customers and Consumers within Toronto Hydro's service area. The Distribution System Code requires that the Conditions of Service be readily available for review by the general public. In addition, the most recent version of the document must be provided to the Ontario Energy Board (OEB), which in turn will retain it on file for the purpose of facilitating dispute resolutions in the event that a dispute cannot be resolved between the Customer and its distributor.

The acceptance of supply of electricity or related services from Toronto Hydro constitutes the acceptance of a binding contract with Toronto Hydro which includes this Conditions of Service ("Conditions") and all terms thereunder. The person so accepting the supply of electricity or related services shall be liable for payment for same, and such contract shall be binding upon the person's heirs, administrators, executors, successors or assigns.

This document follows the form and general content of the Condition of Service template appended to the DSC. The template was prepared to assist distributors in developing their own "Conditions of Service" document based on current practice and the DSC. The text of the template is shown *in italics* throughout this Conditions, right after each of the subheadings. The template outlines the minimum requirements. However, as suggested by the DSC, Toronto Hydro has expanded on the contents to encompass local characteristics and other specific requirements.

Section 2 (Distribution Activities (General)) contains references to services and requirements that are common to all Customer classes. This section covers items such as Rates, Billing, Hours of Work, Emergency Response, Power Quality, Available Voltages and Metering.

Section 3 (Customer Class Specific) contains references to services and requirements specific to the respective Customer class. This section covers items such as Service Entrance Requirements, Delineation of Ownership, Special Contracts, etc.

Other sections include the *Glossary of Terms, Tables* and *References.*

Subsequent changes will be incorporated with each submission to the OEB.

The latest revisions to the Conditions of Service are highlighted in red. Comments to these revisions can be emailed to ***rsironi@torontohydro.com***. Toronto Hydro will file to the Ontario Energy Board a summary of public comments received from customers about the changes.

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Section 1 – INTRODUCTION

1 INTRODUCTION

1.1 Identification of Distributor and Service Area

In this section the distributor should identify its service area as defined in the Distributor's License

Toronto Hydro-Electric System Limited, referred to herein as "Toronto Hydro," is a corporation incorporated under the laws of the Province of Ontario and a distributor of electricity.

Toronto Hydro is licensed by the Ontario Energy Board ("OEB") to supply electricity to Customers as described in the Electricity Distribution License issued to Toronto Hydro on October 17, 2003 by the OEB and expiring October 16, 2023 ("Distribution License"). Additionally, there are requirements imposed on Toronto Hydro by the various codes referred to in the Distribution License and by the Electricity Act, 1998 and the Ontario Energy Board Act, 1998.

Toronto Hydro may only operate distribution facilities within its Licensed Territory as defined in its Distribution License. This service area is subject to change with the OEB's approval.

Nothing contained in this Conditions of Service ("this Conditions") or in any contract for the supply of electricity by Toronto Hydro shall prejudice or affect any rights, privileges, or powers vested in Toronto Hydro by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

1.1.1 Distribution Overview

Toronto Hydro distributes electrical power through 13.8kV and 27.6 kV primary distribution systems. On the 27.6 kV system all feeders are arranged to run in an open-loop fashion with open points between adjacent feeders. These feeders supply distribution transformers either directly or through 13.8 kV or 4 kV sub-distribution systems. There are presently four types of distribution design systems at the 13.8 kV primary voltage level:

- 13.8 kV underground radial
- 13.8 kV overhead open loop
- 13.8 kV underground open-loop
- 13.8 kV underground network

The underground network system is distinct from the other systems. This low-voltage secondary network system may be available to some Customers in the downtown core of the City of Toronto as a source of supply at 120/208 V, depending on the local capacity of the system and the energy requirements of the Customer.

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The supply of electricity by Toronto Hydro to any Customer will be at one of the following primary voltage levels: 27.6 kV or 13.8 kV depending on the proximity of the Customer's premises to the nearest distribution facility. For connection of a Customer at 4 kV level, Toronto Hydro will carry out a special study to justify the investment. The cost of this study may be charged to the Customer.

1.2 Related Codes and Governing Laws

This section should reference any legislation that is applicable to the distributor – Customer relationship

The supply of electricity or related services by Toronto Hydro to any Customer or Consumer shall be subject to various laws, regulations, and codes, including the provisions of the latest editions of the following acts, codes and licences:

1. Electricity Act, 1998 } part of the Energy Competition
2. Ontario Energy Board Act, 1998 } Act, 1998
3. Distribution Licence
4. Affiliate Relationships Code
5. Transmission System Code
6. Distribution System Code
7. Retail Settlement Code
8. Standard Supply Service Code

In the event of a conflict between this document and the Distribution License or regulatory codes issued by the OEB, or the Energy Competition Act, 1998 (the "Act"), the provisions of the Act, the Distribution License and associated regulatory codes shall prevail in the order of priority indicated above.

When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. Without limiting the foregoing, the work shall be conducted in accordance with the latest edition of the Ontario Occupational Health and Safety Act (OHSA), the Regulations for Construction Projects and the harmonized Electric Utility Safety Association (EUSA) rulebook.

1.3 Interpretations

This section should describe the rules for interpretation of the Conditions of Service document.

In this Conditions, unless the context otherwise requires:

- Headings, paragraph numbers and underlining are for convenience only and do not affect the interpretation of this Conditions;
- Words referring to the singular include the plural and vice versa;
- Words referring to a gender include any gender

Section 1 – INTRODUCTION

1.4 Amendments and Changes

This section should outline the process for making changes to this document. Include any public notice provisions.

The provisions of this Conditions in effect at the time Toronto Hydro signs the contract shall form part of any contract made between Toronto Hydro and any connected Customer, Consumer or Retailer. This Conditions supercedes all previous conditions of service, oral or written, of Toronto Hydro including any of its predecessor municipal electric utilities as of its effective date.

In the event of changes to this Conditions, Toronto Hydro will issue a notice with the Consumer's bill. Toronto Hydro may also issue a public notice in a local newspaper.

The Customer is responsible for contacting Toronto Hydro to ensure that the Customer has, or to obtain the current version of this Conditions. Toronto Hydro may charge a reasonable fee for providing the Customer with a copy of this document. The current version of this document is also posted on the Toronto Hydro website and can be downloaded from www.torontohydro.com.

1.5 Contact Information

This section should provide information on how a Customer can contact the distributor. Include such items as:

- ***Address of the distributor,***
- ***Telephone numbers,***
- ***Normal business hours, and***
- ***Emergency contact numbers.***

Toronto Hydro can be contacted 24 hours a day at 416-542-8000 or such other numbers as Toronto Hydro may advise through its website, invoices or otherwise. Normal working hours is Monday to Friday between 8:30 a.m. and 4:30 p.m. The mailing address is 14 Carlton Street, Toronto Ontario M5B 1K5.

1.6 Customer Rights

This section should outline the rights and obligations a Customer or embedded generator has with respect to the distributor that are not covered elsewhere in this document.

Toronto Hydro shall only be liable to a Customer and a Customer shall only be liable to Toronto Hydro for any damages that arise directly out of the willful misconduct or negligence:

- of Toronto Hydro in providing distribution services to the Customer;
- of the Customer in being connected to Toronto Hydro's distribution system; or
- of Toronto Hydro or Customer in meeting their respective obligations under this Conditions, their licences and any other applicable law.

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Notwithstanding the above, neither Toronto Hydro nor the Customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

The Customer shall indemnify and hold harmless Toronto Hydro, its directors, officers, employees and agents from any claims made by any third parties in connection with the construction and installation of an embedded generation facility or other electrical apparatus by or on behalf of the Customer.

1.7 Distributor Rights

This section should outline the rights a distributor has with respect to a Customer or embedded generator that are not covered elsewhere in this document.

1.7.1 Access to Customer Property

Toronto Hydro shall have access to Customer's property in accordance with section 40 of the *Electricity Act, 1998.*

1.7.2 Safety of Equipment

The Customer shall comply with all aspects of the Ontario Electrical Safety Code with respect to insuring that equipment is properly identified and connected for metering and operation purposes and will take whatever steps necessary to correct any deficiencies, in particular cross wiring situations, in a timely fashion. If the Customer does not take such action within a reasonable time, Toronto Hydro may disconnect the supply of electricity to the Customer.

The Customer shall not use or interfere with the facilities of Toronto Hydro except in accordance with a written agreement with Toronto Hydro. Toronto Hydro has the right to seal any point where a connection may be made on the line side of the metering equipment.

The Customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of Toronto Hydro, interfere with the proper and safe operation of Toronto Hydro's facilities or adversely affect compliance with any applicable legislation in the sole opinion of Toronto Hydro. Where an obstruction is discovered, Toronto Hydro will notify the Customer and provide a reasonable time for the Customer to correct any obstructions. If the Customer does not remove such obstruction within the reasonable time designated by Toronto Hydro, Toronto Hydro may disconnect the supply of electricity to the Customer and/or remove,

Section 1 – INTRODUCTION

relocate or, in the case of shrubs or other vegetation, trim such obstructions at the Customer's expense, and Toronto Hydro shall not be liable to the Customer for any damages arising as a result thereof, other than physical damage to facilities arising directly from entry on the Customer's property. Toronto Hydro's policies and procedures with respect to the disconnection process are further described in this Conditions.

1.7.3 Tree and Vegetation Management

To ensure public safety and the continued reliable operation of its distribution system Toronto Hydro will maintain clearance around its distribution lines on a cyclical or as-needed basis in close cooperation with the City's forestry department. The tree trimming cycle may vary depending on extent of storm damage, health of trees, and vegetation type.

Toronto Hydro will coordinate and maintain tree clearance around all its distribution lines that are located on public allowance. Toronto Hydro will also maintain tree clearance around its overhead lines over 750 Volts that may be located on private property at no cost to the Customer. Toronto Hydro will endeavour to discuss the planned re-clearing with property owners prior to work being performed in order to mitigate the impacts to the environment and the property. However, in the event of emergencies, Toronto Hydro may be unable to notify the property owner prior to performing the work.

Customers are responsible for all initial tree trimming for all new overhead lines that will be located on private property. Customers are also responsible for continuing tree trimming, tree and brush removal around service lines that are less than 750 Volts that are located on private property as well as around overhead lines over 750 Volts when these lines are owned by the Customer. Clearances must conform to the Electrical Safety Code.

To permit the safe clearance of trees and vegetation from overhead lines over 750 Volts located on private property Toronto Hydro will, upon at least ten days prior notice from the Customer, once each year during normal business hours, disconnect and reconnect the Customer's supply without charge.

1.7.4 Operating Control

The Customer shall provide a convenient and safe place, satisfactory to Toronto Hydro, for installing, maintaining and operating its equipment in, on, or about the Customer's premises or in, on, or about the public road allowance for non-metered connections. Toronto Hydro assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer's premises or in, on, or about the public road allowance for non-metered connections, or approaches thereto, or any acts, omissions or events

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beyond its control, or the negligence or willful misconduct of any Persons over whom Toronto Hydro has no control.

Unless an employee or an agent of Toronto Hydro, or other Person lawfully entitled to do so, no Person shall remove, replace, alter, repair, inspect or tamper with Toronto Hydro's equipment.

Customers will be required to pay the cost of repairs or replacement of Toronto Hydro's equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

The physical location on Customer's premises or the public road allowance for non-metered connections at which a distributor's responsibility for operational control of distribution equipment ends is defined by the Distribution System Code as the "operational demarcation point".

1.7.5 Repairs of Defective Customer Electrical Equipment

The Customer will be required to repair or replace any equipment owned by the Customer that may affect the integrity or reliability of Toronto Hydro's distribution system. If the Customer does not take such action within a reasonable time, Toronto Hydro may disconnect the supply of electricity to the Customer. Toronto Hydro's policies and procedures with respect to the disconnection process are further described in this Conditions.

1.7.6 Repairs of Customer's Physical Structures

The Customer is responsible for providing, maintaining, repairing and replacing, in a safe condition satisfactory to Toronto Hydro, all the Customer's civil infrastructure on private property or in the public road allowance for non-metered connections, including but not limited to poles, underground conduits, cable chambers, cable pull rooms, transformer rooms, transformer vaults, transformer pads, tap boxes, handwells, and junction boxes that Toronto Hydro deems required to house Toronto Hydro's Connection Assets.

Notwithstanding the above, unless otherwise agreed to by the parties and subject to the Customer providing an easement to Toronto Hydro, Toronto Hydro will provide, maintain, repair and replace those physical infrastructure (such as poles, underground conduits, cable chambers, transformer vaults, transformer pads, and switching vaults) that are required to house the primary distribution systems built along private streets that supply Customers of Multi-unit Residential developments (part of Class 3B). Effective November 15, 2004, Toronto Hydro will treat such infrastructure in the same way as those located in the public road allowance.

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The Customer shall inspect its facilities at regular intervals, including those facilities that house exposed high voltage equipment that are owned by Toronto Hydro. Given that access to the latter facilities is under the control of Toronto Hydro, the Customer shall contact Toronto Hydro at the applicable phone number:

- 416-542-3564 (former Toronto & East York)
- 416-542-3567 (former Scarborough, North York East of Yonge area)
- 416-542-3001, ext. 33065 (former Etobicoke, York, North York West of Yonge)

to make appropriate arrangements prior to inspecting its facilities and making repairs as required.

Where structural deficiencies to walls, ceiling, doors, vents, drains, or other Customer owned structures, are identified as a result of its inspection, Toronto Hydro will notify the Customer and provide a reasonable time for the Customer to correct any deficiencies to its facilities.

If the Customer does not carry out its repairs within a reasonable time, or the repairs are not considered adequate by Toronto Hydro or an inspection authority, Toronto Hydro may disconnect the supply of electricity to the Customer and carry out the repairs at the Customer's expense, and Toronto Hydro shall not be liable to the Customer for any damages arising as a result thereof, other than physical damage to facilities arising directly from entry on the Customer's property. Toronto Hydro's policies and procedures with respect to the disconnection process are further described in this Conditions.

1.8 Disputes

Any dispute between Customers or Retailers and the Distributor shall be settled according to the dispute resolution process specified in the Distributor Licence. In this section, the Distributor should outline the Customer Complaint and Dispute Resolution processes that has been established as a condition of licence.

If a Customer, Consumer or other market participant has a complaint about Toronto Hydro regarding services provided by Toronto Hydro under its Electricity Distribution License, the Consumer may contact one of Toronto Hydro's Customer Care representatives at 416-542-8000 during regular business hours, between 8:30 AM and 4:40 PM Monday to Friday, or e-mail the complaint to contactus@torontohydro.com.

Upon receipt of a complaint, a Toronto Hydro Customer Care representative will contact the Customer, Consumer or other market participant to acknowledge receipt of the complaint and, if possible, to resolve the complaint, and will investigate and follow-up on the complaint as required to resolve the complaint. If a Customer, Consumer or other market participant complaint cannot be resolved

Section 1 – INTRODUCTION

by contacting one of Toronto Hydro's Customer Care representatives, Toronto Hydro will refer the unresolved complaint to an independent third party complaints resolution agency that has been approved by the Ontario Energy Board. Until such time as the Ontario Energy Board approves such an independent third party complaints resolution agency, such complaints will be referred to the Ontario Energy Board, which has assumed this role.

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

2 DISTRIBUTION ACTIVITIES (GENERAL)

This section should include information that is applicable to all Customer classes of the distributor. Items that are applicable to only a specific Customer class are covered in Section 3.

2.1 Connections - Process and Timing

Under the terms of the Distribution System Code, Toronto Hydro has the obligation to either connect or to make an "Offer to Connect" any Customers that lie in its service area.

The Customer or its representative shall consult with Toronto Hydro concerning the availability of supply, the supply voltage, service location, metering, and any other details. These requirements are separate from and in addition to those of the Electrical Safety Authority (ESA). Toronto Hydro will confirm, in writing, the characteristics of the electricity supply.

The Customer or its authorized representative shall apply for new or upgraded electricity services and temporary power services in writing. The Customer is required to provide Toronto Hydro with sufficient lead-time in order to ensure:

(a) the timely provision of electricity supply to new and upgraded premises or
(b) the availability of adequate capacity for additional loads to be connected in existing premises.

Toronto Hydro shall make every reasonable effort to respond promptly to a Customer's request for connection. Toronto Hydro shall respond to a Customer's written request for a Customer connection within 15 calendar days of receipt of the written request. Toronto Hydro will make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the Customer before the offer can be made. Requirements regarding the process and timing of embedded generation facility connections are set forth in Section 3.5.

Toronto Hydro shall make every reasonable effort to respond promptly to another distributor's request for connection. Toronto Hydro shall provide an initial consultation with another distributor regarding the connection process within thirty (30) days of receiving a written request for connection. A final offer to connect the distributor to Toronto Hydro's distribution system shall be made within ninety (90) days of receiving the written request for connection, unless other necessary information outside the distributor's control is required before the offer can be made.

If special equipment is required or equipment delivery problems occur, then longer lead times may be necessary. Toronto Hydro will notify the Customer of any extended lead times.

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In addition to any other requirements in this Conditions, the supply of electricity is conditional upon Toronto Hydro being permitted and able to provide such a supply, obtaining the necessary apparatus, material, and easements, and constructing works to provide the service. Should Toronto Hydro not be permitted or able to do so, it is under no responsibility to the Customer whatsoever and the Customer releases Toronto Hydro from any liability in respect thereto.

Requirements regarding Connection Agreements are set forth in Sections 2.1.7.4, 3.5, 3.6 and 3.7, respectively for load Customer, a Generator, Wholesale Market Participant, and Embedded Distributor.

2.1.1 Building that Lies Along

In this section, the Distributor should describe the standard connection allowance or charge used by the Distributor in its service territory and describe any variable connection fees that would be charged beyond the standard allowance.
The Distributor also may stipulate in this section other terms and conditions by which a Customer requesting a Connection must abide, as long as it is within the terms of the DSC code.

For the purpose of this Conditions "lies along" means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where Toronto Hydro has distribution facilities of the appropriate voltage and capacity.

Under the terms of the Distribution System Code, Toronto Hydro has the obligation to connect (under Section 28 of the Electricity Act, 1998) a building or facility that “lies along” its distribution line, provided:

a) the building can be connected to Toronto Hydro’s distribution system without an expansion or enhancement and,
b) the service installation meets the conditions listed in the Conditions of Service of the distributor that owns and operates the distribution line.

The location of the Customer's service entrance equipment is subject to the approval of Toronto Hydro and the Electrical Safety Authority.

2.1.1.1 Connection Charges

Toronto Hydro shall recover costs associated with the installation of connection assets by Customer Class via Basic Connection Costs through the economic evaluation for Expansions and Variable Connection Costs, collected directly from the Customer, as applicable.

The Variable Connection Costs shall be calculated as the costs associated with the installation of Connection assets **above and beyond** the Standard Allowance for Basic Connection as described in Tables 1.1, 1.2 and 1.3.

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Toronto Hydro will recover this Variable Connection Costs, which shall be based on actual cost, directly from the Customer.

2.1.2 Expansions / Offer to Connect

Under the terms of the DSC, a Distributor has the Obligation to make an Offer to Connect any Building that is in the distributor' s service territory that cannot be connected without an expansion or enhancement, or "lies along" its distribution system, but may be denied connection for the reasons described in subsection 2.1.3 of the distributor's Conditions of Service.

The Offer to Connect must be fair and reasonable and be based on the distributor's design standard. The Offer to Connect also must be made within a reasonable time from the request for connection.

In this section, the Distributor should outline, in detail, the process followed to determine any required capital contributions. This section also should describe any fixed connection fees as well as variable connection fees, by Customer class.

Effective January 23, 2007, if Toronto Hydro proposes to connect a new Customer load to Toronto Hydro's distribution system facilities or upgrade a connection to an existing Customer, and an expansion of Toronto Hydro's distribution system is required, Toronto Hydro will perform an economic evaluation of the expansion project in accordance with the Capital Contribution policy set out in Section 2.1.2.2 to determine if the future revenue from the Customer(s) will pay for the costs pertaining to the expansion including but not limited to:

1) on-going operating, maintenance & administration (whether actually incurred or apportioned on the manner set forth below) costs - *"OM&A Costs"*
2) the historical average distribution system enhancement capital cost per kW- "*Enhancement Costs"*
3) the distribution system expansion capital cost - *"New Expansion Costs"*
4) the basic cost of connection outlined in Tables 1.1, 1.2 and 1.3 – "Basic Connection Costs"

(Enhancement Costs, New Expansion Costs and Basic Connection Costs, collectively "Expansion Fees")

Enhancement Costs are those which Toronto Hydro has incurred over the past three (3) years to increase the distribution system capacity to accommodate new Customer loading facilities on Toronto Hydro's distribution system, consistent with the Toronto Hydro's planning, design, and construction standards, and include the following:

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- The construction of new distribution feeders & circuits (overhead or underground, single phase or multi-phase) along its existing distribution facilities that are intended to be serving other Customers
- The upgrading of existing conductors with higher capacity conductors.
- Conversions of existing lower voltage distribution facilities to higher voltage distribution facilities with greater supply capacity.
- The installation of switching and protection facilities associated with the construction and/or upgrading of existing distribution feeders and circuits.
- The construction of new and/or upgrading of distribution stations and transformation facilities associated with the additional loading.
- Capital contributions paid by the distributor for upstream additional facilities, typically owned by a transmitter.

Toronto Hydro has aggregated its historical reinforcement capital expenditures over the past three (3) years (and will update them on an annual basis) and has derived an average cost reinforcements in $/kW that will apply to all expansion projects.

In addition, Toronto Hydro will include in the economic evaluation for a Customer requiring an expansion all those capital expenditures that are associated with the installation of new distribution facilities & circuits when these are essentially required to accommodate new Customer loading. The above distribution facilities & circuits shall meet all of the following criteria:

- Are required to accommodate new Customer load
- Are not intended to be serving other Customers, other than "non-forecasted" Customers referred to in Section 2.1.2.7.
- Are consistent with Toronto Hydro's planning, design, and construction standards.

For the purpose of determining OM&A Costs Toronto Hydro will use system average operating, maintenance and administrative expenditures as a proxy for incremental OM&A expenditures and apportion them as fixed costs (for Rate Class 1 and 2) or as a function of $/kW of demand (for Rate Class 3, 4, and 5).

The Expansion Fees are in addition to any Variable Connection Fees. Refer to Table 1.1, 1.2 and 1.3 in Section 5 for each Customer Class.

For the purpose of establishing the "Estimated Incremental Demand" to be used in the economic evaluation, the Customer shall provide a valid estimate of the proposed incremental demand for evaluation and acceptance by Toronto Hydro. If the Customer and Toronto Hydro are unable to agree on a valid incremental demand for new Class 3, 4, and 5 Customers or in the absence of adequate billing history for existing Customers, Toronto Hydro will set the "Estimated

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Incremental Demand" to equal to 90% of the "incremental installed transformer capacity".

Using the "Estimated Incremental Demand", Toronto Hydro shall then calculate the "Estimated Incremental Revenues" of new Customers using the "fixed charge" and the "variable charge" that have been approved by the Ontario Energy Board for the Rate Class applicable to each individual new meter installed in connection with the expansion project. For existing Customers Toronto Hydro shall apportion the "fixed charge" based on the ratio between the incremental load and the combined load.

In performing the economic evaluation, should the Net Present Value (NPV) of the costs and revenues associated with the Expansion be less than zero, a capital contribution in the amount of the shortfall is required. Toronto Hydro has elected to collect this shortfall from the Customer in accordance with its Capital Contribution policy as outlined in Section 2.1.2.2.

The amount charged by Toronto Hydro to a generator to construct the expansion to connect a generation facility to the Toronto Hydro distribution system shall not exceed the generator's share of the present value of the projected capital costs and on-going maintenance costs for the equipment. Projected revenue and avoided costs from the generation facility shall be assumed to be zero, unless otherwise determined by rates approved by the Ontario Energy Board. The methodology and inputs that Toronto Hydro will use to calculate this amount are presented in Appendix B of the Distribution System Code.

2.1.2.1 Offer to Connect & Alternative Bid Work

Toronto Hydro will provide one offer to connect to the Customer for any plans submitted to Toronto Hydro for an expansion project, at no expense to the Customer. If the Customer submits revised plans, Toronto Hydro may provide a new firm offer to connect for revised plans at the Customer's expense.

If all of the following conditions are met, Toronto Hydro may proceed with the expansion work for a project without giving the Customer a formal Offer to Connect:

- the incremental demand is less than 200kW
- the expansion work does not require a capital contribution from the Customer; and
- the construction work for the expansion involves work only with existing circuits.

If the project meets all of the following conditions:

- the project requires a capital contribution from the Customer and
- the construction work would not involve work with existing circuits,

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then, Toronto Hydro will also advise the Customer that he or she has the choice to obtain alternative bids from a qualified contractor for the construction of those connection and expansion facilities that are specified in the Offer to Connect as contestable work for which the Customer may obtain an alternative bid.

To qualify to undertake contestable work, contractors shall submit a "Construction Contractor Qualification Application" and meet the requirements posted at: http://www.torontohydro.com/electricsystem/customer_care/cond_of_services/index.cfm no later than 30 business days prior to their selection by the customer to undertake contestable work. To avoid delay in the start of the contestable work the Customer shall engage a contractor that is qualified.

In addition, Toronto Hydro does not make any representation or warranty regarding any contractor selected by the Customer to do any work regardless of whether the contractor has completed the requirements set by Toronto Hydro or not and shall have no liability to the Customer in respect of such work.

Toronto Hydro will also include in the Offer to Connect or by separate document an estimate of any costs that will be incurred by Toronto Hydro in the event that the Customer decides to pursue an alternative bid for the contestable work, including but not limited to the following:

- costs for additional design, engineering, or installation of facilities required to complete the project that were made in addition to the original Offer to Connect;
- costs for inspection or approval of the work performed by the contractor hired by the Customer, and
- costs for making the final connection of the new facilities to the Toronto Hydro distribution system.

Within sixty (60) days of receiving the Offer to Connect, the Customer shall return a signed copy of the Offer to Connect indicating acceptance of the offer, or, notify Toronto Hydro of its rejection of Toronto Hydro's Offer to Connect and of its decision to pursue an alternative bid.

If the Customer decides to pursue an alternative bid, the Customer and his qualified contractor shall only use materials that meet the same specifications as Toronto Hydro approved materials (i.e. same manufacturers and same part numbers). Once the Customer has hired a qualified contractor, the Customer may request and obtain from Toronto Hydro the listing of approved materials that may be required for the alternative bid work.

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Upon receipt of notice that a Customer will be pursuing an alternative bid Toronto Hydro shall advise the Customer of the amount the Customer shall be required to pay to Toronto Hydro in respect of costs to be incurred by Toronto Hydro in connection with the expansion project. Even if no expansion deposit is otherwise required hereunder, the Customer shall post an expansion deposit in the amount of 10% of the value of contestable work in accordance with Section 2.1.2.3.

2.1.2.2 Capital Contribution Policy

The capital contribution policy elected by Toronto Hydro shall be consistent with the policy outlined below for each Customer Class:

Class 1 – Residential Single Service: No Transformation required on private property

- Overhead or Underground: *Capital contribution **not** collected from Customer*

Class 2 - General Service, (Below 50 kW): No Transformation required on private property

- Overhead or Underground: *Capital contribution **not** collected from Customer*

Class 3 - General Service (50 kW – 999 kW): *Capital contribution collected from Customer*

Class 4 - General Service (1000 kW – 4999 kW): *Capital contribution collected from Customer.*

Class 5 – Large User (5000 kW and above)*: Capital contribution collected from Customer*

For the purpose of determining the amount of Capital Contribution payable by a Customer the following clarification and exception shall apply:

- Condominium apartments and apartment buildings that have a demand less than 1,000 kW are part of Class 3A General Services
- Condominium townhouse units intended to remain in private property are part of Class 3B General Service
- Townhouse units built (or intended to be) fronting public road allowances are part of Class 3C "Residential Subdivision"
- Townhouse units built as "freehold" (i.e. on property owned by the individual townhouse owner) are part of Class 3C "Residential Subdivision"
- Low-rise residential developments involving more than 5 lots regardless of demand are classified as Class 3C "Residential Subdivision".

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However, notwithstanding the treatment of capital contribution, Toronto Hydro shall in all cases calculate the "Estimated Incremental Revenues" of new Customers using the "fixed charge" and the "variable charge" that have been approved by the Ontario Energy Board for the Rate Class applicable to each individual new meter installed in connection with the expansion project.

To determine the amount of Capital Contribution required from a Class 3, 4, or 5 Customer for an expansion project, Toronto Hydro will perform an economic evaluation by inputting the project specific information together with a set of standardized assumptions and specific annual parameters into a proprietary "Business Economic Model" developed for Toronto Hydro in accordance with the methodology and inputs outlined in Appendix B of the Distribution System Code ("Economic Evaluation").

2.1.2.2.1 Offer to Connect – Content & Process

Based on the output of its Economic Evaluation, Toronto Hydro will set out in the Offer to Connect the following, as applicable:

(a) Whether the offer is a firm offer or an estimate of costs that would be revised in the final payment to reflect actual costs incurred;

(b) the amount of the capital contribution;

(c) the calculation used to determine the amount of the capital contribution including all of the assumptions and inputs used to produce the economic evaluation;

(d) a statement as to whether the offer includes work for which the Customer may obtain an alternative bid, and, if so, the process by which the Customer may obtain the alternative bid;

(e) a description of, and costs for, the contestable work and the uncontestable work associated with the expansion broken down into the following categories:

  (i) labour (including design, engineering and construction);

  (ii) materials ;

  (iii) equipment; and

  (iv) overhead costs (including administration);

(f) the amount for any additional costs that will occur as a result of the alternative bid option being chosen including, but not limited to, inspection and final connection costs ("additional costs for alternative bid work");

(g) the amount for the basic cost of connection; and

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(h) the expansion deposit, including 10% of the cost of the contestable work, where applicable.

If there is a conflict between an Offer to Connect and this Conditions, the Offer to Connect shall govern.

2.1.2.2.2 Transfer Price for Contestable Work

The transfer price for the contestable work shall be the lower of the cost to the Customer to construct the expansion facilities or the amount set out in the initial Offer to Connect to do the contestable work less the "additional costs for alternative bid".

If the Customer does not provide the cost to construct the expansion facilities to Toronto Hydro within 30 days of all of the new facilities being energized, then the amount of the transfer price shall be the amount set out in the initial Offer to Connect to do the contestable work.

2.1.2.2.3 Final Economic Evaluation & Capital Contribution Settlement

If the Offer to Connect is an estimate of the costs to construct the expansion and not a firm offer, Toronto Hydro will carry out a final Economic Evaluation once the facilities are energized. The final Economic Evaluation will be based on forecasted revenues, actual costs incurred for the uncontestable work, and the transfer price to be paid to the Customer for the contestable work, where applicable.

If the Offer to Connect is a firm offer and the Customer has exercised the alternative bid option, Toronto Hydro will carry out a final Economic Evaluation once the facilities are energized. The final Economic Evaluation will be based on the amounts used in the firm offer for costs and forecasted revenues, plus any transfer price to be paid to the Customer for the contestable work, where applicable.

If the required capital contribution amount resulting from the final Economic Evaluation differs from the required capital contribution amount resulting from the initial Economic Evaluation, Toronto Hydro will obtain from the Customer, or credit the Customer for, any difference between the two amounts.

Toronto Hydro will provide the Customer with the calculation used to determine the final capital contribution amount including all of the

assumptions and inputs used to produce the final Economic Evaluation at no cost to the customer.

2.1.2.3 Expansion Deposit

To keep Toronto Hydro harmless in respect of the Expansion Fees and OM&A Costs for a New Expansion, an Offer to Connect may require Class 3 Customers requesting multi-phase developments, Class 4 Customers (Commercial and Industrial) and Class 5 Customers (Commercial and Industrial) to provide an expansion deposit to cover the difference between the actual Expansion Fees and the amount of the capital contribution paid by the Customer, in accordance with Toronto Hydro's Economic Evaluation of the expansion.

In addition, where a Customer (regardless of its Class) intends to exercise the alternative bid option, even if no expansion deposit is otherwise required hereunder, the Customer shall post an expansion deposit in an amount equal to 10% of the cost of the contestable work as set out in the Offer to Connect ("warranty portion of the expansion deposit"). Toronto Hydro will retain this portion of the expansion deposit for a warranty period of up to two years and may apply such deposit to any work required to repair the expansion facilities within the two-year warranty period.

The two-year warranty period begins at the end of the Realization Period. The Realization Period for a project ends:

- For residential developments, upon the first to occur of the materialization of the last forecasted connection in the expansion project, or five (5) years after energization of the new facilities, and
- For commercial and industrial developments, upon the first to occur of the materialization of the last forecasted demand, or five (5) years after energization of the new facilities.

Toronto Hydro shall return to the Customer the unapplied portion of the expansion deposit, if any, at the end of the two-year warranty period.

The expansion deposit must be either in the form of (i) cash or (ii) an irrevocable commercial letter of credit issued by a Schedule I bank as defined in the Bank Act, or (iii) surety bond, but the form of deposit must expressly provide for its use to cover the events for which it is held as a deposit. The expansion deposit including the portion compromising the warranty expansion deposit shall be in addition to any other charges or deposits that may be required by Toronto Hydro and shall be provided **prior**

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to the commencement of any expansion work or the installation of any connection assets.

Except for the warranty portion of the expansion deposit which shall be retained for the duration of the warranty period, once the facilities are energized, Toronto Hydro shall agree to a reduction at the end of each 365-day period in the amount of the expansion deposit in an amount calculated by multiplying the original expansion deposit by a percentage derived by dividing the actual connections (for residential developments) or actual demand (for commercial and industrial developments) completed or materialized in that 365-day period by the total number of connections (for residential developments) or actual demand (for commercial and industrial developments) contemplated in the original Offer to Connect. (For example, if twenty percent of the forecasted connections or demand materialized in a year, then Toronto Hydro will return to the customer twenty percent of the original expansion deposit.)

However, if after five (5) years from the energization date of the facilities the total number of connections (for residential developments) or the actual demand (for commercial and industrial developments) contemplated by the Original Offer to Connect have not materialized, Toronto Hydro shall retain any cash held as an expansion deposit, or be entitled to realize on any letter of credit or bond held as an expansion deposit and retain any cash resulting therefrom, with no obligation to return any portion of such monies to the Customer at any time.

If the Customer has provided any expansion deposit in the form of cash, any portion of the expansion deposit held as cash returned to the Customer shall include interest on the returned amount from the date of receipt of the full amount of the expansion deposit at the Prime Business Rate set by the Bank of Canada less 2 percent.

2.1.2.4 Supply Agreement

Class 3,4 and 5 Customers may be required to enter into a Supply Agreement with Toronto Hydro to clarify the responsibilities of each party pertaining to the construction and maintenance of the expansion and or connection assets.

2.1.2.5 Rebates of Capital Contribution

In scenarios where Toronto Hydro is required to incur New Expansion Costs solely for the connection of a Customer, the Customer will be required to pay Toronto Hydro 100% of the calculated shortfall. If within 5 years from the connection date, non-forecasted Customers are connected to this new

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plant without any further capital costs, Toronto Hydro will rebate the first Customer for the portion of the "New Expansion" that is shared with non-forecasted Customers. Toronto Hydro will provide such a rebate at the time and in conjunction with the Settlement of each relevant subsequent Capital Contribution.

The amount of the rebate to the first Customer shall be the shared portion of the expansion equally contributed to by all "non-forecasted Customers". The amount of capital contribution previously paid by the first Customer also constitutes the "upset" limit of the rebate to the first Customer.

2.1.2.6 Feeder Capacity Optimization

Toronto Hydro will provide service to the Customer during the Realization Period based upon the Estimated Incremental Demand indicated in the Offer to Connect that has been signed by the Customer. However, unused capacity will not be reserved past the Realization Period.

After the Realization Period Toronto Hydro reserves the right to examine the Customer's peak demand with a view to optimizing its feeder capacity. If the actual peak demand is lower than the Estimated Incremental Demand, then Toronto Hydro will adjust downwards its internal peak demand forecast and may re-assign any unused capacity if it determines this is appropriate to meet other demand needs.

After the Realization Period the Customer shall obtain the consent of Toronto Hydro prior to effecting any substantial increase its peak demand, regardless of the Estimated Incremental Demand set forth in the Offer to Connect, or through past demand history.

2.1.3 Connection Denial

The DSC sets outs the conditions for a Distributor to deny connections. The DSC lists reasons for which a Building that "lies along" a distribution line may be refused connection to that line. This section should describe reasons why a distributor may not be obligated to connect the Customer and provide additional details, where relevant, about specific conditions that may result in a refused connection in accordance with the DSC code. For example, the criteria for establishing an unsafe connection or a connection, which adversely affects the system, should be further documented within the Conditions of Service.

The Distribution System Code provides for the ability of a Distributor to deny connections. Toronto Hydro is not obligated to connect a Customer within its service area if the connection would result in any of the following:

- Contravention of existing laws of Canada or the Province of Ontario, including the Ontario Electrical Safety Code

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- Violations of conditions in Toronto Hydro's Licence
- Use of a Toronto Hydro distribution system line for a purpose that it does not serve and that Toronto Hydro does not intend to serve
- Adverse affect on the reliability or safety of Toronto Hydro's distribution system
- Public safety reasons or imposition of an unsafe work situation beyond normal risks inherent in the operation of Toronto Hydro's distribution system
- A material decrease in the efficiency of the Toronto Hydro's distribution system
- A materially adverse effect on the quality of distribution services received by an existing connection
- If the person requesting the connection owes Toronto Hydro money for distribution services
- Potential increases in monetary amounts that already are in arrears with Toronto Hydro
- If an electrical connection to Toronto Hydro's distribution system does not meet Toronto Hydro's design requirements
- Any other conditions documented in Toronto Hydro's Conditions.

If Toronto Hydro refuses to connect a Customer in its service area that lies along one of its distribution lines, Toronto Hydro shall inform the person requesting the connection of the reasons for the denial, and where Toronto Hydro is able to provide a remedy, make an Offer to Connect in accordance with Section 2.1.2 of this Conditions. If Toronto Hydro is not capable of resolving the issue, it is the responsibility of the Customer to do so before a connection can be made.

2.1.4 Inspections Before Connections

In this section, the Distributor should state the requirement for inspection by the Electrical Safety Authority prior to the commencement of electricity supply.

All Customer electrical installations shall be inspected and approved by the Electrical Safety Authority and must also meet Toronto Hydro's requirements. Toronto Hydro requires notification from the Electrical Safety Authority of this approval prior to the energization of a Customer's supply of electricity. Services that have been disconnected for a period of six months or longer must also be re-inspected and approved by the Electrical Safety Authority, prior to reconnection.

Temporary services, typically used for construction purposes and for a period of twelve months or less, must be approved by the Electrical Safety Authority and must be re-inspected should the period of use exceed twelve months.

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Customer owned substations must be inspected by both the Electrical Safety Authority and Toronto Hydro.

Transformer rooms shall be inspected and approved by Toronto Hydro prior to the installation of Toronto Hydro's equipment.

Duct banks shall be inspected and approved by Toronto Hydro prior to the pouring of concrete and again before backfilling. The completed ducts must be rodded by the site contractor in the presence of a Toronto Hydro inspector and shall be clear of all extraneous material. A mandrel, approved by Toronto Hydro for a nominal diameter of duct, will be passed through each duct. In the event of ducts blocked by ice, the owner's representative will be responsible for clearing the ducts prior to the cable installation. Connection to existing concrete duct banks or cable chamber shall be done only by a contractor approved by Toronto Hydro. All work done on existing Toronto Hydro's plant must be authorized by Toronto Hydro and carried out in accordance with all applicable safety acts and regulations.

Provision for metering shall be inspected and approved by Toronto Hydro prior to energization.

2.1.5 Relocation of Plant

This section should specify the distributor' s policy with respect to requests for relocation of plant and the conditions under which the requestor is or may be required to pay for the relocation of plant should be specified. Sharing arrangements also should be noted.

When requested to relocate distribution plant, Toronto Hydro will exercise its rights and discharge its obligations in accordance with existing acts, by-laws and regulations including the *Public Service Works on Highways Act*, agreements, easements and law. In the absence of existing agreements, Toronto Hydro is not obligated to relocate the plant. However, Toronto Hydro shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner will include a response to the requesting party that explains the feasibility or unfeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

In the course of maintaining and enhancing Toronto Hydro's distribution plant, Toronto Hydro may need to relocate distribution plant that is owned by Toronto Hydro. Costs associated with such relocation(s) shall be borne by Toronto Hydro, except that, in accordance with Section 3.2(g) hereof, if the Customer requests that such maintenance or construction activities be done outside Toronto Hydro's normal working hours, the Customer shall pay for any incremental costs incurred by Toronto Hydro as a result thereof.

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2.1.6 Easements

In this section, any requirements for easements should be described.

To maintain the reliability, integrity and efficiency of the distribution system, Toronto Hydro has the right to have supply facilities on private property and to have easements registered against title to the property. Easements are required where facilities serve property other than property where the facilities are located and/or where Toronto Hydro deems it necessary.

The Customer will prepare at its own cost any required reference plan to the satisfaction of Toronto Hydro. Easement documents are prepared by the Toronto Hydro Legal Services Department. Four copies of the deposited reference plan must be supplied to Toronto Hydro prior to the preparation of the easement documents. Details will be provided upon application for service.

2.1.7 Contracts

This section should outline the types of contracts that are available for each type of Customer, including standard, implied and special contracts. Connection agreements and operating agreements should be listed and referenced as appendices to the Conditions of Service, if applicable.

2.1.7.1 Contract for New or Modified Electricity Service

Toronto Hydro shall only connect a Customer for a new or modified supply of electricity upon receipt by Toronto Hydro of the following:

- a completed and signed contract for service in a form acceptable to Toronto Hydro;
- payment to Toronto Hydro of any applicable connection fee;
- an inspection and approval by the Electrical Safety Authority of the electrical equipment for the new service; and
- a Connection Agreement as requested or required pursuant to Section 2.1.7.4.

2.1.7.2 Implied Contract

In all cases, notwithstanding the absence of a written contract, Toronto Hydro has an implied contract with any Customer that is connected to Toronto Hydro's distribution system and receives distribution services from Toronto Hydro. The terms of the implied contract are embedded in Toronto Hydro's Conditions of Service, the Rate Handbook, Toronto Hydro's rate schedules, Toronto Hydro's licence, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code, all as amended from time to time.

The acceptance of supply of electricity or related services from Toronto Hydro constitutes a binding contract with Toronto Hydro, which includes

this Conditions and all terms thereunder. The person so accepting the supply of electricity or related services shall be liable for payment for same, and such contract shall be binding upon such person's heirs, administrators, executors, successors or assigns.

If Toronto Hydro has not received a request to open an account in the name of the occupant of the property, or in the event the electricity is used by a person(s) unknown to Toronto Hydro, then the cost for electricity consumed by such person(s) is due and payable by the owner(s) of such property.

2.1.7.3 Special Contracts

Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- construction sites
- mobile facilities
- non-permanent structures
- special occasions, etc.
- embedded generation facilities

2.1.7.4 Connection Agreements

Toronto Hydro may require a Customer to enter into a Connection Agreement in a form acceptable to Toronto Hydro. Until such time as the Customer executes such a Connection Agreement with Toronto Hydro, the Customer shall be deemed to have accepted and agreed to be bound by all of the terms in the Connection Agreement attached to this as Schedule A to Section 6.

A generator shall enter into a Connection Agreement in a form specified by these Conditions, or otherwise acceptable to Toronto Hydro. Until such time as the generator executes such a Connection Agreement with Toronto Hydro, the generator shall be deemed to have accepted and agreed to be bound by all of the Connection Agreement Terms and Conditions attached to this Conditions as Schedule B3 to Section 6, and the terms of any operating schedule delivered to it from time to time by Toronto Hydro.

A Wholesale Market Participant shall enter into a Connection Agreement in a form acceptable to Toronto Hydro. Until such time as the Wholesale Market Participant executes such a Connection Agreement with Toronto Hydro, the Wholesale Market Participant shall be deemed to have accepted and agreed to be bound by all of the Connection Agreement Terms and Conditions attached to this Conditions as Schedule C to Section 6, and the

terms of any operating schedule delivered to it from time to time by Toronto Hydro.

An Embedded Distributor shall enter into a Connection Agreement in a form acceptable to Toronto Hydro. Until such time as the Embedded Distributor executes such a Connection Agreement with Toronto Hydro, the Embedded Distributor shall be deemed to have accepted and agreed to be bound by all of the terms in this Conditions that apply to such Embedded Distributor.

Toronto Hydro shall make a good faith effort to enter into a Connection Agreement with a distributor connected to Toronto Hydro's distribution system in accordance with the requirements in the Distribution System Code issued by the Ontario Energy Board.

If there is a conflict between a Connection Agreement with a Customer, Generator, Wholesale Market Participant or Embedded Distributor and this Conditions of Service, the Connection Agreement shall govern.

2.1.7.5 Payment by Building Owner

The owner of a Building is responsible for paying for the supply of electricity by Toronto Hydro to the owner's Building except for any supply of electricity to the Building by Toronto Hydro in accordance with a request for electricity by an occupant(s) of the Building.

A Building owner wishing to terminate the supply of electricity to its Building must notify Toronto Hydro in writing. Until Toronto Hydro receives such written notice from the Building owner, the Building owner and/or the occupant(s), as applicable, shall be responsible for payment to Toronto Hydro for the supply of electricity to such Building. Toronto Hydro may refuse to terminate the supply of electricity to an owner's Building when there are occupant(s) in the Building (i.e. during certain periods of the winter).

Where a property has been vacated by an occupant of the property, and Toronto Hydro has not been notified that a new occupant should be billed for the electricity supplied to the property and the owner has not submitted a written request to disconnect the electricity supply, Toronto Hydro will bill the owner for the electricity supply to the property until such time as Toronto Hydro is notified by the owner or a new occupant that the occupant should be billed for the electricity supply.

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2.1.7.6 Opening and Closing of Accounts

A Consumer who wishes to open or close an account for the supply of electricity by Toronto Hydro shall contact Toronto Hydro's Call Centre by phone, by written request (including requests submitted by facsimile), through Toronto Hydro's web site, or other means acceptable to Toronto Hydro.

The Consumer shall be responsible for payment to Toronto Hydro for the supply of electricity to the property up to the date Toronto Hydro is notified of the termination of the account.

2.2 Disconnection

In this section, the Distributor should specify under what circumstances it has the right or obligation to disconnect a Customer. This section also should outline the business processes used by the distributor, including notification and timing provisions.

Toronto Hydro reserves the right to disconnect service for reasons not limited to:

- Contravention of the laws of Canada or the Province of Ontario, including the Ontario's Electrical Safety Code".
- A material adverse effect on the reliability and safety of Toronto Hydro's distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of Toronto Hydro's distribution system.
- A material decrease in the efficiency of Toronto Hydro's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection
- Inability of Toronto Hydro to perform planned inspections and maintenance.
- Failure of the Consumer or Customer to comply with a directive of Toronto Hydro that Toronto Hydro makes for purposes of meeting its licence obligations.
- Overdue amounts payable to Toronto Hydro including the non-payment of a security deposit.
- Electrical disturbance propagation caused by Customer equipment that is not corrected in a timely fashion
- Any other conditions identified in this Conditions

Toronto Hydro may disconnect the supply of electricity without notice in accordance with a court order, or for emergency, safety or system reliability reasons.

A Customer intending to demolish any buildings that house Toronto Hydro's distribution equipment shall notify Toronto Hydro at least four (4) months in advance of demolition. The Customer shall pay Toronto Hydro for the costs of removing all electrical equipment owned by Toronto Hydro that is located on private

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property. Provided the Customer has made all necessary arrangements, Toronto Hydro shall remove all its equipment by the date agreed to with the Customer.

2.2.1 Disconnection & Reconnection – Process and Charges

Immediately following the due date, steps will be taken to collect the full amount of the electricity bill. If the bill is still unpaid sixteen calendar days after the due date and seven calendar days after a disconnect notice has been given to the Customer, the service may be disconnected and not restored until payment arrangements satisfactory to Toronto Hydro have been made, including costs of reconnection. Such discontinuance of service does not relieve the Customer of the liability for arrears or other applicable charges for the balance of the term of contract, nor shall Toronto Hydro be liable for any damage to the Customer's premises resulting from such discontinuance of service, other than physical damage to facilities arising directly from entry on the Customer's property. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing.

Notwithstanding the foregoing, Toronto Hydro shall not shut off the supply of electricity to a property for non-payment as set forth above during such periods as may be prescribed by regulations under the *Electricity Act, 1998*. Upon discovery that a hazardous condition or disturbance propagation (feedback) exists, Toronto Hydro will notify the Customer to rectify the condition at once. If the Customer fails to make satisfactory arrangements to remedy the condition within seven calendar days after a disconnect notice has been given to the Customer, the service may be disconnected and not restored until satisfactory arrangements to remedy the condition have been made. Toronto Hydro shall not be liable for any damage to the Customer's premises resulting from such discontinuance of service, except for physical damage to facilities arising directly from Toronto Hydro's entry on the Customer's property. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing.

Upon receipt of a Disconnection request by the Customer, Toronto Hydro will disconnect and/or remove Toronto Hydro's connection assets at the Customer's cost as outlined in Table 2 in Section 5 of this Conditions.

2.2.2 Unauthorized Energy Use

Notwithstanding the provisions of Section 2.1.7.2 (Implied Contract) and Section 2.1.7.5 (Payment by Building Owner), Toronto Hydro reserves the right to disconnect the supply of electricity to a building or property where the building or property has, or appears to have, been used for unlawful purposes, including energy diversion or theft of power. The supply of electricity to the building or property may not be reconnected for the existing customer until

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Toronto Hydro receives full payment from the existing customer of all reasonable costs and losses incurred by Toronto Hydro arising from the unauthorized energy use, including costs of inspections, repair costs, commodity costs, disconnection costs, and reconnection costs. If other than the existing customer requests reconnection, Toronto Hydro may recover any reconnection charges approved by the Ontario Energy Board.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guaranty of Supply

In this section, the Distributor should specify its limitations on the guaranty of supply. The Distributor also should reference the provisions for "Powers of Entry" described in section 40 of the Electricity Act, 1998.

Toronto Hydro will endeavour to use reasonable diligence in providing a regular and uninterrupted supply of electricity but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Consumer or Customer by reason of any failure in respect thereof.

Consumers or Customers requiring a higher degree of security than that of normal electricity supply are responsible to provide their own back-up or standby facilities. Consumers or Customers may require special protective equipment at their premises to minimize the effect of momentary power interruptions.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of Toronto Hydro's electricity supply.

During an emergency, Toronto Hydro may interrupt supply to a Consumer in response to a shortage of supply of electricity, or to effect repairs on its distribution system, or while repairs are being made to Consumer or Customer-owned equipment. Toronto Hydro shall have rights to access property in accordance with section 40 of the *Electricity Act, 1998* and any successor acts thereto.

To assist with distribution system outages or emergency response, Toronto Hydro may require a Consumer or Customer to provide Toronto Hydro with emergency access to Consumer or Customer-owned distribution equipment that normally is operated by Toronto Hydro or Toronto Hydro-owned equipment on Consumer's property.

2.3.2 Power Quality

This section should outline the guidelines and policies to which the Distributor will endeavor to adhere to in conveying electricity supply, such as service voltage guidelines and outage notification processes. This section

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also should indicate the process the distributor uses for handling voltage disturbances and power quality testing and remedial action.

This section also should include conditions under which supply of electricity to Customers may be interrupted. Additionally, conditions under which the supply may become unreliable or intermittent should be described.

2.3.2.1 Power Quality Testing

Where a Consumer or Customer provides evidence or data indicating that a power quality or EMI problem may be originating from Toronto Hydro's distribution system, Toronto Hydro will perform investigative analysis to attempt to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and power quality monitoring.

Upon determination that the cause resulting in the power quality concern originates from the Toronto Hydro distribution system, where it is deemed a system delivery issue and where industry standards are not met, Toronto Hydro will recommend and/or take appropriate mitigation measures. Toronto Hydro will take appropriate actions to control power disturbances found to be detrimental to the Consumers or Customers. If Toronto Hydro is unable to correct the problem without adversely affecting other Toronto Hydro Consumers or Customers, then it is not obligated to make the corrections. Toronto Hydro will use appropriate industry standards (such as IEC or IEEE standards) and good utility practice as a guideline. If the problem lies on the Customer side of the system, Toronto Hydro may seek reimbursement from the Customer for the costs incurred in its investigation.

2.3.2.2 Prevention of Voltage Distortion on Distribution

Customers having non-linear load shall not be connected to Toronto Hydro's distribution system unless power quality is maintained by implementing proper corrective measures such as installing proper filters, and/or grounding. Further, to ensure the distribution system is not adversely affected, power electronics equipment installed must comply with IEEE Standard 519-1992. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

2.3.2.3 Obligation to Help in the Investigation

If Toronto Hydro determines the Customer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on Toronto Hydro's distribution system, the Customer is obligated to help Toronto Hydro by providing required equipment information, relevant data and necessary access for monitoring the equipment.

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The Customer shall assist in the investigation and resolution of power quality problems by:

(a) maintaining and providing Toronto Hydro with a detailed log of exact times and dates of poor power quality;
(b) ensuring corrective measures such as filters and/or grounding are installed for non-linear loads connected to the distribution system;
(c) assisting Toronto Hydro in determining whether the Customer's equipment may be a source of undesirable system disturbances; and
(d) ceasing operation of equipment deemed to be the cause of system disturbances until satisfactory remedial action has been taken;

The Consumer or Customer should be aware that some distribution system events such as capacitor switching may cause problems with highly sensitive equipment, and the Consumer or Customer shall be responsible for mitigating these effects.

2.3.2.4 Timely Correction of Deficiencies

If an undesirable system disturbance is being caused by Customer's equipment, the Customer will be required to cease operation of the equipment until satisfactory remedial action has been taken by the Customer at the Customer's cost. If the Customer does not take such action within a reasonable time, Toronto Hydro may disconnect the supply of electricity to the property.

2.3.2.5 Notification for Interruptions

Although it is Toronto Hydro's policy to minimize inconvenience to Consumers, it is necessary to occasionally interrupt a Consumer 's supply of electricity to allow work on Toronto Hydro's electrical system. Toronto Hydro will endeavor to provide such Consumers with reasonable notice of planned power interruptions. However, interruption times may change due to inclement weather or other unforeseen circumstances. Toronto Hydro shall not be liable in any manner to such Consumers for failure to provide such notice of planned power interruptions or for any change to the schedule for planned power interruptions.

During an emergency, Toronto Hydro may interrupt supply of electricity to a property without notice in response to a shortage of supply of electricity or to effect repairs on Toronto Hydro's distribution system or while repairs are being made to Customer-owned equipment, or to conduct work of an emergency nature involving the possibility of injury to persons or damage to property or equipment.

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2.3.2.6 Notification to Consumers on Life Support

Consumers who require an uninterrupted source of power for life support equipment must provide their own equipment for these purposes. Consumers with life support system are encouraged to inform Toronto Hydro of their medical needs and their available backup power. These Consumers are responsible for ensuring that the information they provide Toronto Hydro is accurate and up-to-date.

With planned interruptions, the same procedure as prescribed in section 2.3.2.5 will be observed. For those unplanned power interruptions that extend beyond two hours and the time expected to restore power is longer than what was indicated by Consumers (registered on life support) as their available backup power, Toronto Hydro will endeavor to contact these Consumers but will not be liable in any manner to the Consumers for failure to do so.

2.3.2.7 Emergency Interruptions for Safety

Toronto Hydro will endeavour to notify Consumers prior to interrupting the supply of electricity. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or potentially damaging to Toronto Hydro or the public, the supply of electricity may be interrupted without notice.

2.3.2.8 Emergency Service (Trouble Calls)

Toronto Hydro will exercise reasonable diligence and care to deliver a continuous supply of electricity to the Consumer. However, Toronto Hydro cannot guarantee a supply that is free from interruption.

When power is interrupted, the Consumer should first ensure that failure is not due to blowing of fuses within the installation. If there is a partial power failure, the Consumer should obtain the services of an electrical contractor to carry out necessary repairs. If, on examination, it appears that Toronto Hydro's main source of supply has failed, the Consumer should report these conditions at once to Toronto Hydro's Call Centre by calling 416-542-8000.

Toronto Hydro operates a Call Centre 24 hours a day to provide emergency service to Consumers. Toronto Hydro will initiate restoration efforts as rapidly as practicable.

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2.3.2.9 Outage Reporting

Depending on the outage, duration and the number of Consumers affected, Corporate Communications of Toronto Hydro may issue a news release to advise the general public of the outage. In turn, news radio stations may call for information on a 24-hour basis when they hear of an outage.

2.3.3 Electrical Disturbances

This section should outline the guidelines to which the Distributor and the Customer will be expected to adhere to regarding electrical disturbances.

Toronto Hydro shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in Section 2.3.5 of this Conditions.

Voltage fluctuations and other disturbances can cause flickering of lights and other serious difficulties for Consumers connected to Toronto Hydro's distribution system. Customers must ensure that their equipment does not cause disturbances such as harmonics and spikes that might interfere with the operation of adjacent Consumer equipment. Equipment that may cause disturbances includes large motors, welders and variable speed drives, etc. In planning the installation of such equipment, the Customer must consult with Toronto Hydro.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms. Toronto Hydro will assist in attempting to resolve any such difficulties at the Customer's expense.

Consumers who may require an uninterrupted source of power supply or a supply completely free from fluctuation and disturbance must provide their own power conditioning equipment for these purposes.

2.3.4 Standard Voltage Offerings

This section should specify the voltages that the distributor may provide to each type of Customer, based on their supply requirements. This section should include both the primary and secondary voltages that are available. Additionally, any physical or geographic constraints on a particular voltage, or conditions under which voltages may not be provided should be detailed in this section.

2.3.4.1 Primary Voltage

The primary voltage to be used will be determined by Toronto Hydro for both Toronto Hydro-owned and Customer-owned transformation. Depending on the voltage of the plant that "lies along", the preferred primary voltage will be at 27.6/ 16 kV grounded wye, three phase, four-wire

system. However, in the downtown core of the City of Toronto the primary voltage will be 13.8/8 kV grounded wye, three phase, four wire; or 13.8 kV three phase, three wire, depending on the area.

2.3.4.2 Supply Voltage

Depending on the voltage of the plant that "lies along" Toronto Hydro's distribution system, the preferred secondary voltage will be at 120/240 V, single phase, and 208/120 V, 600/347 V, three phase. Depending on the system availability in the area, 208/120 V two phase, three wire may be supplied in place of 120/240 V.

The supply voltage governs the limit of supply capacity for any Customer.

When supply is from secondary street circuits the demand load shall be as follows:

(i) at 120/240 V, single phase; 208/120 V, two phase, three wire up to 75 kVA demand load, or

(ii) at 600/347 V, three phase, four wire up to 80 kVA demand load, or

(iii) at both 120/240 V, single phase and 600/347 V, three phase, four wire up to 100 kVA sum total demand load, or

(iv) at 208/120 V, three phase, four wire up to 100 kVA demand load,

For supply exceeding the above capacity, the Customer is required to provide a transformer, pad mounted or in a building vault, on private property to receive supply of electricity up to the following capacities:

When a pad-mounted transformer is used the demand load shall be as follows:

(i) fed from 4.16/2.4 kV primary at 208/120 V or 600/347 V, three phase, four wire supply is available for loads up to 300 kVA demand load, or

(ii) fed from 13.8/8 kV primary at 208/120 V or 600/347 V, three phase, four wire supply is available for loads up to 750 kVA demand load, or

(iii) fed from 27.6/16 kV primary at 208/120 V or 600/347 V, three phase, four wire, supply is available for loads up to 750 kVA and 1500 kVA demand load respectively.

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When a transformer vault is used:
fed from 4.16/2.4 kV primary at 208/120 V or 600/347 V, three phase, four wire supply is available for loads up to 300 kVA demand load,

(i) fed from 13.8/8 kV primary at 208/120 V or 600/347 V, three phase, four wire, supply is available for loads up to 1500 kVA or and 2500 kVA demand load respectively depending on system availability in the area, (i.e.- three phase),

(ii) fed from 27.6/16 kV primary at 208/120 V or 600/347 V, three phase, four wire, supply is available for loads up to 1500 kVA and 2500 kVA demand load respectively (i.e. three phase).

When the Customer requires voltages other than at the available supply voltage, or demands by a single occupant exceed the limits indicated above, the Customer shall consult with Toronto Hydro. Toronto Hydro may advise the Customer of any special conditions and requirements to obtain such non-standard services. However, Toronto Hydro is under no obligations to provide any non-standard services.

When supply is available from the underground network system, permissible demand load will depend upon the local capacity of the system and specific circumstances. Should a new service or a change in service involving the network system not be possible then the requirements for a Customer to provide transformation as detailed in the rest of this section 2.3.4.2 still apply.

2.3.4.3 Multiple Connections to Main Distribution System

Customers will be generally connected to one point of the main Toronto Hydro distribution system. Toronto Hydro may offer a second point of connection to another point of the main Toronto Hydro distribution system when:

a) the Customer is fed by the 13.8 kV underground radial system as defined in section 1.1.1 or
b) the Customer's point load exceeds the maximum set in section 2.3.4.2 for service from a transformer vault.

In the case of Customers supplied from the 13.8 kV underground radial system, Customers will not be eligible to ask for service from Sketch 1(h) unless the demand exceeds the limit set for transformer vaults as set out in section 2.3.4.2.

Where multiple connections exist, and unless otherwise agreed by Toronto Hydro, load should be distributed evenly across all active connections. Load

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must not be transferred from one active connection to another without the permission of Toronto Hydro.

Toronto Hydro will determine the location of any connection points to its main distribution system. Although Toronto Hydro will give consideration to arguments relating to a need for diversity of supply, it retains the right to determine in its sole discretion, not to allow a second point of connection to another part of the main distribution system.

2.3.5 Voltage Guidelines

This section should specify what voltages the distributor' s Customers can reasonably expect, with reference to CSA Standard CAN3-235 current edition.

Toronto Hydro maintains service voltage at the Customer's service entrance within the guidelines of C.S.A. Standard CAN3-C235-83 (or latest edition), which allows variations from nominal voltage as shown on the table below:

Nominal Voltage	**Voltage Variation Limits**			
	Extreme Operating Conditions			
		Normal Operating Conditions		
Single Phase				
120/240	106/212	110/220	125/250	127/254
Three Phase 4 Wire				
208/120	190/110	194/112	216/125	220/127
416/240 (*)	220/380	224/388	250/432	254/440
600/347	530/306	550/318	625/360	635/367

(*) 416/240 is no longer a standard voltage offered by Toronto Hydro

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions as noted above, improvement or corrective action will be taken by Toronto Hydro on a planned and programmed basis, but not necessarily on an emergency basis. Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action should be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

Toronto Hydro shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter or host distributor. Toronto Hydro shall not be liable for any delay or failure in the performance of any of its obligations under this

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Conditions due to any events or causes beyond the reasonable control of Toronto Hydro, including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes ("Force Majeure").

2.3.6 Emergency Back-up Generation Facilities

Distributors should include the following statements in this section:

- ***Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that Customer emergency generation does not back feed into the Distributor's system.***

- ***Customers with permanently connected emergency generation equipment shall notify their Distributor regarding the presence of such equipment.***

Any other requirements the Distributor imposes on Customers with emergency backup generation facilities should be described in this section.

Customers or Consumers with a portable or permanently connected backup generation facility (including an embedded generation facility that is used exclusively for load displacement purposes) shall comply with all applicable criteria of the Ontario Electrical Safety Code. In particular, the Customer or Consumer shall ensure that the backup generation facility does not parallel with Toronto Hydro's system without a proper interface protection and an appropriate Connection Agreement, and does not adversely affect Toronto Hydro's distribution system.

Customers considering installing a Closed-Transition switch shall notify Toronto Hydro and shall submit a protection study that satisfies Toronto Hydro's technical requirements. The Customer shall obtain a written approval from Toronto Hydro prior to operation of the switch in closed transition mode. Closed-Transition switches must not parallel the generator with Toronto Hydro's distribution system for longer than 100 ms under any circumstances. Customers or Consumers with permanently connected backup generation facility shall notify Toronto Hydro regarding the presence of such equipment and shall enter into such agreements as may be requested, or required, under this Conditions.

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2.3.7 Metering

This section should specify the options available to a Customer for metering equipment. The Distributor also should outline the technical requirements for meter installations including location and associated main switch.

Toronto Hydro will supply, install, own, and maintain all meters, instrument transformers, ancillary devices, and secondary wiring that are required for revenue metering.

An Ontario Energy Board-licensed generator connected to the Toronto Hydro distribution system that sells energy and settles through the Toronto Hydro retail settlement process shall install a four-quadrant interval meter.

A Customer with an embedded generation facility connected to the Toronto Hydro distribution system shall install its own meter in accordance with the Toronto Hydro metering requirements. The Customer shall obtain a written approval from Toronto Hydro with respect to technical details of the metering installation.

Where practical, metering for an embedded generation facility shall be installed at the point of supply. If it is not practical to install the meter at the point of supply, Toronto Hydro will apply loss factors to the generation output in accordance with the loss factors applied for retail settlements and billing.

Where an embedded generation facility metering installation does not conform to Measurement Canada standards or the Customer cannot confirm accuracy class of its instrument transformers, the Customer shall have the metering installation, including instrument transformers, tested, and provide satisfactory test results to Toronto Hydro. Toronto Hydro will apply a Measurement Canada correction factor to meter readings until such time as standards conformance is achieved.

Metered Market Participants in the Independent Electricity Market Operator ("IESO") administered wholesale market must meet or exceed all IESO metering requirements. All Embedded Generation Facilities of 10 MW or larger must meet or exceed all IESO metering requirements.

2.3.7.1 General

Describe the Distributor' s access to meter installation requirements here.

Toronto Hydro will typically install metering equipment at the Customer supply voltage. The Customer must provide a convenient and safe location, satisfactory to Toronto Hydro, for the installation of meters, wires and ancillary equipment. Meters for new or upgraded residential services will be mounted outdoors on a meter socket approved by Toronto Hydro.
No person, except those authorized by Toronto Hydro, may remove,

connect, or otherwise interfere with meters, wires, or ancillary equipment owned by Toronto Hydro.

The Customer will be responsible for the care and safekeeping of Toronto Hydro meters, wires and ancillary equipment on the Customer's premises. If any Toronto Hydro equipment installed on Customer premises is damaged, destroyed, or lost other than by ordinary wear and tear, tempest or lightning, the Customer will be liable to pay to Toronto Hydro the value of such equipment, or at the option of Toronto Hydro, the cost of repairing the same.

The location allocated by the owner for Toronto Hydro metering shall provide direct access for Toronto Hydro staff and shall be subject to satisfactory environmental conditions, some of which are:

- Maintain a safe and adequate working space in front of equipment, not less than 1.2 metres (48") and a minimum ceiling height of 2.1 metres (84")
- Maintain an unobstructed working space in front of equipment, free from, or protected against, the adverse effects of moving machinery, vibration, dust, moisture or fumes

Where Toronto Hydro deems self-contained meters to be in a hazardous location, the Customer shall provide a meter cabinet or protective housing.

Any compartments, cabinets, boxes, sockets, or other workspace provided for the installation of Toronto Hydro's metering equipment shall be for the exclusive use of Toronto Hydro. No equipment, other than that provided and installed by Toronto Hydro, may be installed in any part of the Toronto Hydro metering workspace.

2.3.7.1.1 Metering Requirements for Multi-Unit Sites and Condominium Corporations

In addition to a bulk-meter, to promote conservation Toronto Hydro will provide a standard individual meter for each unit of a new Multi-unit site, or a condominium at no direct charge to the Customer. Customers wishing to have new multi-unit site, or a condominium, equipped with alternative electronic metering shall make suitable arrangements satisfactory to Toronto Hydro with Toronto Hydro.

For existing condominium corporations that fall under the Condominium Act, 1998, each condominium corporation shall make arrangements with Toronto Hydro to install no later than December 31, 2010, smart meters or a smart sub-metering system, for each unit on the property. Installation and

operation of a smart sub-metering system will require a licence from the Ontario Energy Board.

In each case, the Customer will comply with the detailed technical requirements set forth at: http://www.torontohydro.com/electricsystem/customer_care/cond_of_services/index.cfm

a) Individual Metering and House Metering Requirements for Multi-Unit Sites
Where individual units in a multi-unit site, or condominium, are to be metered individually, the building owner (or operator, or property manager, or condominium corporation) shall enter into a contract with Toronto Hydro for the supply of electrical energy for all common or shared services. Common or shared services typically include lighting of all common areas shared by the tenants, or units owners, or which supply common services such as heating, air conditioning, hot water heating, elevators, and common laundry facilities. In such cases, in addition to the individual meter for each unit, a separate house meter (or halls meter) will be required to measure the energy used for all common or shared services.

b) Requirements for Existing Multi-Unit Sites with no House Meter
Where units in an existing multi-unit site, or condominium, are metered individually and shared services are supplied through one or more unit meters (i.e. the existing multi-unit site is not equipped with a house meter or halls meter), the building owner shall enter into a contract with Toronto Hydro for the supply of electricity to such unit(s).

For better clarity, the house meter account(s) shall be in the multi-unit site, or condominium, owner's name, who shall also be responsible for the payment for all energy supplied through such meter(s).

2.3.7.1.2 Main Switch and Meter Mounting Devices

The Customer's main switch immediately preceding the meter shall be installed so that the top of the switch is 1.83 m or less from the finished floor and shall permit the sealing and padlocking of:

(a) the handle in the "open" position; and
(b) the cover or door in the closed position.
Meter mounting devices for use on Commercial/Industrial accounts shall be installed on the load side of the Customer's main switch and be located indoor.

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The Customer is required to supply and install a Toronto Hydro approved meter socket for the use of Toronto Hydro's self-contained socket meters for the main switch ratings and supply voltages listed in Table 5 in Section 5 of this Conditions.

The Customer is required to supply and install a meter cabinet to contain Toronto Hydro's metering equipment for the main switch ratings and supply voltages listed in Table 6 in Section 5 of to this Conditions.

Meter centers installed for individual metering applications must meet the requirements specified in Table 8 in Section 5 of to this Conditions.

The Customer shall permanently and legibly identify each metered service with respect to its specific address, including unit or apartment number. The identification shall be applied to all service switches, circuit breakers, meter cabinets, and meter mounting devices.

2.3.7.1.3 Service Mains Limitations

The metering provision and arrangement for service mains in excess of either 600 A or 600 V shall be submitted to Toronto Hydro for approval before building construction begins. Additional standards and requirements for services metered above 600 V can be made available upon request.

2.3.7.1.4 Special Enclosures

Specially constructed meter entrance enclosures will be permitted for outdoor use upon Toronto Hydro's approval of a written application for use.

2.3.7.1.5 Meter Cables

The Customer shall provide meter loops having a length of 610-mm in addition to the length between line and load entry points.
Line and load entry points shall be approved by Toronto Hydro prior to installation. Where more than two conductors per phase are used, the connectors shall be provided by the Customer (see Table 6 in Section 5 of this Conditions for required cabinets). Mineral insulated, solid or hard drawn wire conductors are not acceptable for meter loops.

Any variation from the above must first be checked and approved by Toronto Hydro prior to installation.

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2.3.7.1.6 Barriers

Barriers are required in each section of switchgear or service entrance equipment between metered and unmetered conductors and/or between sections reserved for Toronto Hydro use and sections for Customer use.

2.3.7.1.7 Doors

Side-hinged doors shall be installed over all live electrical equipment where Toronto Hydro personnel may be required to work (i.e. line splitters, unmetered sections of switchgear, breakers, switches, metering compartments, meter cabinets and enclosures). These hinged doors shall have provision for sealing and padlocking. Where bolts are used, they shall be of the captive knurled type. All outer-hinged doors shall open no less than 135°. All inner-hinged doors shall open to a full 90°.

2.3.7.1.8 Auxiliary Connections

All connections to circuits such as fire alarms, exit lights and Customer instrumentation shall be made to the load side of Toronto Hydro's metering.

No Customer equipment shall be connected to any part of the Toronto Hydro metering circuit.

2.3.7.1.9 Working Space

Clear working space shall be maintained in front of all equipment and from all side panels in accordance with the Ontario Electrical Safety Code.

2.3.7.2 Current Transformer Boxes

Where current transformers are required, the Distributor should outline the technical requirements to be followed for such installations.

Where instrument transformers are incorporated in low voltage switchgear, the size of the chamber and number of instrument transformers shall be as shown in Table 7 in Section 5 of to this Conditions. A separate meter cabinet must be supplied and installed by the Customer, located to the satisfaction of Toronto Hydro and as close as possible to the instrument transformer compartment.

The cabinet and the compartment will be connected by an empty 1½ inch conduit, the length of which shall not exceed 30 m, and which shall include a maximum of three 90° bends. The conduit will be provided for the

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exclusive use of Toronto Hydro. No fittings with removable covers are permitted.

The meter cabinet shall be grounded by a minimum #6 copper grounding conductor, not installed in the above conduit. The Customer shall install a strong nylon or polyrope pull line in the conduit, with an excess of 1500 mm loop left at each end.

The final layout and arrangements of components must be approved by Toronto Hydro prior to fabrication of equipment.
Where two or more circuits are totalized, or where remote totalizing is involved, or where instrument transformers are incorporated in high voltage switchgear (greater than 750 V), Toronto Hydro will issue specific metering requirements.

2.3.7.3 Interval Metering

Where interval metering is required or requested, the Distributor should outline the technical requirements to be followed for such installations. Included with the technical specifications should be the conditions under which interval metering will be supplied.

Interval meters will be installed for all new or upgraded services where the peak demand is forecast to be 200 kW or greater, or for any Customer wishing to participate in the spot market pass-through pricing. Prior to the installation of an interval meter, the Customer must provide a ½ inch conduit from their telephone room to the meter cabinet. Toronto Hydro will arrange for the installation of a telephone line, terminated in the meter cabinet for the exclusive use of Toronto Hydro to retrieve interval meter data. The Customer will be responsible for the installation of the telephone infrastructure and ongoing monthly costs of operating the phone line. The phone line will be Toronto Hydro owned, direct dial, voice quality, active 24 hours per day, and energized prior to meter installation.

Other Customers that request interval metering shall compensate Toronto Hydro for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and reverification of the meter, installation and ongoing provision of communication line or communication link with the Customer's meter, and cost of metering made redundant by the Customer requesting interval metering.

2.3.7.4 Meter Reading

This section should outline the requirements for access to meters for the purposes of obtaining readings and the process to be used if a reading is not obtained.

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The Customer or Consumer must provide or arrange free, safe and unobstructed access during regular business hours to any authorized representative of Toronto Hydro for the purpose of meter reading, meter changing, or meter inspection. Where premises are closed during Toronto Hydro's normal business hours, the Customer or Consumer must, on reasonable notice, arrange such access at a mutually convenient time.

2.3.7.5 Final Meter Reading

This section should outline any requirements associated with obtaining a final meter reading on termination of a contract for service.

When a service is no longer required, the Customer or Consumer shall provide sufficient notice of the date the service is to be discontinued so that Toronto Hydro can obtain a final meter reading as close as possible to the final reading date. The Customer or Consumer shall provide access to Toronto Hydro or its agents for this purpose. If a final meter reading is not obtained, the Consumer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading, as determined by Toronto Hydro.

2.3.7.6 Faulty Registration of Meters

In this section, the Distributor should outline the process for dealing with metering errors.

Metering electricity usage for the purpose of billing is governed by the federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. Toronto Hydro's revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, Toronto Hydro will determine the correction factors based on the specific cause of the metering error and the Consumer's electricity usage history. The Consumer shall pay for all the electricity supplied a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by Toronto Hydro, due regard being given to any change in the characteristics of the installation and/or the demand. If Measurement Canada, Industry Canada determines that the Consumer was overcharged, Toronto Hydro will reimburse the Consumer for the amount incorrectly billed.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill

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calculation, the billing correction will apply for the duration of the error. Toronto Hydro will correct the bills for that period in accordance with the regulations under the Electricity and Gas Inspection Act.

2.3.7.7 Meter Dispute Testing

This section should outline the process by which a Customer can dispute a meter measurement or read and seek redress.

Metering inaccuracy is an extremely rare occurrence. Most billing inquiries can be resolved between the Customer or Consumer and Toronto Hydro without resorting to the meter dispute test.

Either Toronto Hydro or the Customer or Consumer may request the service of Measurement Canada to resolve a dispute. If the Customer or Consumer initiates the dispute, Toronto Hydro will charge the Customer or Consumer a meter dispute fee if the meter is found to be accurate and Measurement Canada rules in favor of the utility.

2.4 Tariffs and Charges

2.4.1 Service Connection

The Distributor should outline the rates that have been established for providing the Customer with a connection to the electrical distribution system and all services provided by the Distributor as per the rules and regulations laid out by all applicable codes.

Charges for distribution services are made as set out in the Schedule of Rates available from Toronto Hydro. Notice of Rate revisions shall be published in major local newspapers. Information about changes will also be mailed to all Consumers with the first billing issued at revised rates.

2.4.1.1 Customers Switching to Retailer

There are no physical service connection differences between Standard Service Supply (SSS) customers and third party retailers' customers. The supply of electricity to both types of customers is delivered through Toronto Hydro's distribution system with the same distribution requirements. Therefore, all service connection requirements applicable to the SSS customers are applicable to third party retailers' customers.

2.4.1.2 Supply Deposits & Agreements

Where an owner proposes the development of premises that require Toronto Hydro to place orders for equipment for a specific project and before actual construction begins, the owner is required to sign the necessary Supply

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Agreement and furnish a suitable deposit before such equipment is ordered by Toronto Hydro.

An irrevocable (standby) letter of credit from a financial institution acceptable to Toronto Hydro and in a form acceptable to Toronto Hydro is acceptable in lieu of a cash deposit.

2.4.2 Energy Supply

This section should outline the process the Distributor has established for the following:

- ***Provision of Standard Service Supply to the Customer, per the rules and regulations laid out in the Retail Settlement Code and the Standard Service Supply Code.***
- ***Provision of Supply to the Customer through a Retailer, per the rules and regulations laid out in the Retail Settlement Code.***
- ***Wheeling of energy and all associated tariffs.***

2.4.2.1 Standard Service Supply (SSS)

All Toronto Hydro Consumers are Standard Service Supply (SSS) Consumers until Toronto Hydro is informed by the Consumer or the Consumer's authorized retailers of their switch to a competitive electricity supplier. The Service Transfer Request (STR) must be made by the Consumer or the Consumer's authorized retailer.

2.4.2.2 Retailer Supply

Consumers transferring from Standard Service Supply (SSS) to a retailer shall comply with the Service Transfer Request (STR) requirements as outlined in sections 10.5 through 10.5.6 of the Retail Settlement Code. All requests shall be submitted as electronic file and transmitted through EBT Express. Service Transfer Request (STR) shall contain information as set out in section 10.3 of the Retail Settlement Code.

If the information is incomplete, Toronto Hydro shall notify the retailer or Consumer about the specific deficiencies and await a reply before proceeding to process the transfer.

2.4.2.3 Wheeling of Energy

All Customers or Consumers considering delivery of electricity through the Toronto Hydro distribution system are required to contact Toronto Hydro for technical requirements and applicable tariffs.

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2.4.3 Deposits

This section should outline any deposit and prudential requirements the Distributor has established for providing a Customer with Distribution Services, supply through Standard Service Supply or through a Retailer, per the rules and regulations laid out in the Distribution System Code.

Whenever required by Toronto Hydro, including, but not limited to, as a condition of supplying or continuing to supply Distribution Services, Consumers and Customers shall provide and maintain security in an amount that Toronto Hydro deems necessary and reasonable. Toronto Hydro will not discriminate among customers with similar risk profiles or risk related factors except where expressly permitted under the Distribution System Code.

Except for Consumers or Customers who meet the security deposit waiver conditions described below, all Consumers or Customers are required to provide an account security deposit to Toronto Hydro, which, at the Consumer's or Customer's election, must be in the form of (i) cash, cheque or Money Order, or, if approved by Toronto Hydro, Visa or MasterCard or (ii) for non residential Consumers or Customers an automatically renewing irrevocable commercial letter of credit from a bank defined in the *Bank Act, 1991*, c.46. Toronto Hydro will not accept third party guarantees.

The amount of the account security deposit will be based on the billing factor times the estimated average bill during the most recent 12 months. The billing factors are as follows:

- 2.5 for monthly billed Consumers or Customers
- 1.75 for bi-monthly billed Consumers or Customers

Where there is no established historical electricity consumption information for the service premises, the deposit will be based on a reasonable estimate using information from a like property used for similar purposes.

Where the Consumer or Customer has one disconnection in the relevant period, the highest bill in the period will be used for the calculation of the deposit. The maximum amount determined by this calculation may not be exceeded

If requested by the Consumer or Customer, Consumers or Customers will be permitted to pay the security deposit in equal installments over a maximum of 4 months.

The electricity service is subject to disconnection when over fifty percent of the security deposit remains unpaid or a payment arrangement is not honoured.

The security deposit may be waived based on the following criteria:

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

(a) The Consumer or Customer has a good payment history based on the most recent customer history with some portion in the most recent 24 months, during which time the Consumer or Customer:

- had no more than one (1) notice of disconnection; AND
- had no more than one (1) payment returned for insufficient funds ("NSF"); AND
- had no disconnect/collection trip.

The minimum time period for good payment history is as follows:

- Residential - 1 year
- Non-residential <50 kW demand rate class - 5 years
- All other classes - 7 years

or

(b) The Consumer or Customer provides a letter from another electricity or gas distributor in Canada confirming good payment history. The letter must contain information consistent with the good payment criteria described in this document.

or

(c) The Consumer or Customer (other than those in a >5000 kW demand rate class) provides a satisfactory credit check at its expense. The acceptable Equifax Credit scores are as follows:

- ***Residential*** - Consumer Score of 700 or greater
- ***Business*** - Commercial Score of 20 or lower

or

(d) Residential account deposits may be waived where the Consumer or Customer enrolls in the Toronto Hydro's pre-authorized payment plan and supplies at least two pieces of identification information, provided that a deposit will be required if the pre-authorized payment plan is cancelled.

or

(e) The customer is a bulk-metered residential condominium as defined in the Condominium Act, 1998 and has provided Toronto Hydro with a signed declaration attesting to their legal status as a residential condominium corporation.

The security deposit may be reduced for non residential Consumers or Customers with 50 kW or greater demand, based on the following criteria:

Where the Consumer or Customer has a credit rating from a recognized credit rating agency, (Dominion ***Bond Rating Service, Standard & Poors or Moody's***) the maximum amount of deposit required will be reduced as follows:

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

Credit Rating (Using Standard & Poor's Rating Terminology	Allowable Reduction
AAA- and above	100%
AA-, AA, AA+	95%
A-, From A, A+ to below AA	85%
BBB-, From BBB, BBB+ to below A	75%
Below BBB-	0%

Equivalent ratings from other bond rating agencies would apply for the same reductions.

In the above case, the commodity price used to calculate the deposit shall be the same as the price used by the IESO for the purpose of determining maximum net exposures and prudential support obligations for market participants other than distributors, low-volume Consumers and designated Consumers.

Interest will accrue monthly on security deposits commencing when the total deposit has been received. The rate shall be at the average Chartered Bank Prime Rate as published on the Bank of Canada Web site, less 2%. The interest rate shall be updated by Toronto Hydro at a minimum on a quarterly basis. The interest will be calculated and applied to the existing deposit prior to each update and at a minimum on a yearly basis.

Toronto Hydro will undertake an annual review of all security deposit requirements for each Consumer or Customer based on the ***Good Payment History*** described in this document.

- Where it is determined that all or part of the deposit is no longer required, the account will be credited with the amount of the deposit plus accumulated interest.

- Where it is determined that a deposit is now required or needs to be adjusted upward, the amount of the deposit will be added to the next regular bill and is payable by the due date of that bill. As with all outstanding balances payment arrangements that are satisfactory to Toronto Hydro may be made.

- For Consumers or Customers in the >5000 kW demand rate class, where the Consumer or Customer is in a position to have some or all of the deposit refunded, only 50% of the deposit will be returned. A higher refund requires a credit rating from a recognized credit rating agency based on the criteria previously stated.

  Note: Where no deposit is on file or there is a deposit that does not meet

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

the maximum amount, and the Consumer or Customer meets the good payment history criteria but does not meet the time frame, a new or increased deposit amount will not be added.

Upon closure of the Consumer's or Customer's account with Toronto Hydro, including a Consumer or Customer move from standard supply service ("SSS") to a competitive retailer where the retailer is performing the billing function (retailer consolidated billing), for all accounts types, the balance of the security deposit plus accumulated interest, after all amounts owing are paid, will be returned to the Consumer or Customer within six weeks of the closure of the account.

No earlier than 12 months after the payment of a security deposit or the making of a prior demand for a review, a Consumer or Customer may request in writing that the deposit amount be reviewed to determine whether the entire amount of the security deposit, or some portion of it, should be returned to the Consumer or Customer as it is no longer required.

2.4.4 Billing

This section should outline the billing methods and billing cycles the Distributor has established to provide a Customer with Distribution Services, supply through Standard Service Supply or through a Retailer, per the rules and regulations laid out in the Retail Settlement Code.

Toronto Hydro may, at its option, render bills to its Customers on either a monthly, every two months, quarterly or annual basis. Bills for the use of electrical energy may be based on either a metered rate or a flat rate, as determined by Toronto Hydro.

A Customer may elect aggregated billing for multiple services provided all of the following conditions are met:

- the premises and businesses are situated on one contiguous parcel of land i.e. not separated by public roadway
- all premises are under one ownership
- the services are supplied at the same voltage
- the meters are of the interval type, allowing logical totalization of the coincident demands. If interval meters are not already in place, the Customer will install the necessary equipment, at the Customer's own cost, to Toronto Hydro specifications.

The Customer may dispute charges shown on the Customer's bill or other matters by contacting and advising Toronto Hydro of the reason for the dispute. Toronto Hydro will promptly investigate all disputes and advise the Customer of the results.

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

2.4.5 Payments and Overdue Account Interest Charges

This section should outline payment methods that the Distributor has established to provide the Customer with Distribution Services, supply through Standard Service Supply or through a Retailer as per the rules and regulations laid out in the Retail Settlements Code.

Bills are rendered for energy services provided to the Consumer. Bills are payable in full by the due date; otherwise, overdue interest charge will apply. Where a partial payment has been made by the Consumer on or before the due date, the interest charge will apply only to the amount of the bill outstanding at the due date. In the event of partial payment by a Customer, payments shall be allocated by the portions of the bill covering competitive and non-competitive electricity costs based on the ratios of the amount billed for competitive and non-competitive costs.
Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

Toronto Hydro shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service, except for physical damage to facilities arising directly from Toronto Hydro's entry on the property. A reconnection charge will apply where the service has been disconnected due to non-payment.
The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.
Customers will be required to pay special charges, on request, which may arise from a variety of conditions such as:

Transfer Charge. A change of occupancy charge will apply to all accounts taken over by a new Consumer.

Collection Charge. It is sometimes necessary, for the Customer's convenience, for a Toronto Hydro employee to visit a Consumer's premises to collect payment for an account. There will be a charge for this service.

Reconnection Charge. A Consumer or Customer disconnected for non-payment shall be required to pay a reconnection fee.

2.5 Customer Information

The Conditions of Service shall describe the provision of information with respect to chapter 11 of the Retail Settlement Code. This specifies the rights of Consumers and retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information. The Conditions of Service should include reference to include information subject to privacy regulations and load profile information.

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

Any processes for handling requests for information outside of the requirements of the Retail Settlement Code should be described in this section.

A third party who is not a retailer may request historical usage information with the written authorization of the Consumer to provide their historical usage information.

Toronto Hydro will provide information appropriate for operational purposes that has been aggregated sufficiently, such that an individual's Consumer information cannot reasonably be identified, at no charge to another distributor, a transmitter, the IESO or the OEB. Toronto Hydro may charge a fee that has been approved by the OEB for all other requests for aggregated information.

At the request of a Consumer, Toronto Hydro will provide a list of retailers who have Service Agreements in effect within its distribution service area. The list will inform the Consumer that an alternative retailer does not have to be chosen in order to ensure that the Consumer receives electricity and the terms of service that are available under Standard Supply Service.

Upon receiving an inquiry from a Consumer connected to its distribution system, Toronto Hydro will either respond to the inquiry if it deals with its own distribution services or provide the Consumer with contact information for the entity responsible for the item of inquiry, in accordance with chapter 7 of the Retail Settlement Code.

An embedded distributor that receives electricity from Toronto Hydro shall provide load forecasts or any other information related to the embedded distributor's system load to Toronto Hydro, as determined and required by Toronto Hydro. A distributor shall not require any information from another distributor unless it is required for the safe and reliable operation of either distributor's distribution system or to meet a distributor's licence obligations.

Section 3 – CUSTOMER CLASS SPECIFIC

3 CUSTOMER CLASS SPECIFIC

The Customer Class Specific section shall contain references to services and requirements, which are specific to individual Customer classes. This section should cover such items as:

- ***Demarcation Point***
- ***Metering.***
- ***Service Entrance Requirements.***
- ***Delineation of Ownership and Operational Points of Demarcation.***
- ***Special Contracts.***
- ***Other conditions specific to Customer class.***

The following are examples of Customer specific subsections. It is recognized that Customer Classifications are unique to each Distributor. The Distributor is not limited by these examples to the range and scope of their Customer Classifications. Each Distributor therefore should review their current Classifications and ensure that all of their existing Customer Classifications are adequately covered by the Distributor' s Conditions of Service document.

3.1 Residential

Include all items that apply specifically to Residential Customers not covered under the General section.

Refer to Tables 1.1, 1.2 and 1.3 and Table 2 under Section 5 of this Conditions for Point of Demarcation, Standard Allowance and Connection Fees for Residential Services.

3.1.1 Overhead Services

3.1.1.1 Minimum Requirements

In addition to the requirements of the Ontario Electrical Safety Code (latest edition), the following conditions shall apply:

(i) A clevis type insulator is to be supplied and installed by the Customer.

(ii) This point of attachment device must be located:

(a) Not less than 4.5 metres (15 feet) nor greater than 5.5 metres (18 feet) above grade (to facilitate proper ladder handling techniques). Building must have a minimum offset from property line of 1.2 metres (4 feet).

(b) Between 150 millimetres and 300 millimetres (6-12 inches) below the service head.

(c) Within 914 millimetres (3 feet) of the face of the building.

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(iii) Clearance must be provided between utility conductors and finished grade of at least 6 metres (19 feet) over traveled portions of the road allowance and 4.5 metres (15 feet) over all other areas.

A minimum horizontal clearance of 1.0 metres (39 inches) must be provided from utility conductors and any second storey windows.

(iv) A large, 4 jaw meter socket of an approved manufacturer shall be provided. Certain areas will require a 5-jaw socket as determined by Toronto Hydro. The Customer should contact Toronto Hydro to confirm details.

(v) Clear unobstructed access must be maintained to and in front of the meter location.

(vi) Service locations requiring access to adjacent properties (mutual drives, narrow side set-backs, etc.) will require the completion of an easement or written consent from the property owner(s) involved.

(vii) The approved meter base shall be mounted directly below the service mast such that the midpoint of the meter is 1.73 m (± 100 mm) above finished grade within 914 mm of the face of the building (in front of any existing or proposed fence), unless otherwise approved by Toronto Hydro.

3.1.1.2 Services Over Swimming Pools

Although the Ontario Electrical Safety Code allows electrical conductors to be located at adequate height, Toronto Hydro will **not** allow electrical conductors to be located above swimming pools.

Where a new swimming pool is to be installed it will be necessary to relocate, at the property owner's expense, any electrical conductors located directly over the proposed pool location.

Where overhead service conductors are in place over an existing swimming pool, Toronto Hydro will provide up to 30 metres of overhead service conductors, at no charge, to allow rerouting of the service. The property owner will pay any other costs.

3.1.2 Underground Services for Individual Residences

Customers requesting an underground service in an overhead area will be required to pay 100% connection costs for the underground service less the Standard Allowance for an overhead service.

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The owner shall pay for any necessary road crossings.

The trench route must be approved by Toronto Hydro and is to follow the route indicated on the underground drawing supplied by Toronto Hydro. Any deviation from this route must be approved by Toronto Hydro. The Customer will be responsible for Toronto Hydro's costs associated with re-design and inspection services due to changes or deviations initiated by the Customer or its agents.

The owner will assure the provision for the service entrance and meter meets Toronto Hydro approval.

Where there are other services to be installed (e.g. gas, telephone, and cable) these shall be coordinated to avoid conflict with Toronto Hydro's underground cables. Toronto Hydro's installation will not normally commence until all other servicing and grading have been completed.

It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies (including Toronto Hydro) before digging.

It is the responsibility of the owner to contact Toronto Hydro to inspect each trench prior to the installation of Toronto Hydro's service cables.

The owner shall provide unimpeded access for Toronto Hydro to install the service.

The owner shall ensure that any intended tree planting has appropriate clearance from underground electrical plant.

3.2 General Service

Include all items that apply specifically to general service Customers not covered under the other sections, and broken down (by load demand).

a) The Customer shall supply the following to Toronto Hydro well in advance of installation commencement:

- Required in-service date
- Proposed Service Entrance equipment's Rated Capacity (Amperes) and Voltage rating and metering requirements
- Propose Total Load details in kVA and/or kW (Winter and Summer)
- Locations of other services, gas, telephone, water and cable TV.
- Details respecting heating equipment, air-conditioners, motor starting current limitation and any appliances which demand a high consumption of electricity

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- Survey plan and site plan indicating the proposed location of the service entrance equipment with respect to public rights-of-way and lot lines.
- For General Service (50 – 999kW and 1000kW and above) Class Customers, electrical, architectural and/or mechanical drawings as required by Toronto Hydro.

b) The Customer shall construct and install all civil infrastructure (including but not limited to poles, UG conduits, cable chambers, cable pull rooms, transformer room/vault/pad) on private property, that is deemed required by Toronto Hydro as part of its connection assets. All such civil infrastructures are to be in accordance with Toronto Hydro's current standards, practices, specifications and this Conditions and are subject to Toronto Hydro's inspection and acceptance.

Should the Customer construct and install the civil infrastructure related to connection assets, Toronto Hydro shall not include the associated civil component in its calculation of Basic and Variable Connection Fees.

c) Alternatively, the Customer may have Toronto Hydro construct and install the civil infrastructure that forms part of Toronto Hydro's connection assets on private property and the Customer will therefore be responsible for all costs via Basic Connection and Variable connection Fees (as applicable).

d) Toronto Hydro is responsible for the maintenance and repairs of its connection assets **but not** the transformer room(s) or any other civil structure that is part of the Customer's building.

e) When effecting changes the Customer shall maintain sufficient clearances between electrical equipment and buildings and other permanent structures to meet the requirements of the Ontario Electrical Safety Code and the Occupational Health & Safety Act and Regulations.

f) It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies (including Toronto Hydro) before digging.

g) Provided the existing civil infrastructure has been maintained in satisfactory conditions by the Customer, Toronto Hydro will undertake the necessary programs to enhance its distribution plant at its expense, as part of its planned activities during normal business hours, Monday to Friday.

When a Customer requests that such planned activities be done outside Toronto Hydro's normal business hours, then the Customer shall pay the incremental costs incurred by Toronto Hydro as a result thereof. A Customer contribution may not be required for work performed outside of normal business hours if the

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work is part of planned maintenance programs on Toronto Hydro distribution system.

In the event that services or facilities to a Customer need to be restored as a result of these construction or maintenance activities by Toronto Hydro, they will be restored to an equivalent condition.

In addition, Toronto Hydro will carry out the necessary construction and electrical work to maintain existing supplies by providing standard overhead or underground supply services to Customers affected by Toronto Hydro's construction activities. If a Customer requests special construction beyond the normal Toronto Hydro standard installation in accordance with the program, the Customer shall pay the additional cost associated therewith, including engineering and administration fees.

h) Toronto Hydro shall install, maintain, and replace, at its own cost, all those civil infrastructures that are part of its main distribution system (i.e. not including connection assets) that may be located on private property and which serve Customers that are located outside of that private property. These Toronto Hydro civil infrastructures will require an easement.

i) The Customer shall install, maintain, and replace, at its own cost, all those civil infrastructures located on private property that are required to house the connection assets (i.e. the electrical equipment owned by Toronto Hydro) that serve Customers that are located on that private property.

Where changes to Customer's civil infrastructure are part of a Toronto Hydro initiated enhancement project, Toronto Hydro may absorb the costs of modifications to the Customer's civil infrastructure, provided the existing civil infrastructure has been maintained in satisfactory condition by the Customer.

j) The Customer shall maintain in proper working conditions all Customer-owned service disconnecting devices (such as main switch and secondary breakers) that Toronto Hydro may need to operate for safety of its operations. Toronto Hydro shall not be liable if a switch / breaker were become inoperative or get damaged during its operation.

Refer to Tables 1.1, 1.2 and 1.3 and Table 2 of Section 5 of this Conditions for Point of Demarcation, Standard Allowance and Connection Fees for General Service.

Section 3 – CUSTOMER CLASS SPECIFIC

3.2.1 Electrical Requirements (as applicable)

For low voltage supply, the Customer's service entrance equipment shall be suitable to accept conductors installed by Toronto Hydro. The Customer's cables shall be brought to a point determined by Toronto Hydro for connection to Toronto Hydro's supply.

The owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the Ontario Electrical Safety Code.

In order to allow for an increase in load, the owner shall provide spare wall space so that at least 30% of the Customers supplied through meter sockets can accommodate meter cabinets at a later date.

Access doors, panels, slabs and vents shall be kept free from obstructing objects. The Customer will provide unimpeded and safe access to Toronto Hydro at all times for the purpose of installing, removing, maintaining, operating or changing transformers and associated equipment.

The electrical room must be located to provide safe access from the outside or main hallway, and not from an adjoining room, so that it is readily accessible to Toronto Hydro's employees and agents at all hours to permit meter reading and to maintain electric supply. This room must be locked. The owner shall install a pad bolt with mortise strike (Ackland Hardware, Cat. No. 199-10 or equivalent). Toronto Hydro shall provide a secure arrangement so that Toronto Hydro's padlock can be installed as well as the Customer's lock.

The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code and shall be located indoors.

Outside doors providing access to electrical rooms must have at least 150-mm clearance between final grade and the bottom of the door. Electrical rooms 'on' or 'below' grade must have a drain including a "P" trap complete with a non-mechanical priming device and a backwater valve connected to the sanitary sewer. The electrical room floor must slope 6-mm/300 mm or 2% towards the drain.

The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault

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circuit shall be supplied from a panel located and clearly identified in the electrical room.

3.2.2 Underground Service Requirements

The Customer shall construct or install all civil infrastructure (including but not limited to poles, UG conduits, cable chambers, cable pull rooms, transformer room/vault/pad) on private property, that is deemed required by Toronto Hydro as part of its Connection Assets. All civil infrastructures are to be in accordance with Toronto Hydro's current standards, practices, specifications and this Conditions and are subject to Toronto Hydro's inspection/acceptance.

The Customer is responsible to maintain all its structural and mechanical facilities on private property in a safe condition satisfactory to Toronto Hydro.

The trench route must be approved by Toronto Hydro. Any deviation from this route must also be approved by Toronto Hydro. The Customer will be responsible for Toronto Hydro's costs associated with re-design and inspection services due to changes or deviations initiated by the Customer or its agents or any other body having jurisdiction.

It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies (including Toronto Hydro) before digging.

It is the responsibility of the owner to contact Toronto Hydro to inspect each trench prior to the installation of Toronto Hydro's cables.

3.2.3 Temporary Services (other than Residential)

A temporary service is a normally metered service provided for construction purposes or special events. Temporary services can be supplied overhead or underground. The Customer will be responsible for all associated costs for **the installation and removal** of equipment required for a temporary service to Toronto Hydro's point of supply. Temporary services may be provided for a period of no more than 12 months. Temporary services must be renewed thereafter if an extension is required and the equipment for such temporary service must be reinspected at the end of the 12-month period.

Subject to the requirements of Toronto Hydro, supply will be connected after receipt of a 'Connection Authorization' from the Electrical Safety Authority, a signed contract and a deposit from the Customer.

Where meter bases are required, they must be approved by Toronto Hydro and shall be securely mounted on minimum 152 mm diameter poles (or alternative if

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approved by Toronto Hydro) so that the midpoint of the meter is 1.73 m (± 100 mm) from finished grade.

In the case of temporary overhead services, the Customer shall leave 760 mm of cable at the masthead for connection purposes.

In the case of temporary underground services, the Customer's cable shall extend to Toronto Hydro's point of supply.

3.3 General Service (Above 50 kW)

Include all items that apply specifically to General Service Customers (above 50 kW) not covered under the General section. Describe the criteria to determine how a Customer is classified as being above 50 kW.

All non-residential Customers with an average peak demand between 50 kW and 999 kW over the past twelve months are to be classified as General Services above 50 kW.

3.3.1 New Residential Subdivisions or Multi-Unit Developments

Customers of new Residential Subdivisions involving the construction of new city streets and roadways, or of Multi-unit Developments that are supplied from primary distribution systems built along private streets, are treated as Non-Residential Class Customers and will be subject to capital contribution for "expansion" work, in addition to any applicable Connection Fees. Should the Economic Evaluation identify a shortfall for the Expansion, the Developer has a choice of either completing the portion of plant not yet connected to Toronto Hydro's system or have Toronto Hydro complete this work in accordance with Section 3.3 of the DSC Code, titled "Alternative Bids". The Customer will not be allowed to complete construction work on Toronto Hydro's existing distribution system.

All other Residential Subdivisions or Multi-unit complexes will follow the general terms and conditions for Connection Fees and capital contribution for the appropriate General Class Customers.

In all cases, all of the electrical service must be constructed to Toronto Hydro's standards and in compliance with the Ontario Electrical Safety Code, applicable laws, regulations and codes.

The Developer is required to enter into a Supply Agreement with Toronto Hydro and to pay Toronto Hydro the deposit(s) for ordering of equipment and associated design and construction work for the installation of the proposed underground electrical distribution system. This amount will be paid concurrently with the signing of the Supply Agreement.

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In case of conflict between the Supply Agreement and the terms herein, the Supply Agreement shall be binding. All design work including service locations and trench routes must be approved by Toronto Hydro.

3.3.2 Electrical Requirements

Where the size of the Customer's electrical service warrants, as determined by Toronto Hydro, the Customer will be required to provide facilities on its property and an easement as required (i.e. on the premises to be served), acceptable to Toronto Hydro, to house the necessary transformer(s) and/or switching equipment. Toronto Hydro will provide planning details upon application for service.

Toronto Hydro will supply, install and maintain the electrical transformation equipment within the transformer vault or pad supplied by the Customer, at its expense, on the property. Toronto Hydro has the right to have this equipment connected to its distribution system.

The owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the Ontario Electrical Safety Code.
In order to allow for an increase in load, the owner shall provide spare wall space so that at least 30% of the Customers supplied through meter sockets can accommodate meter cabinets at a later date.

The electrical room must be separate from, but adjacent to, the transformer vault. It must be located to provide safe access from the outside or main hallway, and not from an adjoining room, so that it is readily accessible to Toronto Hydro’s employees and agents at all hours to permit meter reading and to maintain electric supply. This room must be locked. The owner shall install a pad bolt with mortise strike (Ackland Hardware, Cat. No. 199-10 or equivalent). Toronto Hydro shall provide a secure arrangement so that Toronto Hydro’s padlock can be installed as well as the Customer's lock.

The electrical room shall not be used for storage or contain equipment not related to the electrical installation within the area designated by Toronto Hydro as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code, and shall be located indoors.
Outside doors providing access to electrical rooms must have at least 150-mm clearance between final grade and the bottom of the door. Electrical rooms 'on' or 'below' grade must have a drain including a "P" trap complete with a non-mechanical priming device and a backwater valve connected to the sanitary

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sewer. The electrical room floor must slope 6-mm/300 mm or 2% towards the drain.

The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault circuit shall be supplied from a panel located and clearly identified in the electrical room.

The owner shall identify each tenant's metered service by address and/or unit number in a permanent and legible manner. The identification shall apply to all main switches, breakers and to all meter cabinets or meter mounting devices that are not immediately adjacent to the switch or breaker. The electrical room shall be visibly identified from the outside.

3.3.3 Technical Information

Where project drawings are required for Toronto Hydro's approval, for items under Toronto Hydro's jurisdiction, the Customer or its authorized representative must ensure that proposal drawings are fully in compliance with Toronto Hydro's standards. Approval of project drawings by Toronto Hydro shall not relieve the Customer of its responsibility in respect of full compliance with Toronto Hydro's standards and all applicable laws, regulations and codes. In all cases, one copy of all relevant drawings must be submitted to Toronto Hydro. Where the Customer requires an approved copy to be returned, two copies of all plans must be submitted.

Prior to the preparation of a design for a service, the Customer will provide the following information to Toronto Hydro as well as the approximate date that the Customer requires the electrical service and the due date that Toronto Hydro's civil construction drawings are required in order to co-ordinate with site construction.

3.3.3.1 Site & Grading Plans

Indicate the lot number, plan numbers and, when available, the street number. The site plan shall show the location of the Building on the property relative to the property lines, any driveways and parking areas and the distance to the nearest intersection. All elevations shall be shown for all structures and proposed installations.

3.3.3.2 Mechanical Servicing Plan

Show the location on the property of all services proposed and/or existing such as water, gas, storm and sanitary sewers, telephone, et cetera.

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3.3.3.3 Floor Plan

Show the service location, other services location, driveway, parking and indicate the total gross floor area of the building.

3.3.3.4 Duct Bank Location

Show the preferred routing of the underground duct bank on the property. This is subject to approval by Toronto Hydro.

3.3.3.5 Transformer Location

Indicate the preferred location on the property for the high voltage transformation. This is subject to approval by Toronto Hydro. Transformation will be vault, pad, submersible type or polemounted depending on the project load requirements.

3.3.3.6 Electrical Meter Room

Indicate preferred location in the building of the meter room and the main switchboard.

3.3.3.7 Single Line Diagram

Show the main service entrance switch capacity, the required supply voltage, and the number and capacity of all sub-services showing provision for metering facilities, as well as the connected load breakdown for lighting, heating, ventilation, air conditioning et cetera. Also, indicate the estimated initial kilowatt demand and ultimate maximum demands. Provide protection equipment information where coordination is required between Toronto Hydro and Customer owned equipment. Fusing will be determined later by Toronto Hydro to co-ordinate with the transformer size selected.

3.3.3.8 Switchgear

Submit three copies of any service entrance switchgear to be installed for Toronto Hydro's approval, including interlocking arrangement if required.

3.3.3.9 Substation Information

Where a Customer owned substation is to be provided, the owner will be required to provide the following in addition to the site information outlined above.

- All details of the transformer, including kVA capacity, short circuit rating (in accordance with 3.3.4.1), primary and secondary voltages, impedance and cooling details.
- A site plan of the transformer station showing the equipment layout, proposed primary connections, grounding and fence details, where applicable.
- A coordination study for protection review.

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3.3.4 Technical Considerations

3.3.4.1 Short Circuit Ratings

16000/27600 V Supply: The Customer's protective equipment shall have a three phase, short circuit rating of 800 MVA symmetrical. The asymmetrical current is 27,000 A (1.6 factor used).

8000/13800 V Supply: The Customer's protective equipment shall have a three phase, short circuit rating of 500 MVA symmetrical. The asymmetrical current is 34,000 A (1.6 factor used.)

2400/4160 V Supply: The Customer's protective equipment shall have a three phase, short circuit rating of 250 MVA symmetrical or 56,000 A asymmetrical (1.6 factor used).

600/347 V Supply: The Customer's protective equipment shall have a minimum short circuit rating of 50,000 A.

208/120 V Supply: Available short circuit current may be obtained upon request to Toronto Hydro.

3.3.4.2 Primary Fusing

All equipment connected to the Toronto Hydro's distribution system shall satisfy the short circuit ratings specified in clause 3.3.4.1.
The Customer and/or the Customer's consultant shall specify the fuse link rating and demonstrate coordination with Toronto Hydro's upstream protection including station breakers and/or distribution fuses. The Customer shall submit, at its expense, a coordination study to Toronto Hydro for verification to ensure coordination with upstream protection including station breakers and/or distribution fuses. The Customer shall maintain an adequate supply of spare fuses to ensure availability for replacement in the event of a fuse blowing.

3.3.4.3 Ground Fault Interrupting

Where ground fault protection is required to comply with the Ontario Electrical Safety Code, the method and equipment used shall be compatible with Toronto Hydro's practice of grounding transformer neutral terminals in vaults. Zero sequence sensing will normally apply. Where ground strap sensing is used, the ground sensing devices shall be set to operate at 600 A if transformer and switchboard buses are not bonded and 400 A if buses are bonded. Ground fault protection proposals for dual secondary supply arrangements shall be submitted to Toronto Hydro for approval, before construction of the switchboard.

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3.3.4.4 Lightning Arresters

Customer installations that are directly supplied from Toronto Hydro's primary underground system are not protected with lightning arresters. If the Customer wishes to install lightning arresters they shall be located on the load side of the first protective devices. For Customer installations that are supplied from Toronto Hydro's primary overhead system, Toronto Hydro, at its expense, will install lightning arresters at the pole and the Customer, at its expense, may install lightning arresters in the switchgear on the load side of the incoming disconnect device. The mimic diagram shall indicate the presence of such devices in the switchgear.

3.3.4.5 Basic Impulse Level (B.I.L.)

The Customer's apparatus shall have a minimum Basic Impulse Level in accordance with the following:

(a) 2400/4160 supply voltage - 60 kV B.I.L.
(b) 8000/13800 " " - 95 kV B.I.L
(c) 16000/27600 " " - Delta primary150 kV B.I.L.
(d) 16000/27000 " " - Grounded Wye primary 125 kV B.I.L.

3.3.4.6 Unbalanced Loads

On three-phase service, the unbalance due to single-phase loads shall not exceed 20% of the Customer's balanced phase loading expressed in kilowatts.

3.4 General Service (Above 1000 kW)

Include all items that apply specifically to General Service Customers (above 1000 kW) not covered under the General section. Describe the criteria to determine how a Customer is classified as being above 1000 kW.

All non-residential Customers with an average monthly demand of 1000 kW or higher, averaged over twelve consecutive months, as determined by Toronto Hydro, are to be classified as Customers over 1000 kW.

3.4.1 Electrical Requirements

Where a primary service is provided to a Customer-owned substation, the Customer shall install and maintain such equipment in accordance with all applicable laws, codes, regulations, and Toronto Hydro's Customer Owned Substation requirements for high voltage installations. Toronto Hydro will provide planning details upon application for service.

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Customer owned substations are a collection of transformers and switchgear located in a suitable room or enclosure owned and maintained by the Customer, and supplied at primary voltage: i.e. the Supply Voltage is greater than 750 volts.

All high voltage distribution services are three-phase, four-wire. The Customer is required to bring out a neutral conductor for connection to the system neutral. If not required for Customer's use, this neutral shall be terminated to the Customer's station ground system.
Toronto Hydro will provide Customer interface details and requirements for high voltage supplies.

It is recommended that Customers' transformers have voltage taps in their primary windings as shown in Table 4 in Section 5 of this Conditions. Transformers other than listed in Table 4 may be suitable but shall not be connected without the specific written approval of Toronto Hydro.

Customer owned substations must be inspected by both the Electrical Safety Authority and Toronto Hydro. The owner will provide a pre-service inspection report to Toronto Hydro. A contractor acceptable to Toronto Hydro will prepare the certified report to Toronto Hydro.

The Customer and Toronto Hydro shall inspect their own respective substations in accordance with the Distribution System Code. The minimum inspection cycles for Customer specific substations are one year for open substations and three years for enclosed substations. To facilitate and encourage the maintenance of this equipment, including, without limitation, the installation, maintenance, and testing of vault fire alarm detectors, Toronto Hydro will provide one power interruption annually, at no charge. This no-charge service would be scheduled during Toronto Hydro's normal business hours, Monday to Friday, and appointment times are not necessarily guaranteed. Toronto Hydro will charge Customers for power interruptions arranged at times other than as outlined above.

3.4.2 Technical Information and Considerations

The same information and considerations apply as for other General Service Customers. Refer to Subsection 3.3.3 and 3.3.4 for applicable requirements.

3.5 Embedded Generation Facilities

This section should include all terms and conditions applicable to the connection of embedded generation facility to the distributor (e.g., application process, engineering standards and operating agreements).

The Generator Classifications set forth in the Distribution System Code are outlined in the table below:

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Generator Classification	Rating
Micro	≤ 10 kW, for customer's own use
Small	(a) ≤ 500 kW connected on distribution system voltage < 15 kV (b) ≤ 1 MW connected on distribution system voltage ≥ 15 kV
Mid-Sized	(a) > 500 kW but ≤ 10 MW connected on distribution system voltage < 15 kV (b) > 1 MW but ≤ 10 MW connected on distribution system voltage ≥15 kV
Large	> 10 MW

3.5.1 Connection Agreement

Section 3.5 does not apply to the connection or operation of an emergency backup generation facility or an embedded generation facility that is used exclusively for load displacement purposes. Refer to Subsection 2.3.6 for applicable requirements.

Toronto Hydro shall enter into a Connection Agreement with all existing Customers who have an embedded generation facility connected to the Toronto Hydro distribution system and also with all new Customers prior to connecting a new generation facility. For micro-embedded generation facility, the Connection Agreement shall be in the form set out in Schedule B1 in Section 6 and for small, mid-sized, and large embedded generation facilities, the Connection Agreement shall be in the form set out in Schedule B2 in Section 6. Where Toronto Hydro does not have a Connection Agreement with an existing Customer that has a generation facility connected to the Toronto Hydro distribution system, the Customer shall be deemed to have accepted and agreed to be bound by all of the Connection Agreement Terms and Conditions attached to this Conditions as Schedule B3 in Section 6, and the terms of any operating schedule delivered to it from time to time by Toronto Hydro.

3.5.2 Connection Process

Toronto Hydro has created an "Embedded Generation Connection Overview" which contains the following information:

(a) the process for having a generation facility connected to the Toronto Hydro distribution system, including any form necessary for the application;

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(b) information regarding any approvals from the ESA, the IESO, OEB, OPA, or a transmitter that are required before Toronto Hydro will connect a generation facility to its distribution system;

(c) the technical requirements for being connected to the Toronto Hydro distribution system including the metering requirements; and

(d) the standard contractual terms and conditions for being connected to the Toronto Hydro distribution system.

Subject to all applicable laws, Toronto Hydro will make all reasonable efforts in accordance with the provisions of Section 3.5 to promptly connect to its distribution system a generation facility, which is the subject of an application for connection.

3.5.3 Connection of Micro-Generation Facilities

A person who wishes to connect a micro-embedded generation facility to the Toronto Hydro distribution system shall submit an application to Toronto Hydro providing the following information:

(a) the name-plate rated capacity of each unit of the proposed generation facility and the total name-plate rated capacity of the proposed generation facility at the connection point;
(b) the fuel type of the proposed generation facility;
(c) the type of technology to be used; and
(d) the location of the proposed generation facility including address and account number where available.

Where the proposed micro-embedded generation facility is located at an existing Customer connection, Toronto Hydro shall, within 15 days of receiving the application, make an offer to connect or provide reasons for refusing to connect the proposed generation facility. Toronto Hydro shall give the applicant at least 30 days to accept the offer to connect and shall not revoke the offer to connect until this time period has expired. Toronto Hydro will not charge the Customer for the preparation of the Offer to Connect.

Toronto Hydro shall make any necessary metering changes and connect the applicant's micro-embedded generation facility to its distribution system within 5 days of the applicant completing the following:

(a) Provide Toronto Hydro with a copy of the authorization to connect from the ESA;
(b) enter into a Connection Agreement with Toronto Hydro in the form set out in Section 6, Reference #2 Schedule B1; and
(c) pay Toronto Hydro for the costs of any necessary metering changes.

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3.5.4 Connection of Other Generation Facilities

Subsection 3.5.4 applies to the connection to the Toronto Hydro distribution system of an embedded generation facility, which is not a micro-embedded generation facility.

After a person who is considering applying for the connection of a generation facility to the Toronto Hydro distribution system has requested a preliminary meeting with Toronto Hydro and has provided the required initial set of information, then Toronto Hydro shall provide a time when its relevant employees are available to meet with the person within 15 days of the person requesting the meeting. For the purposes of this section, the following is the required "initial set of information":

(a) the nameplate rated capacity of each unit of the proposed generation facility and the total nameplate rated capacity of the generation facility at the connection point;

(b) the fuel type of the proposed generation facility;

(c) the type of technology to be used; and

(d) the location of the proposed generation facility including address and account number with the distributor where available.

At the preliminary meeting, Toronto Hydro shall discuss the basic feasibility of the proposed connection including discussing the location of its existing distribution facilities in relation to the proposed generation facility and providing an estimate of the time and costs necessary to complete the connection. Toronto Hydro will not charge for its preparation for and attendance at the preliminary meeting.

A person who wishes to apply for the connection of a generation facility to the Toronto Hydro distribution system shall submit an application, pay their impact assessment costs (applicable to mid-sized and large generation facilities or small generation facilities where requested by Toronto Hydro) and provide the following information:

(a) any of the "initial set of information" which has not yet been provided to Toronto Hydro;

(b) a single line diagram of the proposed connection; and

(c) a preliminary design of the proposed interface protection.

For a **small** embedded generation facility, where Toronto Hydro believes that a system directly connected to its distribution system may be impacted by the proposed small embedded generation facility, Toronto Hydro will advise the Customer of the costs to conduct any required impact assessment.

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Toronto Hydro shall provide the Customer with its results of its impact assessment of the proposed generation facility, a detailed cost estimate of the proposed connection, and an offer to connect within:

(a) 60 days of the receipt of the application where no distribution system reinforcement or expansion is required; and
(b) 90 days of the receipt of the application where a distribution system reinforcement or expansion is required.

For a **mid-sized** embedded generation facility, Toronto Hydro shall provide the Customer with its impact assessment of the proposed generation facility within 60 days of the receipt of the application

For a **large** embedded generation facility, Toronto Hydro shall provide the Customer with its impact assessment of the proposed generation facility within 90 days of the receipt of the application.

The impact assessment shall set out the impact of the proposed generation facility on the Toronto Hydro distribution system and any of its customers including:

(a) any voltage impacts, impacts on current loading settings and impacts on fault currents;
(b) the connection feasibility;
(c) the need for any line or equipment upgrades;
(d) the need for transmission system protection modifications; and
(e) any metering requirements.

The Customer shall submit any material revisions to the design, planned equipment or plans for the proposed generation facility and connection with Toronto Hydro. Toronto Hydro shall then prepare a new impact assessment within the relevant time period as set out above.

In the case of an application for the connection of a mid-sized or large embedded generation facility, after receiving from Toronto Hydro the impact assessment the applicant shall pay to Toronto Hydro for the cost of preparing a detailed cost estimate of the proposed connection and enter into an agreement with Toronto Hydro on the scope of the project. Toronto Hydro shall then provide the applicant with a detailed cost estimate and an offer to connect by the later of 90 days after the receipt of payment from the applicant and 30 days after the receipt of comments from a transmitter or other distributor that may have been advised under the following clause.

Within 10 days of receiving payment from the applicant for preparing a detailed cost estimate, Toronto Hydro shall advise any transmitter or distributor whose transmission or distribution system is directly connected to the Toronto Hydro

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distribution system that it is preparing a detailed cost estimate for a proposed large or mid-sized embedded generation facility. Toronto Hydro will use its discretion in advising impacted transmitter or distributor when the detailed cost estimate involves a proposed small embedded generation facility.

After the applicant has entered into a connection cost agreement with Toronto Hydro and has provided the detailed engineering drawings with respect to the proposal, Toronto Hydro shall conduct a design review to determine if the detailed engineering plans are acceptable.

Toronto Hydro has the right to witness the commissioning and testing of the connection of the generation facility to its distribution system. After the applicant has

(a) informed Toronto Hydro that it has received all necessary approvals;
(b) provided Toronto Hydro with a copy of the Certificate of Inspection from the ESA; and
(c) entered into the appropriate Connection Agreement;

and Toronto Hydro has received the Authorization to Connect from ESA it shall act to connect the generation facility to its distribution system in accordance with this Conditions.

Subject to any delays in commissioning and testing of the generation facility, which may be beyond the control of Toronto Hydro, Toronto Hydro shall connect a proposed small embedded generation facility within:

a) 60 days of the applicant taking the steps set out above, where no distribution system reinforcement or expansion is required; and
(b) 180 days of the applicant taking the steps set out above, where a distribution system reinforcement or expansion is required.

Information on the process for connecting a generation facility to a distribution system is set out in Appendix F.1 of the DSC.

3.5.5 Technical Requirements

The Customer shall ensure that the connection of its generation facility to the distribution system does not materially adversely affect the safety, reliability and efficiency of the Toronto Hydro distribution system. New or significantly modified generation facilities shall meet the technical requirements specified in Appendix F.2 of the DSC. In addition, the Customer shall also comply with the detailed requirements outlined in Section 6, Reference #3 - "Toronto Hydro Parallel Generation Requirements".

The Customer with an embedded generation facility connected to the Toronto Hydro distribution system (other than a micro-embedded generation facility)

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shall reimburse Toronto Hydro for any damage to the distribution system or increased operating costs that may result from the connection of a generation facility.

A Customer with a generation facility connected to the Toronto Hydro distribution system shall include in the connection agreement and upon request by Toronto Hydro provide satisfactory evidence of a regular, scheduled maintenance plan that ensures that the generator's connection devices, protection systems and control systems are maintained in good working conditions.

All equipment that is connected, operated, procured or ordered before May 1, 2002 is deemed to be in compliance with the technical requirements of the DSC.

Toronto Hydro may determine that equipment that was deemed to be in compliance with the technical requirements of the DSC as noted in the immediately preceding paragraph is not in **actual** compliance with the technical requirements due to any of the following conditions:

(a) a material deterioration of the reliability of the distribution system resulting from the performance of the generator's equipment; or
(b) a material negative impact on the quality of power of an existing or a new customer resulting from the performance of the generator's equipment; or
(c) a material increase in generator capacity at the site where the equipment deemed compliant is located.

In such a case, Toronto Hydro will provide the Customer with rules and procedures for requiring such equipment to be brought into actual compliance. The Customer shall then bring its equipment into actual compliance with the technical requirements and within a reasonable time period specified by Toronto Hydro.

When a Customer with an embedded generation facility is connected to the Toronto Hydro distribution system, the Customer shall provide an interface protection that is capable of automatically isolating the generation facility from the Toronto Hydro distribution system under the following situations:

(a) internal faults within the generator
(b) external faults in the Toronto Hydro distribution system
(c) certain abnormal system conditions, such as over/under voltage, over/under frequency.

The Customers shall disconnect the embedded generation facility from the Toronto Hydro distribution system when:

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(a) a remote trip or transfer trip is included in the interface protection, and
(b) the Customer effects changes in the normal feeder arrangements other than those agreed upon in the operating agreement between Toronto Hydro and the Customer.

3.5.6 Net Metering Program for an Embedded Generation Facility

As a way to encourage conservation, Toronto Hydro has established a Net Metering Policy for eligible customers wishing to participate in the Net Metering program. Eligible customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the utility distribution system for credit against the energy the customer consumes from the distribution system.

Participation in the Net Metering Program is available to all Toronto Hydro customers with a generator that meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;
2. The electricity generated is conveyed to the customer's own consumption point without reliance on the Toronto Hydro distribution system;
3. The maximum cumulative output capacity of the generator does not exceed 500 kW; and
4. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof).

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro-Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the generator size, as found in Section 3.5 - Embedded Generation Facilities

The customer must have a bi-directional revenue meter that records energy flow in both directions.

In accordance with the Net Metering Regulation, Toronto Hydro has established a Net Metering Program regarding the netting of surplus generated energy with energy consumed from the Toronto Hydro supply. This program, as amended from time to time, is posted on the Toronto Hydro website and can be downloaded from
http://www.torontohydro.com/electricsystem/customer_care/cond_of_services/generation_connection/net_metering/index.cfm

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3.5.7 Ontario Power Authority (OPA) Standard Offer Program for an Embedded Generation Facility

In conjunction with the OPA Standard Offer Program (SOP), Toronto Hydro has established its policy to encourage and promote greater use of renewable energy sources such as wind, solar, photovoltaic (PV), renewable biomass, bio-gas, bio-fuel, landfill gas, or drop in water elevation for generating electricity. Renewable energy electricity generation projects with a capacity of 10 MW or less that meets the program's requirements may be connected to Toronto Hydro distribution system in order to export electricity.

In most circumstances, generating facilities participating in the Standard Offer Program will connect directly to the Toronto Hydro distribution system at a voltage of 27.6 kV or less. Output from the generating facility shall be metered as follows:

a. for generators of 10 kW or less and connected to the line side of the load meter, a bi-directional kWh meter must be installed to measure energy consumed and energy exported; and

b. for all other generators, an interval meter must be installed.

The generator will be solely responsible for any costs associated with the connection to the Toronto Hydro distribution system and any required metering installation.

The Toronto Hydro's policy for the OPA Standard Offer Program is posted, as amended from time to time, on the Toronto Hydro website and can be downloaded from
http://www.torontohydro.com/electricsystem/customer_care/cond_of_services/generation_connection/standard_offer/index.cfm

3.6 Wholesale Market Participant

Criteria for a Customer that is classified as being a Market Participant needs to be established. This section should describe any specific requirements for Customers that also are Market Participants.

Under the "Market Rules for the Ontario Electricity Market", Chapter 2, section 1.2.1, "No persons shall participate in the IESO-administered markets or cause or permit electricity to be conveyed into, through or out of IESO-controlled grid unless that person has been authorized by the IESO to do so".

All Embedded Market Participants, within the service jurisdiction of Toronto Hydro, once approved by the IESO are required to inform Toronto Hydro of their approved status in writing, 30 days prior to their participation in the Ontario Electricity market.

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A Wholesale Market Participant shall enter into a Connection Agreement in a form acceptable to Toronto Hydro. Until such time as the Wholesale Market Participant executes such a Connection Agreement with Toronto Hydro, the Wholesale Market Participant shall be deemed to have accepted and agreed to be bound by all of the Connection Agreement Terms and Conditions attached to this Conditions of Service as Schedule C to Section 6, and the terms of any operating schedule delivered to it from time to time by Toronto Hydro.

3.7 Embedded Distributor

This section should include all terms and conditions applicable to the connection of an Embedded Distributor.

All embedded distributors within the service jurisdiction of Toronto Hydro are required to inform Toronto Hydro of their status in writing 30 days prior to the supply of electricity from Toronto Hydro. The terms and conditions applicable to the connection of an embedded distributor shall be included in the Connection Agreement with Toronto Hydro.

An Embedded Distributor shall enter into a Connection Agreement in a form acceptable to Toronto Hydro. Until such time as the Embedded Distributor executes such a Connection Agreement with Toronto Hydro, the Embedded Distributor shall be deemed to have accepted and agreed to be bound by all of the terms in this Conditions that apply to such Embedded Distributor.

3.8 Unmetered Connections

This section will include all terms and conditions applicable to unmetered connection.

Toronto Hydro, at its sole discretion, may provide for new service connections without a meter being installed. These loads would generally be small in size, non-variable, and supply a single device. Examples of services that are considered for unmetered supply include traffic & railway crossing signals, pedestrian x-walk signals/beacons, bus shelters, telephone booths, CATV amplifiers, TTC switching devices and other miscellaneous small fixed loads. Other loads less than 2 kW may also be considered for unmetered connections.

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In all cases, the Customer shall contact Toronto Hydro for service supply requirements. The Customer shall provide manufacturer information and documentation with regard to electrical demand and expected hours of operation of the proposed unmetered load. Toronto Hydro may require, at its sole discretion, that the Customer provide at its sole cost, a load study acceptable to Toronto Hydro in order to determine energy consumption.

The Customer shall notify Toronto Hydro prior to making any changes to existing equipment or adding new equipment that is to be supplied from the Toronto Hydro distribution system.

Where installations involve Toronto Hydro owned poles, the method and location of attachment are subject to the approval of Toronto Hydro. Toronto Hydro may, in its sole discretion, require the Customer to enter into agreement with Toronto Hydro governing such attachments.

The Customer shall construct, at its expense, the civil infrastructure (including but not limited to poles, UG conduits, handwells, tap boxes, junction boxes, pedestals) on public road allowances or private property that is deemed required by Toronto Hydro to house or support Toronto Hydro's electrical equipment. These civil infrastructures shall be in accordance with Toronto Hydro's current standards, practices, specifications and this Conditions and are subject to inspection and acceptance by Toronto Hydro.

Toronto Hydro will provide, at the Customer's expense, for all breakouts of the Toronto Hydro civil infrastructure (i.e. cable chambers, vaults), which may be required to make the service connection. The Customer's service connection equipment shall be suitable to accept conductors installed by Toronto Hydro. The Customer shall bring its cables to a point determined by Toronto Hydro.
Toronto Hydro shall make all new connections and final disconnections to and from Toronto Hydro's distribution system. The Customer shall pay the applicable Connection Fees as outlined in Sections 3.8.1 to 3.8.4 and Table #3. Where "variable connection fees" apply, Toronto Hydro shall provide an estimate of the proposed work to the unmetered Customer. In turn, the unmetered Customer shall provide a response to proceed or not with the proposed work to Toronto Hydro within two weeks.

The Customer shall maintain its civil infrastructure in a safe condition satisfactory to Toronto Hydro. Toronto Hydro will undertake the necessary programs to maintain and enhance its distribution plant. However, if during the course of Toronto Hydro's work, relocation of Customer equipment is necessary, the Customer shall reimburse Toronto Hydro for all costs incurred for in relocating Customer's infrastructure. More specifically, Toronto Hydro will provide standard overhead or underground supply services to unmetered Customers affected by

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Toronto Hydro's construction activities at its own cost. However, where the unmetered Customer requests special construction beyond the normal Toronto Hydro standard installation in accordance with its program, the unmetered Customer shall pay the additional cost, including engineering and administration fees.

Request for payment shall be subject to Toronto Hydro having provided the unmetered Customer with adequate advance notice, prior to effecting the relocation. The unmetered Customer shall respond within two weeks of its intended plan to modify, upgrade, or remove its plant. Customer's unmetered loads include, but are not limited to the following:

3.8.1 Street Lighting

All services supplied to street lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. For rate structure details refer to Toronto Hydro's Schedule of Rates.

In addition to complying with this Conditions, all Street Lighting plant, facilities, or equipment owned by the Customer must comply with all Electrical Safety Authority (ESA) requirements.

The method and location of underground supply to Street Lighting plant from the Toronto Hydro distribution system will be established for each application through consultation with Toronto Hydro.

Charges related to the Connections of Street Lighting will be recovered via a Basic Connection Fee for a Standard Allowance/Basic Connection and a Variable Connection Fee (if applicable) consistent with the Ownership Demarcation Point defined in Table 3 in Section 5 of this Conditions for various Street Lighting Distribution systems.

3.8.2 Traffic & Railway Crossing Signals and Pedestrian X-Walk Signals/Beacons

Traffic & Railway Crossing Signals and Pedestrian X-Walk Signals/Beacons shall have a rate structure equal to General Service (< 50 kW) Class Customers. Each Traffic & Railway Crossing Signal and Pedestrian X-Walk/Beacon location is reviewed individually and is connected to Toronto Hydro's low voltage distribution system. Electrical Safety Authority (ESA) "Authorization to Connect" is required prior to connecting the service.

The nominal service voltage will be 120/240 Volts, single phase. The method and location of supply will be established for each application through

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consultation with Toronto Hydro. Supply connections to the municipal or the Province of Ontario's street lighting system will not be permitted.

The Ownership Demarcation Point for electrical equipment owned by Toronto Hydro is as follows:

- For Overhead - the top of the Customer's service standpipe/mast.
- For Underground – the line side of the connector/splice or fuse located in a handwell, tap box, junction box, adjacent to the Toronto Hydro's distribution system supplying the underground secondary service.

The Standard Allowance is the connections at Toronto Hydro's feed pole/lines and final connections at the top of the Customer's service mast (OH) or at Customer's protective device located in Customer's handwell/, tapbox, junction box, pedestal (UG) as determined by Toronto Hydro, and is recovered via a Basic Connection Fee of $350.00 (OH) and $560.00 (UG) per location/installation.

Connection assets above and beyond the Standard allowance (e.g. one span of OH service lines or UG conduit and associated service cables) will be recovered through a Variable Connection Fee, based on actual costs.

Re-design and inspection services are at the expense of the Customer. The Customer is responsible for maintaining and repairing its equipment and/or facilities.

3.8.3 Bus Shelters, Telephone booths, CATV Amplifiers, TTC Switching Devices, and Miscellaneous Small Fixed Loads

The above service types shall have a rate structure as General Service (< 50 kW) Class Customers and have the same terms and conditions as outlined in Section 3.8.2 above titled "Traffic & Railway Crossing Signals and Pedestrian X-Walk Signals/Beacons".

3.8.4 Other Loads (<2 kW) - Decorative Lighting and Tree Lighting Services

This section applies to the distribution and supply of electrical energy for decorative lighting. These installations are typically owned and maintained by a local Business Improvement Association (BIA) as a way to improving streetscape or for specific festive occasions. In addition to complying with this Conditions, all such installations must comply with the Ontario Electric Safety Code and are subject to the approval of ESA.

This section does not apply to decorative lighting that is owned by, or operated for, a municipality or the Province of Ontario.

Section 3 – CUSTOMER CLASS SPECIFIC

Decorative Lighting and Tree Lighting connected to Toronto Hydro's distribution system shall have a rate structure as General Service (<50 kW) Class Customers and have the same terms and conditions as outlined in Section 3.8.2 titled "Traffic signals and Pedestrian X-Walk Signals/Beacons".

Section 4 – GLOSSARY OF TERMS

4 SECTION 4 GLOSSARY OF TERMS

The Conditions of Service document may contain a variety of terms that should be defined in the context of this document. Where possible, glossary terms should reflect definitions in existing documents that apply to the distributor, such as the DSC Code, the Distributor's licence and Standard Supply Service Code. The text of the Conditions of Service document should be used to expand on these definitions as applicable to the Distributor.

Sources for definitions:

A Electricity Act, 1998, Schedule A, Section 2, Definitions
MR Market Rules for the Ontario Electricity Market, Chapter 11, Definitions
TDL Transitional Distribution License, Part I, Definitions
TTL Transitional Transmission License, Part I, Definitions
DSC Distribution System Code Definitions
RSC Retail Settlement Code Definitions

“Accounting Procedures Handbook” means the handbook approved by the Board and in effect at the relevant time, which specifies the accounting records, accounting principles and accounting separation standards to be followed by the distributor; (TDL, DSC)

“Affiliate Relationships Code” means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; (TDL, DSC)

“ancillary services” means services necessary to maintain the reliability of the IESO-controlled grid; including frequency control, voltage control, reactive power and operating reserve services; (MR, TDL, DSC)

"apartment building" means a structure containing four or more dwelling units having access from an interior corridor system or common entrance;

"apparent power" means the total power measured in kiloVolt Amperes (kVA);

"application for service" means the agreement or contract with Toronto Hydro under which electrical service is requested;

“bandwidth” means a distributor’s defined tolerance used to flag data for further scrutiny at the stage in the VEE (validating, estimating and editing) process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 30 percent bandwidth means a current reading that is either 30 percent lower or 30 percent higher than the measurement from an equivalent historical billing

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period will be identified by the VEE process as requiring further scrutiny and verification; (DSC)

"billing demand" means the metered demand or connected load after necessary adjustments have been made for power factor, intermittent rating, transformer losses and minimum billing. A measurement in kiloWatts (kW) of the maximum rate at which electricity is consumed during a billing period;

“Board” or “OEB” means the Ontario Energy Board; (A, TDL, DSC)

“building” means a building, portion of a building, structure or facility;

“complex metering installation” means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed; (DSC)

“Conditions of Service” means the document developed by a distributor in accordance with subsection 2.4 of the Code that describes the operating practices and connection rules for the distributor; (DSC)

“connection” means the process of installing and activating connection assets in order to distribute electricity; (DSC)

“Connection Agreement” means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection; (DSC)

“connection assets” means that portion of the distribution system used to connect a Customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor’ s main distribution system and the ownership demarcation point with that Customer; (DSC)

“Consumer” means a person who uses, for the person’ s own consumption, electricity that the person did not generate; (A, MR, TDL, DSC)

“Customer” means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions; (DSC)

"demand" means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes; (DSC)

“demand meter” means a meter that measures a Consumer’s peak usage during a specified period of time; (DSC)

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"developer" means a person or persons owning property for which new or modified electrical services are to be installed;

“disconnection” means a deactivation of connection assets that results in cessation of distribution services to a Consumer; (DSC)

“distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less; (A, MR, TDL, DSC)

“distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows; (DSC)

“distribution loss factor” means a factor or factors by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system; (RSC)

“distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out; (RSC, DSC)

“distribution system” means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main distribution system; (A, MR, TDL, DSC)

“Distribution System Code” means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to Customers and retailers and provides minimum technical operating standards of distribution systems; (TDL, DSC)

“distributor” means a person who owns or operates a distribution system; (A, MR, TDL, DSC)

"duct bank" means two or more ducts that may be encased in concrete used for the purpose of containing and protecting underground electric cables;

“Electricity Act” means the Electricity Act, 1998, S.O. 1998, c.15, Schedule A; (MR, TDL, DSC)

“Electrical Safety Authority” or “ESA” means the person or body designated under the Electricity Act regulations as the Electrical Safety Authority; (A)

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"electric service" means the Customer's conductors and equipment for energy from Toronto Hydro;

"embedded distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor; (RSC, DSC)

"embedded generation facility" means a generation facility that is not directly connected to the IESO-controlled grid but instead is connected to a distribution system; (DSC)

"embedded load displacement generation facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale; (DSC)

"embedded wholesale Consumer" means a Consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system; (DSC)

"emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system; (DSC)

"emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system; (DSC)

"energy" means the product of power multiplied by time, usually expressed in kilowatt-hours (kWH);

"Energy Competition Act" means the Energy Competition Act, 1998, S.O. 1998, c. 15; (MR)

"energy diversion" means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter readings, tap off load(s) before revenue meter or meter tampering;

"enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth; (DSC)

"expansion" means an addition to a distribution system in response to a request for additional Customer connections that otherwise could not be made; for example, by increasing the length of the distribution system; (DSC)

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"extreme operating conditions" means extreme operating conditions as defined in the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition);

“four-quadrant interval meter” means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the Customer; (DSC)

"general service" means any service supplied to premises other than those designated as Residential and less than 50kW, Large User, or Municipal Street Lighting. This includes multi-unit residential establishments such as apartments buildings supplied through one service (bulk-metered);

“generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system; (A, TDL, DSC)

“generation facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose; (A, MR, TDL, DSC)

“generator” means a person who owns or operates a generation facility; (A, MR, TDL, DSC)

“geographic distributor,” with respect to a load transfer, means the distributor that is licensed to service a load transfer Customer and is responsible for connecting and billing the load transfer Customer; (DSC)

“good utility practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America; (MR, DSC)

“host distributor” means the registered wholesale market participant distributor who provides electricity to an embedded distributor; (RSC, DSC)

"house service" means that portion of the electrical service in a multiple occupancy facility which is common to all occupants, (i.e. parking lot lighting, sign service, corridor and walkway lighting, et cetera);

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“IEC” means International Electrotechnical Commission;

“IEEE” means Institute of Electrical and Electronics Engineers;

“IESO” means the Independent Electricity Market Operator established under the Electricity Act; (A, TDL, DSC)

“IESO-controlled grid” means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation; (A, TDL, DSC)

“interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis; (RSC, DSC)

“large embedded generation facility” means an embedded generation facility with a name-plate rated capacity of 10 MW or more; (DSC)

"large user" means a Customer with a monthly peak demand of 5000 kW or greater, regardless the demand occurs in the peak or off-peak periods, averaged over 12 months;

"load factor" means the ratio of average demand for a designated time period (usually one month) to the maximum demand occurring in that period;

“load transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point; (DSC)

“load transfer Customer” means a Customer that is provided distribution services through a load transfer; (DSC)

“main distribution system” means a distribution system less the connection assets;

"main service" refers to Toronto Hydro’s incoming cables, bus duct, disconnecting and protective equipment for a Building or from which all other metered sub-services are taken;

“market participant” has the meaning prescribed in the Market Rules;

“Market Rules” means the rules made under section 32 of the Electricity Act; (MR, TDL, DSC)

“Measurement Canada” means the Special Operating Agency established in August 1996 by the Electricity and Gas Inspection Act, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131; (DSC)

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“meter service provider” means any entity that performs metering services on behalf of a distributor or generator; (DSC)
“meter installation” means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment; (RSC, DSC)

"meter socket" means the mounting device for accommodating a socket type revenue meter;

“metering services” means installation, testing, reading and maintenance of meters; (DSC)

“micro-embedded generation facility” means an embedded load displacement generation facility with a nameplate rated capacity of 10 kW or less; (DSC)

“mid-sized embedded generation facility” means an embedded generation facility with a nameplate rated capacity of less than 10 MW and:
(a) more than 500 kW in the case of a facility connected to a less than 15 kV line; and
(b) more than 1 MW in the case of a facility connected to a 15 kV or greater line; (DSC)

“MIST meter” means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to “Metering Inside the Settlement Timeframe;” (RSC, DSC)

“MOST meter” means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to “Metering Outside the Settlement Timeframe;” (RSC, DSC)

"multiple dwelling" means a Building which contains more than one self-contained dwelling unit;

"municipal street lighting" means all services supplied to street lighting equipment owned and operated for a municipal corporation;

“non-competitive electricity costs” means costs for services from the IESO that are not deemed by the Board to be competitive electricity services plus costs for distribution services, other than Standard Supply Service (SSS); (RSC)

"normal operating conditions" means the operating conditions comply with the standards set by the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition);

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“Ontario Electrical Safety Code” means the code adopted by O. Reg. 164/99 as the Electrical Safety Code; (DSC)
“Ontario Energy Board Act” means the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B; (MR, DSC)

“operational demarcation point” means the physical location at which a distributor’ s responsibility for operational control of distribution equipment including connection assets ends at the Customer; (DSC)

“ownership demarcation point” means the physical location at which a distributor’ s ownership of distribution equipment including connection assets ends at the Customer; (DSC)

“performance standards” means the performance targets for the distribution and connection activities of the distributor as established by the Board pursuant to the Ontario Energy Board Act and in the Rate Handbook; (DSC)

"person" includes an individual, a corporation, sole proprietorship, partnership, unincorporated organization, unincorporated association, body corporate, and any other legal entity;

“physical distributor,” with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer Customer, but is not responsible for connecting and billing the load transfer Customer directly; (DSC)

"plaza" means any Building containing two or more commercial business tenants;

“point of supply,” with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into the distribution system; (DSC)

"power factor" means the ratio between Real Power and Apparent Power (i.e. kW/kVA);

"primary service" means any service which is supplied with a nominal voltage greater than 750 volts;

"private property" means the property beyond the existing public street allowances;

“rate” means any rate, charge or other consideration, and includes a penalty for late payment; (TDL, DSC)

“Rate Handbook” means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates; (RSC, DSC)

Section 4 – GLOSSARY OF TERMS

"reactive power" means the power component which does not produce work but is necessary to allow some equipment to operate, and is measured in kiloVolt Amperes Reactive (kVAR);

"real power" means the power component required to do real work, which is measured in kiloWatts (kW);

“Regulations” means the regulations made under the *Ontario Energy Board Act* or the *Electricity Act*; (TDL, DSC)

“reinforcement” means an investment that a distributor makes to increase the distribution system capacity to accommodate new load on the distributor’s distribution system, consistent with the distributor’s planning, design, and construction standard.

"residential service" means a service which is less than 50kW supplied to single-family dwelling units that is for domestic or household purposes, including seasonal occupancy. At Toronto Hydro’s discretion, residential rates may be applied to apartment buildings with 6 or less units by simple application of the residential rate or by blocking the residential rate by the number of units;

“retail”, with respect to electricity means,

a) to sell or offer to sell electricity to a Consumer
b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) to act or offer to act as an agent or broker for a Consumer with respect to the sale or offering for sale of electricity; (A, MR, TDL, DSC)

“Retail Settlement Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor’s obligations and responsibilities associated with financial settlement among retailers and Consumers and provides for tracking and facilitating Consumers transfers among competitive retailers; (TDL, DSC)

“retailer” means a person who retails electricity; (A, MR, TDL, DSC)

"secondary service" means any service which is supplied with a nominal voltage less than 750 Volts;

“service agreement” means the agreement that sets out the relationship between a licensed retailer and a distributor, in accordance with the provisions of Chapter 12 of the Retail Settlement Code; (RSC)

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“service area,” with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity; (A, TDL, DSC)
"service date" means the date that the Customer and Toronto Hydro mutually agree upon to begin the supply of electricity by Toronto Hydro;

“small embedded generation facility” means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line; (DSC)

“Standard Supply Service Code” means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act; (TDL)

"sub-service" means a separately metered service that is taken from the main Building service;

"supply voltage" means the voltage measured at the Customer's main service entrance equipment (typically below 750 volts). Operating conditions are defined in the Canadian Standards Association ("CSA") Standard CAN3-C235 (latest edition);

"temporary service" means an electrical service granted temporarily for such purposes as construction, real estate sales, trailers, et cetera;

"terminal pole" refers to the Toronto Hydro’s distribution pole on which the service supply cables are terminated;

“total losses” means the sum of distribution losses and unaccounted for energy; (DSC)

"transformer room" means an isolated enclosure built to applicable codes to house transformers and associated electrical equipment;

“transmission system” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose; (A, MR, TDL, DSC)

“Transmission System Code” means the code, approved by the Board, that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with Customers, as well as establishing the standards for connection of Customers to, and expansion of a transmission system; (DSC)

“transmit”, with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts; (A, TDL, DSC)

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"transmitter" means a person who owns or operates a transmission system; (A, MR, TDL, DSC)

"unaccounted for energy" means all energy losses that can not be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and unmetered loads, energy theft and non-attributable billing errors; (DSC)

"unmetered loads" means electricity consumption that is not metered and is billed based on estimated usage; (DSC)

"validating, estimating and editing (VEE)" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes; (MR, DSC)

"wholesale buyer" means a person that purchases electricity or ancillary services in the IESO-administered markets or directly from a generator; (TDL, DSC)

"wholesale market participant", means a person that sells or purchases electricity or ancillary services through the IESO- administered markets; (RSC, DSC)

"wholesale supplier" means a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person, other than a Consumer; (TDL, DSC)

Section 5 – TABLES

Table 1.1 **Demarcation Points & Charges for Connection Assets and Disconnection for Class 1 and Class 2 Customers**

Table 1.2 **Demarcation Points & Charges for Connection Assets and Disconnection for Class 3**

Table 1.3 **Demarcation Points & Charges for Connection Assets and Disconnection for Class 4 and Class 5**

Table 2 **Basic Connection Fee and Disconnection Fee**

Table 3 **Street Lighting Service – Points of Demarcation & Connection Charges**

Table 4 **Customer Owned Transformers (Article 3.4.1)**

Table 5 **Meter Sockets (Article 2.3.7.1.2)**

Table 6 **Meter Cabinets (Article 2.3.7.1.2)**

Table 7 **Instrument Transformers and Enclosures (Article 2.3.7.2)**

Table 8 **Meter Centres (Article 2.3.7.1.2)**

Table 9 **Toronto Hydro Distribution Construction Standards Price List**

TABLE 1.1 Demarcation Points & Charges for Connection Assets and Disconnection

Rate/Customer Class	Ownership Demarcation Point	Standard Allowance (Basic Connection)	Basic Connection Fee (for Std. Allowance)	Variable Connection Fee	Additional Services charged to customer (as part of Var. Connections)	Service Disconnection Fee (Initiated by customer request)
CLASS 1 Residential - Single service						
Overhead	Top of Customer's Service Mast	up to 30 m OH service lines from Distributor's "feed" pole or lines. Includes connections at feed pole or lines, at customer's service mast, and equivalent average credit for transformation equipment.	Recovered through Distributor's rates	Customer charged Actual costs for connection assets beyond standard allowance.	Customers requesting an UG service in OH area will be required to pay 100% connection costs less the Standard allowance for an OH service.	Recovered through Distributor's Tarrifs or rates. See Table 2
Underground (Not requiring Transformation Facilities on customer's property)	Line side of customer's Meter Base	equivalent credit to Class 1 Residential Overhead Single Service	Recovered through Distributor's rates	Customer charged Actual costs for connection assets beyond standard allowance, including street crossing. *If customer's load requires transformation facilities on customer's property, refer to "General Service" Rate Class catergory for Underground service with Transformation.*		Recovered through Distributor's Tarrifs or rates. See Table 2
CLASS 2 General Service 0 - 50 kW						
Overhead - Single Service	Top of Customer's service mast	equivalent credit to Class 1 Residential Overhead Single Service	Recovered through Distributor's rates	Customer charged Actual costs for connection assets beyond standard allowance.	Additional or redesign due to changes in customer initial proposal; electrical inspections more than standard allowance	Recovered through Distributor's Tarrifs or rates. See Table 2
Underground - Single Servic	Line side of customer's Main disconnect switch	equivalent credit to Class 1 Residential Overhead Single Service	Recovered through Distributor's rates	Customer charged Actual costs for connection assets beyond standard allowance.	Additional or redesign due to changes in customer initial proposal; electrical inspections more than Standard Allowance and all civil inspections.	Recovered through Distributor's Tarrifs or rates. See Table 2

TABLE 1.2 Demarcation Points & Charges for Connection Assets and Disconnectio

Rate/Customer Class	Ownership Demarcation Point	Standard Allowance (Basic Connection)	Basic Connection Fee (for Std. Allowance)	Variable Connection Fee	Additional Services charged to customer (as part of Var. Connections)	Service Disconnection Fee (Initiated by customer request)
CLASS 3-A **General Service 50 kW - 999 kW**						
Overhead - Single building Bulk Metered or Suite Metering (Not requiring Transformation Facilities on private property)	Top of Customer's service mast	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance.	Additional or redesign due changes in customer initial proposal; electrical inspections more than standard allowance	Customer charged fixed, average costs associated with disconnection and/or removal of connection assets up to the demarcation point. See Table 2
Underground - Single Building Bulk Metered or Suite Metering (Not requiring Transformation Facilities on private property)	Line side of customer's Main disconnect switch	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including cable chamber(s), UG conduits as required	Additional or redesign due changes in customer initial proposal; electrical inspections more than Std. Allowance and all civil inspections.	Customer charged actual costs associated with disconnection and/or removal of connection assets up to the demarcation point. See Table 2
Overhead - Single Building Bulk Metered or Suite Metering (Requiring Transformation Facilities on private property)	Line side of customer's Main disconnect switch (secondary UG) OR Top of customer's service mast (secondary OH)	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including transformer(s), Tx. connections, associated switching equipment, transformer pole(s), cable chamber(s), UG conduits as applicable.	Additional or redesign due changes in customer initial proposal; electrical inspections more than Std. Allowance and all civil inspections and related feeder switching/scheduling	Customer charged actual costs associated with the disconnection and/or removal of connection assets including cables, transformers and related vault equipment up to the demarcation point and, related feeder switching and scheduling
Underground - Single Building Bulk Metered or Suite Metering (Requiring Transformation Facilities on private property)	Line side of customer's Main disconnect switch or customer's bus	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including transformer(s), Tx. connections, associated switching equipment, transformer pads, transformer vaults, cable chambers,cable pu rooms, UG conduits and cabling and road crossing (as applicable)	Additional or redesign due changes in customer initial proposal; electrical inspections more than Std. Allowance and all civil inspections and related feeder switching/scheduling	Customer charged actual costs associated with the disconnection and/or removal of connection assets including cables, transformers and related vault equipment up to the demarcation point and related feeder switching and scheduling

TABLE 1.3 Demarcation Points & Charges for Connection Assets and Disconnection

Rate/Customer Class	Ownership Demarcation Point	Standard Allowance (Basic Connection)	Basic Connection Fee (for Std. Allowance)	Variable Connection Fee	Additional Services charged to customer (as part of Var. Connections)	Service Disconnection Fee (Initiated by customer request)
CLASS 3-B **General Service 50 kW - 999 kW**						
Underground (Muti-units or Townhouse Complex with Transformation Facilities on private property other than supplied from primary distribution systems built along private streets)	(Bulk meter) First point of connection past transformers on private property as applicable, i.e. a) Tx. Secondary spade b) cable chamber c) tap box d) meter center	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including transformer(s), associated switching equipment, transformer pads, transformer vaults, cable chambers, connections in cable chamber(s), tap boxes excess UG conduit & cabling.	Additional or redesign due to changes in customer initial proposal; electrical inspections more than Std. Allowance and all civil inspections and related feeder switching/scheduling	Customer charged actual costs associated with the disconnection and/or removal of connection assets including cables, transformers and related vault equipment up to the demarcation point and related feeder switching and scheduling See Table 2
	(Townhouse individual meter) line side of individual meter base	equivalent credit to Class 1 Residential Overhead Single Service applied to each meter	Recovered through Distributor's rates	Customer charged Actual costs for connection assets beyond standard allowance.		Recovered through Distributor's Tarrifs or rates.
Underground (Muti-units or Townhouse Complex with NO Transformation Facilities on private propery or supplied from primary distribution system built along private streets)	(Bulk meter) First point of connection past Distributor's system onto private private as applicable I.e. a) cable chamber b) tap box c) meter center	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including cable chamber(s), excess UG conduit and cabling.	Additional or redesign due to changes in customer initial proposal; electrical inspections more than Std. Allowance and all civil inspections.	Customer charged actual costs associated with the disconnection and/or removal of connection assets up to the demarcation point See Table 2
	(Townhouse individual meter) line side of individual meter base	equivalent credit to Class 1 Residential Overhead Single Service applied to each meter	Recovered through Distributor's rates	Customer charged Actual costs for connection assets beyond standard allowance.		Recovered through Distributor's Tarrifs or rates.
CLASS 3-C **Residential Subdivision** (development with more than 5 lots)	Line side of customer's meter base (UG) Top of Customer's service mast (OH)	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	blended costs net of basic allowance credit		
CLASS 4 & 5 **General Service 1000kW and Up**						
Underground Single/Multiple Buildin Bulk Metered or Suite Metering (Requiring Transformation Facilities on private property)	Line side of Customer's main bus	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including transformer(s), Tx. connections, associated switching equipment, transformer pads, transformer vaults, cable chambers,cable pull rooms, UG conduits, excess cabling and street crossings	Additional or redesign due to changes in customer initial proposal; electrical inspections more than Std. Allowance and all civil inspections and related feeder switching/scheduling	Customer charged actual costs associated with the disconnection and/or removal of connection assets including cables, transformers and related vault equipment up to the demarcation point and related feeder switching and scheduling See Table 2
Underground Single/Multiple Buildin Bulk Metered or Suite Metering (Customer owned Sub-Station) (Requiring Transformation Facilities on private property) *Note: Individual Suite Metering will negate the Transformer Allowance Discount*	Pot head Terminations at line side of Customer's High Voltage Switchgear	equivalent credit to Class 1 Residential Overhead Single Service	See Table 2	Customer charged Actual costs for connection assets beyond standard allowance, including cable chamber(s), cable pullroom, excess UG conduit and cabling and street crossing	Additional or redesign due changes in customer initial proposal; electrical & Swgr inspections more than Std. Allowance; all civil inspection and related feeder switching/ scheduling; additional Hi-pot, protection & control relays, wiring and relay settings associated with pilot wire prot. or other extra reliablity systems	Customer charged actual costs associated with the disconnection and/or removal of connection assets including related feeder switching and scheduling See Table 2

TABLE 2 - Service Connection and Disconnection Feee

IMPORTANT:
The range of services listed below may not be applicable in all districts due to the restrictions imposed by the distribution system in certain areas.

Rate/Customer Class	Ownership Demarcation Point	Service Connection Fee (*) (Subject to annual review)	Service Disconnection Fee (Initiated by Customer)
CLASS 1 - Residential - Single service			
Overhead	Top of Customer's Service Mast	- Standard Basic Connection recovered through hydro rates ($1,310.00)	(No charge - Recovered through rates)
Underground (Not requiring Transformation Facilities on customer's property)	Line side of customer's Meter Base	- Variable Connection Charges collected directly from the Customer	(No charge - Recovered through rates)
CLASS 2 - General Service 0 - 50 kW			
Overhead - Single Service	Top of Customer's service mast	- Standard Basic Connection recovered through hydro rates ($1,310.00)	(No charge - Recovered through rates)
Underground - Single Service (Not requiring Transformation Facilities on customer's property)	Line side of customer's Main disconnect switch	- Variable Connection Charges collected directly from the Customer	(No charge - Recovered through rates)
CLASS 3A - General Service 50 kW - 999 kW			
Overhead - Single Service (Not requiring Transformation Facilities on private property)	Top of Customer's service mast	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	All Service sizes : $235.00
Underground - Single Service (Not requiring Transformation Facilities on private property)	Line side of customer's Main disconnect switch	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	Typical 400A, 120/208V : $2,200.00 Up to 100A, 347/600V : $2,200.00 *200A, 347/600V : $2,200.00 **600A, 120/208V :$7,900.00 **800A, 120/208V : $7,900.00
(Requiring Transformation Facilities on private property)	Line side of customer's Main disconnect switch or customer's bus	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	Typical Tx Vault - cable chamber, U/G : $13,000.00 Pad Tx - cable chamber, U/G : $6,000 Pad Tx - radial feed dip/riser, U/G : $5,000 (add $3,000 for a radially fed Tx vault) O/H Primary tap to a customer's termination structure $1,950
CLASS 3B - General Service 50 kW - 999 kW			
Underground (Muti-units or Townhouse Complex with Transformation Facilities on private property other than supplied from primary distribution systems built along private streets)	(Bulk meter) First point of connection past transformers on private property a) Tx. Secondary spade b) meter center c) cable chamber d) tap box	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	Typical All Service sizes : $8, 425.00
	(Townhouse individual meter) Line side of customer's Meter Base		(No charge - Recovered through rates)
Underground (Muti-units or Townhouse Complex with NO Transformation Facilities on private propery or supplied from primary distribution system built along private streets)	(Bulk meter) First point of connection past Distributor's system onto private a) tap box b) meter base/center c) cable chamber	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	Typical All Service sizes : $3,725.00
	(Townhouse individual meter) Line side of customer's Meter Base	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	(No charge - Recovered through rates)
CLASS 3C			
Residential Subdivision (development with more than 5 lots)	Line side of customer's Meter Base Top of Customer's Service Mast	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	
CLASS 4 & 5 - General Service 1000kW and Up			
Underground (Requiring Transformation Facilities on private property)	Line side of Customer's main bus	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	Typical Tx Vault - cable chamber, U/G : $13,000.00 Pad Tx - cable chamber, U/G : $6,000 Pad Tx - radial feed dip/riser, U/G : $5,000 (add $3,000 for a radially fed Tx vault) O/H Primary tap to a customer's termination structure $1,950
Underground (Customer owned Sub-Station)	Pot head Terminations at line side of Customer's High Voltage Switchgear	- Standard Basic Connection recovered through hydro rates ($1,310.00) - Variable Connection Charges collected directly from the Customer	Typical All Service sizes : $5,000.00

(*) Typical connection costs by Class of Customers are available upon request

Section 5 – TABLES

TABLE 3 – New or Upgraded Street Lighting Services – Point of Demarcation and Connection Charges

Types of Street Lighting. Distribution Systems	Ownership Demarcation Point	Standard Allowance	Basic Connection Fee (subject to annual review)	Variable Connection Fee (**)
Municipal Lights attached to Distributor's pole and connected to Distributor's 120/240V "house lighting" secondary bus/lines	a) line side of protective device (i.e. fuse, disconnect switch) b) If no protective device, point of connection on Distributor's feed pole/lines	Connections at Distributor's feed pole/lines.	$350.00	
Municipal Street Lighting branch circuits and equipment (lights) attached to Distributor's poles	Line side of the first protective device protecting the Street Lighting branch circuit	Connections at Distributor's feed pole/lines.	$350.00	Customer charged actual costs for connection assets above and beyond Standard Allowance (e.g. OH service lines or UG conduit and cables; additional connections)
Municipal Street Lighting branch circuits, poles, and equipment /lights *overhead* supplied (i.e. Municipal Street Lighting plant) totally separate from Distributor's system	Line side of the first protective device	Connections at Distributor's feed pole/lines or at Municipal – Street Lighting Plant	$375.00	Customer charged actual costs for connection assets above and beyond Standard Allowance (e.g. OH service lines or UG conduit and cables; additional connections)
Municipal Street Lighting branch circuits, poles and equipment /lights *underground* supplied (i.e. Municipal Street Lighting plant) totally separate from Distributor's system	Line side of the connector/splice or fuse within the Customer's facility or plant. (*)	Connections at closest physical infrastructure to underground Distribution plant.	$375.00	Customer charged actual costs for connection assets above and beyond Standard Allowance (e.g. Cable Chamber/Vault breakout; UG conduit and cables; additional connections)

* Electrical circuits that are part of the Toronto Hydro underground infrastructure (i.e. concrete encased duct bank, vault, and cable chamber systems) are owned and operated by Toronto Hydro
** Consulting and engineering work is not included and may be separately charged

Section 5 – TABLES

Table 4 – Customer Owned Transformers (Article 3.4.1)

Transformer Voltage		Recommended Primary Tap Voltage					
Primary	Secondary	+5%	+2½%	0	-2 ½%	-5 %	-7 ½%
27600 grd.Y/16000 27600 grd.Y/16000	less than 750 13800 grd.Y/8000	28980	28290	27600	26910	26220	
27600	2400/4160 Y		28290	27600	26910	26220	25530
13860	2400/4160 Y		14206	13860	13513	13167	12820
13860 13860 grd.Y/8000	less than 750	14553	14206	13860	13513	13167	

Section 5 – TABLES

Table 5 Meter Sockets (Article 2.3.7.1.2)

SELF-CONTAINED SOCKET METERING			
Voltage	Phase	Wire	Maximum Service Switch Size Rating Amperes
120/240	1	3	200
120/240	1	3	400 *
208/120	2	3	200
208/120	3	4	200
600/347	3	4	200
600 **	3	3	200

* Meter socket contains a 3 wire current transformer and transformer type meter.

** Used only for existing services where grounded supply is not available

Notes:

1. Only CSA approved meter sockets are to be used.

2. Meter sockets shall be mounted so that the midpoint of the meter is set at 1700 mm ± 100 mm.

3. Where the supply is grounded, 600 V. metering shall be 4 wire. Where the Customer does not require a neutral, a full size neutral conductor sized in accordance with Table 17 of the Ontario Electrical Safety Code must be provided to all meter cabinets or sockets. The neutral conductor is to be terminated in the socket (or cabinet) on an insulated block in accordance with the Ontario Electrical Safety Code.

Section 5 – TABLES

Table 6 Meter Cabinets (Article 2.3.7.1.2)

METER CABINETS				
Voltage	Phase	Wire	Main Switch Size in Amperes	Meter Cabinets (see description below)
120/240	1	3	Over 400	A
208/120 416/240 600/347	3	4	Over 200 – 800	A
			Over 800	B
600*	3	3	Over 200 – 400	A
			Over 800	B

* Only for existing services where grounded supply is not available.

Meter Cabinet Descriptions

A – 48” x 48” x 12” complete with removable 44” x 44” backplate.
B – 36” x 36” x 12” connected to switchgear instrument transformer compartment.

Notes:

1. Meter cabinets shall be fabricated of minimum # 16 gauge steel.
2. Cabinets shall have side-hinged doors opening at the center and be equipped with three-point latching and provision for padlocking.
3. The maximum distance from the floor to the top of the cabinet shall be 2000 mm.
4. Where two or more circuits are used in one meter cabinet, Toronto Hydro will issue specific metering requirements.

Section 5 – TABLES

Table 7 Instrument Transformers and Enclosures (Article 2.3.7.2)

Metering Transformers and Compartments						
Voltage (Volts)	Phase	Wire	Service Size (Amperes)	Compartment Size	Number of Metering Transformers (Provision for)	
					Current	Voltage
240/120 208/120 N/W	1 3	3 3	Up to 800	A	1 or 2	0
			Over 800 Up to 4000	B		
Only f	3	4	Up to 800	A	3	3
			Over 800 Up to 4000	B	3	
600 (*)	3	3	Up to 800	A	2	2
			Over 800 Up to 4000	B	2	
Voltages up to 600	3 (*) 3	3 (*) 4	Over 4000	C	2 3	2 3

* Only for existing services where grounded supply is not available.

COMPARTMENT SIZES [width x height x depth (from CT mounting plate)]

A - 762mm x 762mm x 210mm (30” x 30” x 8.25”)
B - 965mm x 762mm x 324mm (38” x 30” x 12.75”)
C - 965mm x 914mm x 381mm (38” x 36” x 15”)

NOTES: 1. Instrument transformers will be provided by Toronto Hydro and shall be installed in the switchgear by the manufacturer. The manufacturer shall not disassemble and/or change in any manner the Toronto Hydro equipment sent to the manufacturer.

2. Voltage transformer connections shall be connected on the line side of the current transformers. Current transformers shall be installed with their polarity marks towards the incoming Toronto Hydro supply.

Section 5 – TABLES

Table 8 Meter Centres (Article 2.3.7.1.2)

Meter centers may be used for 750 V applications or less, as far as they meet the following specifications:

1) Side-hinged doors or panels shall be installed over all sections of the switchboard where Toronto Hydro may be required to work, such as unmetered sections and those sections containing breakers, switches and meter mounting devices. Hinged doors or panels shall have provision for sealing and padlocking in the closed position. Where bolts are used, they shall be of the captive knurled type. The hinged covers over breakers or switches shall be so constructed that the covers cannot be opened when sealed or padlocked.
2) Breakers or switch handles shall have provision for positive sealing and padlocking in the "off" position.
3) Meter mounting devices shall be wired so as to be on the "load" side of the breakers or switches.
4) Each combination meter socket and breaker panel shall have adequate space for permanent Customer identification with respect to street address and/or unit number.
5) The centre of the bottom row of meter sockets shall be not less than 600 mm from the finished floor. The centre of the top row of meter sockets shall be not less than 1800 mm from the finished floor.
6) The distance between adjacent meter socket rims in the horizontal plane shall not be less than 152 mm.
7) The distance between adjacent meter socket rims in the vertical plane shall be as follows:
    a) For 100 A., 4 or 5 jaw , not less than 76 mm.
    b) For 100 A., 7 jaw, not less than 152 mm.
8) The meter mounting socket and sealing ring shall be acceptable to Toronto Hydro.
9) Where a neutral is required, the meter mounting device shall have a pre-wired, ungrounded neutral connection to the 5th or 7th terminal. The connection, if not made directly to the neutral bus, shall be not less than #12 AWG copper or equivalent.

Section 5 – TABLES

Table 9

Toronto Hydro Distribution Construction Standards Price List

	Title Section	*Individual Section Cost ($) (GST not Included)*
0	Index	N/A
1	How to use the Standards, General Info	100
2	Material Index	500
3	Clearances	500
4	Poles and Pole Settings	1,500
5	Poles Framing	2,500
6	RESERVED FOR FUTURE USE	N/A
7	Anchoring & Guying	1,000
8	Overhead Conductors and Connectors	1,000
9	Overhead Transformers	1,000
10	Overhead Switches	1,000
11	Overhead Primary and Secondary Services	1,000
12	Secondary and Primary Service Risers	1,000
13	Underground Transformers and Switchgears	3,500
14	Padmounted Transformers	1,000
15	Underground Secondary and Primary Services	1,000
16	Underground Cable, Terminations, Joints	3,500
17	Revenue Metering	200
18	Grounding	200
19	Surge Arresters	200
20	Faulted Circuit Indicators	200
21	OH & UG Stenciling	1,000
22	Water Heaters	200
23	Foreign Attachments	500
24	Fusing	500
25	OH & UG Material Catalogue	500
26	RESERVED FOR FUTURE USE	N/A
27	Legend/Drafting Symbols	100
28	OH & UG Material Fabrications	500
29	RESERVED FOR FUTURE USE	N/A
30	Street Lighting	3,000
31	Civil Construction	4,000
32	Telecommunications	1,000
33	Supplementary Compatible Units	N/A
34	Engineering information/References	200
	Cost of complete set of Standards	***16,000***
	Maintenance charge per year (full set of updates)	***1,000***

For purchasing Construction Standards please contact the supervisor of Standards

Section 6 – REFERENCES

REFERENCES

1. **Economic Evaluation Model for Distribution System Expansion**
   Refer to Appendix B of the Distribution System Code:
   "Methodology and Assumptions for an Economic Evaluation"

2. **Standard Toronto Hydro Connection Agreements and Terms of Conditions**
   - Schedule A:
     - Toronto Hydro-Electric System Limited Connection Agreement
   - Schedule B1:
     - Micro-Embedded Generation Facility Connection Agreement
   - Schedule B2:
     - Form of Connection Agreement for a Small, Mid-Sized, and Large Embedded Generation Facility
   - Schedule B3:
     - Connection Agreement for an Embedded Generation Facility Larger than 10 MW
   - Schedule C:
     Wholesale Market Participant Connection Agreement Terms and Conditions
   - Schedule C:
     - Wholesale Market Participant Connection Agreement Terms and Conditions

3. **Toronto Hydro Parallel Generation Requirements**

4. **Toronto Hydro Requirements for the Design & Construction of Customer-Owned High Voltage Substations**

5. **THESL Requirements for Customer-Owned Structures**

6. **THESL Metering Requirements 750 Volts or Less**

7. **Metering Requirements for 13.8 & 27.6 kV Customer-Owned Substations**

8. **Construction Contractor Qualification Application for Contestable Work**

SECTION #6 REF. #1

DSC - APPENDIX B

Methodology and Assumptions for

An Economic Evaluation

Last Revised January 23, 2007

B.1 COMMON ELEMENTS OF THE DISCOUNTED CASH FLOW MODEL

To achieve consistent business principles for the development of the elements of an economic evaluation model, the following parameters for the approach are to be followed by all distributors.

The discounted cash flow (DCF) calculation for individual projects will be based on a set of common elements and related assumptions listed below.

Revenue Forecasting

The common elements for any project will be as follows:

(a) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below;

(b) Customer Revenue Horizon as specified below;

(c) Estimate of average energy and demand per added customer (by project) which reflects the mix of customers to be added – for various classes of customers, this should be carried out by class;

(d) Customer additions, as reflected in the model for each year of the Customer Connection Horizon; and

(e) Rates from the approved rate schedules for the particular distributor reflecting the distribution (wires only) rates.

Capital Costs

Common elements will be as follows:

(a) An estimate of all capital costs directly associated with the expansion to allow forecast customer additions.

(b) For expansions to the distribution system, costs of the following elements, where applicable, should be included:
- distribution stations;
- distribution lines;
- distribution transformers;

- secondary busses;
- services; and
- land and land rights.

Note that the "Ownership Demarcation Point" as specified in the distributor's Condition of Service would define the point of separation between a customers' facilities and distributor's facilities.

(c) Estimate of incremental overheads applicable to distribution system expansion.

(d) A per kilowatt enhancement cost estimate – the per kilowatt enhancement cost estimate shall be set annually and shall be based on a historical three to five year rolling average of actual enhancement costs incurred in system expansions.

(e) For residential customers, the amount the cost of the basic connection referred to in section 3.1.4 of the Code.

(f) For non-residential customers, if the distributor has chosen to recover the non-residential basic connection charge as part of its revenue requirement, a description of, and the amount for, the connection charges referred to in section 3.1.5 of the Code that have been factored into the economic evaluation.

Expense Forecasting

Common elements will be as follows:

(a) Attributable incremental operating and maintenance expenditures - any incremental attributable costs directly associated with the addition of new customers to the system would be included in the operating and maintenance expenditures.

(b) Income and capital taxes based on tax rates underpinning the existing rate schedules.

(c) Municipal property taxes based on projected levels.

Specific Parameters/Assumptions

Specific parameters of the common elements include the following:

APPENDIX B -
METHODOLOGY AND ASSUMPTIONS FOR AN OFFER TO CONNECT ECONOMIC EVALUATION

(a) A maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities.[1]

(b) A maximum customer revenue horizon of twenty five (25) years, calculated from the in service date of the new customers.[2]

(c) A discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

(d) Discounting to reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted. The same approach to discounting will be used for revenues and operating and maintenance expenditures.[3]

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[1] For customer connection periods of greater than 5 years an explanation of the extension of the period will be provided to the Board

[2] For example, that the revenue horizon for customers connected in year 1, is 25 years while for those connected in year 3, the revenue horizon is 22 years.

[3] For certain projects Capital Expenditures may be staged and can occur in any year of the five year Connection Horizon.

B.2 DISCOUNTED CASH FLOW (DCF) METHODOLOGY

Net Present Value ("NPV")	=	Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital
1. PV of Operating Cash Flow	=	P V of Net Operating Cash (before taxes) - P V of Taxes
a) PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied. Incremental after tax weighted average cost of capital will be used in discounting.
Net (Wires) Operating Cash	=	(Annual(Wires) Revenues - Annual (Wires) O&M)
Annual (Wires) Revenue	=	Customer Additions * [Appropriate (Wires) Rates * Rate Determinant]
Annual (Wires) O&M	=	Customer Additions * Annual Marginal (Wires) O&M Cost/customer
b) PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
Annual Municipal Tax	=	Municipal Tax Rate * (Total Capital Cost)
Total Capital Cost	=	Distribution Capital Investment + Customer Related Investment + overheadsd at the project level
Annual Capital Taxes	=	(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)
Annual Capital Tax	=	(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax – Annual Capital Tax)

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

2. PV of Capital	=	P V of Total Annual Capital Expenditures

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure	=	(for New Facilities and/or Reinforcement Investments + Customer Specific Capital + Overheads at the project level). This applies for implicated system elements at the utility side of the “Ownership Demarcation Line”.

Note: Above is discounted to the beginning of year one over the customer addition horizon

3. PV of CCA Tax Shield

P V of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of: $\frac{[(\text{Income tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the ½ year CCA rule.

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

SECTION #6 - REFERENCE #2

Standard Toronto Hydro Connection Agreements Terms of Conditions

- Schedule A:
  - Toronto Hydro-Electric System Limited Connection Agreement

- Schedule B1:
  - Micro-Embedded Generation Facility Connection Agreement

- Schedule B2:
  - Form of Connection Agreement for a Small, Mid-Sized, and Large Embedded Generation Facility

- Schedule B3:
  - Connection Agreement for an Embedded Generation Facility Larger than 10 MW

- Schedule C:
  - Wholesale Market Participant Connection Agreement Terms and Conditions

Section 6 – REFERENCES

Schedule A

Load Customer Connection Agreement - Terms and Conditions

See next 8 pages for terms and conditions

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED CONNECTION AGREEMENT

Date:

Customer Name ("Customer"):

Type of Business:

Customer Account Number:

Service Address: Postal Code:

Billing Address: Postal Code:

Business Phone Number:

Home Phone Number:

Toronto Hydro-Electric System Limited ("THESL") is engaged in the business of distributing electricity in the City of Toronto, in the Province of Ontario;

The Customer owns the facilities ("Facilities") located at the Service Address set forth above ("Site"); and

The Customer wishes to have the Facilities connected to the THESL Distribution System.

NOW THEREFORE the Customer and THESL agree as follows:

1.0 **Connection:** The Facilities shall be connected to the THESL Distribution System and remain Energized at the Point of Connection from the Connection Date for the duration of the Term on the terms and subject to the conditions set out in this Agreement.

2.0 **Payment**: The Customer shall (i) pay THESL for all electricity distribution services provided by THESL to the Site during the Term in accordance with such rates as may be approved by the Ontario Energy Board ("OEB") from time to time for the appropriate class rating to which the services apply; (ii) make such payments in accordance with THESL's billing cycle as notified to the Customer from time to time; and (iii) pay late payment and other charges and pay such deposits as may be required by THESL as part of the OEB-approved rate structure. The Customer shall also pay to THESL such other charges as THESL may be required by applicable law to bill and/or collect for third parties including electricity retailers, the Independent Market Operator, Ontario Energy Board and any transmission company.

3.0 **Conditions of Service**: In addition to the obligations set forth in this Agreement, the Customer shall be bound by, and shall comply with, all provisions of THESL's Conditions of Service.

4.0 **General Conditions of Connection:** THESL and the Customer agree that the terms and conditions attached hereto as Schedule A, General Conditions of Connection, shall apply and be binding on the Parties.

5.0 **Notices**: Any notices required or permitted to be made under this Agreement shall be given by prepaid registered mail or delivered by hand or courier to the person executing this Agreement at the address set forth below. If such notice is given by mail, such notice shall be deemed received on the fifth Business Day after the date of mailing. If such notice is delivered by hand or by courier, such notice shall be deemed to have been received on the actual date of delivery.

The designation of the person to be notified or the address of such person may be changed at any time by either party hereto by notice in writing given pursuant to this Section 5.0 and such change shall take effect from the deemed date of receipt as specified in this Section 5.0.

IN WITNESS WHEREOF, THESL and the Customer, through their authorized representatives, have executed this Agreement as of the day and year first written above.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By: _____

Name:
Title:

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario
M5B 1K5
Telephone: (416) ●
Fax: (416) ●

[Registered Property Owner]

By: _____

Name:
Title:

Name:
[Address]
Telephone No.: ●
Fax No: ●
Email: ●

SCHEDULE "A"
GENERAL CONDITIONS OF CONNECTION

1.0 **Completion Of Testing:** Notwithstanding anything else in this Agreement to the contrary, without limiting any other obligations of the Customer, the Customer shall not have the right for the Facilities to be connected or remain Energized until the Facilities have successfully completed Testing.

2.0 **Approval of Structures, Equipment and Apparatus:** All electrical structure, equipment and apparatus used by the Customer at the Facilities shall be subject to the prior approval of THESL, acting reasonably. A failure by the Customer to install, or where installed, replace or remove any structures, equipment or apparatus in accordance with a direction from THESL, acting reasonably, shall be considered an Event of Default pursuant to Condition 12.0 and THESL shall be entitled to terminate this Agreement pursuant to Condition 13.0 and the provisions of Condition 14.0 shall apply.

3.0 **Testing:** THESL shall provide prior written notice ("Notice of Testing") to the Customer of the Tests which must be performed. The Customer shall obtain prior written approval from THESL for the contractor who will perform the Tests; provided that if a contractor is on the most recent list of approved contractors published by THESL from time to time no written approval shall be required. After completion of Testing, the Customer shall deliver the results of the Tests to THESL.

4.0 **No Damages:** The Facilities, when inter-connected to the THESL Distribution System, shall not adversely affect or damage, (a) the health and safety of THESL personnel, its contractors or the general public; (b) the structures, equipment or apparatus owned or operated by THESL; (c) the THESL Distribution System; (d) the security, safety, efficiency and reliability of THESL Distribution System; or (e) the quality of the electrical power supply or services provided by THESL to the Customer or other THESL customers.

5.0 **No Violation:** The Customer shall not, in installing, operating or maintaining the Facilities, (a) violate, or cause THESL to violate, any provision of its Distribution License; (b) contravene any laws of the Province of Ontario or any laws of Canada having force and effect in the Province of Ontario; or (c) violate any provision contained in the Conditions of Service.

6.0 **Covenants:** The Customer shall comply as soon as possible with any reasonable directive received from THESL that THESL makes for the purpose of meeting any of its obligations under its Distribution License. The Customer shall have no rights of access to THESL structures, equipment, apparatus or lands or property owned by THESL.

In the event that, as a consequence of the construction, maintenance, connection, or operation of the Facilities, damage occurs to any structure, equipment or to other apparatus owned or operated by THESL, or to the THESL Distribution System, the Customer shall, within 10 days of receipt of an invoice therefore, pay the amount of any such damage to THESL.

THESL shall be entitled to access to the property of the Customer at all reasonable times, to inspect, maintain, repair, alter, remove, replace or disconnect wires or other facilities, or to install, inspect, read, calibrate, maintain, repair, alter, remove or replace a meter, which are located on the property and to take any actions necessary to maintain the safe and reliable operation of the THESL Distribution System. The Customer shall also provide THESL with such other access as may be specified in a Conditions of Service or by law. In accessing the property of the Customer, THESL shall comply with the Customer's reasonable security practices and procedures to the extent that it is made aware of such practices and procedures.

The Customer agrees to provide suitable space for THESL's existing meters, wires, poles, cables, transformers and other equipment (collectively "Metering Equipment") at the Site

and for any Metering Equipment which THESL may be required by law to install as any time after the date of this Agreement and further agrees that no one who is not an agent of THESL shall be permitted to remove, inspect or tamper with same, including moving, inspecting or tampering with the seals. The Customer agrees that Representatives of THESL shall have reasonable access to the Site and Facilities for the purposes of reading, examining, preparing or removing their meters, wires, poles, cables, transformers and other appliances, materials and equipment and for the purpose of inspecting the Customer's appliances, equipment and wiring.

7.0 **Maintenance:** The Customer will maintain the Facilities in good and workmanlike condition in a manner consistent with the Conditions of Service and all standards specified by law. The Customer shall immediately repair or replace, as required, any equipment, apparatus or structure owned by the Customer that may affect the security, safety, efficiency or reliability of the THESL Distribution System.

8.0 **Interest:** Any amount required to be paid under this Agreement, whether for the cost of interconnection or otherwise, which is not paid on the due date therefore, shall bear interest at the rate of 1.5% calculated and compounded monthly (19.56% per annum) at and from the due date up to and including the date of payment in full of such amount, together with all interest accrued to the date of payment.

9.0 **ESA Inspection**: The Customer shall, at its expense, have the Facilities inspected and approved by the ESA and obtain a written certificate from the ESA certifying that the ESA has inspected the electrical installations of the Facilities to allow for the performance of the Tests, Testing, and in-service operation of the Facilities and deliver, or have delivered, to THESL such written certificate from the ESA. THESL will not allow the Facilities to be connected to the THESL Distribution System for the purpose of performing the Commissioning Tests hereunder until THESL receives a written connection authorization from the ESA for the Facilities and all other requirements of THESL for the connection of the Facilities to the THESL Distribution System are met.

10.0 **Reliability:** THESL shall operate in a manner consistent with its Conditions of Service in order to provide a regular and uninterrupted service to the Customer but does not guarantee a constant service of the maintenance of unvaried frequency of voltage and THESL shall not be liable for any damages whatsoever to the Customer by reason of any failure in respect thereof. The Customer shall provide for the protection of its structures, equipment and apparatus from voltage variations, operations, single line phasing and all other causes.

11.0 **Term**: Unless terminated earlier in accordance with the terms of the Agreement, this Agreement shall be effective as of the date first written above and shall continue in full force and effect until either party gives no less than 30 days written notice to the other party of its intention to terminate this Agreement ("Term"). Any such notice of termination shall specify the effective date of termination; provided that notwithstanding the delivery of a notice of termination under this Condition 11.0, THESL shall have the right to terminate this Agreement prior to the specified effective date of termination pursuant to Condition 13.0.

12.0 **Events of Default**: The occurrence of any of the following shall constitute an event of default ("Event of Default") on the part of the Customer: (a) failure to pay any sum, including interest pursuant to Condition 8.0, due and owing hereunder; (b) failure to comply with any other covenant or obligation set forth in this Agreement; or (c) the occurrence of a breach or default under any agreement which the Customer has with THESL to supply electricity to the Customer.

13.0 **Notice of Termination**: Upon the occurrence of an Event of Default, THESL shall have the right to: (a) give notice of termination to the Customer whereupon the Agreement shall terminate as at the effective date of termination specified in the notice; and/or (b) disconnect the Facilities from the THESL Distribution System in accordance with Condition 15.0 (a) below;

14.0 **Consequences of Termination**: Upon termination of the Agreement in accordance with any of its provisions, without prejudice to any other rights THESL may have: (a) all charges

outstanding pursuant to this Agreement shall immediately become due and payable to THESL by the Customer; (b) THESL shall be entitled to enter onto the Customer's property to remove, at the Customer's expense, any THESL structure, equipment or apparatus as soon as reasonably practicable; (c) the relevant provisions of this Agreement shall continue in effect after expiry or termination to the extent necessary to provide for any billings, adjustments and payments related to the period prior to the termination and for the payment of any monies due and owing pursuant to this Agreement; (d) the termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either of the parties under this Agreement, which are expressed to continue after termination of this Agreement; (e) THESL shall have no liability whatsoever to the Customer arising from such termination; and (f) THESL may, if it has not already done so pursuant to Condition 15.0, disconnect the Facilities from the THESL Distribution System.

15.0 **Right to Disconnect**: Notwithstanding anything else contained in this Agreement, THESL may disconnect the Facilities from the THESL Distribution System and, where it deems it appropriate, remove any structure, equipment or apparatus:

(a) if an Event of Default occurs, upon reasonable prior notice to the Customer; provided that: (i) THESL may, if it, in its sole discretion, deems it necessary for any reason whatsoever, disconnect the Facilities from the THESL Distribution System immediately without any notice to the Customer; and (ii) if the disconnection is as a result of non-payment of monies due and owing hereunder, THESL shall provide no less than 7 days notice of such disconnection;

(b) immediately without notice, if THESL, in its sole discretion, determines it is necessary: (i) to protect the health or safety of THESL personnel, its contractors or any third parties; (ii) to prevent damage to the THESL Distribution System or any other property; (iii) preserve the security, safety, to efficiency and reliability of the THESL Distribution System or services delivered thereunder; (iv) as a result of any other circumstances which THESL in its sole discretion, determines to be an Emergency; or (v) the Customer has failed to comply with the Ontario Electrical Safety Code.

(c) upon reasonable prior notice to the Customer to perform any unplanned inspection or maintenance;

(d) immediately without notice, upon issuance of an order or directive requiring disconnection by any court or regulatory authority having jurisdiction; or

(e) for any other reason specified in this Agreement or the Conditions of Service.

16.0 **Reconnection**: In the event THESL shall exercise any rights to disconnect the Facilities pursuant to this Agreement for an Event of Default relating to the Customer or any other reason attributable to the action or inaction of the Customer, or for any cause relating to or connected with the Customer, or the Customer requests THESL to disconnect the Facility, and the Customer shall request that the Facilities be reconnected for any reason, the Customer shall pay the costs of such reconnection as set out of the Conditions of Service or where not specified in the Conditions of Service as determined by THESL in its sole discretion, acting reasonably and in either case, such costs shall include any monies which may be due and owing to THESL under this Agreement including Section 2.0. Such costs shall be paid in full prior to the reconnection of the Facilities. Upon the request of THESL, the Customer shall comply with the provisions of Conditions 1.0, 3.0 and 9.0 prior to reconnection.

17.0 **Disconnection Request**: Upon receipt of a disconnection request by the Customer, THESL will disconnect and/or remove Toronto Hydro's structure, equipment or apparatus at the Customer's cost.

18.0 **Risk Assumed**: The Customer shall have the risk and all liability in respect of:

(a) all loss damage or injury to property owned by THESL, or to property for which THESL has jurisdiction under this Agreement, or is at law responsible for, located on the lands and premises owned by the Customer, unless due to a negligent act or omission or wilful misconduct of THESL or any of Representatives; and

(b) all loss, damage or injury to: (i) property of the Customer, or property of a third person, on the lands and premises owned by the Customer; and (ii) any person or persons (including loss of life), whether on the lands or premises owned by the Customer, or owned or used by THESL, or otherwise, resulting from the operation of the Facilities, whether in accordance with this Agreement or otherwise, except to the extent that such loss, damage or injury is the result of the negligent action or omission or wilful misconduct of THESL or any of its Representatives.

19.0 **Indemnification:** The Customer shall indemnify and save harmless THESL and all of its Representatives against all claims, losses, expenses, damages, costs, actions or proceedings incurred by, or instituted against, them which relate to, arise out of, or are attributable in any way to the testing, connecting, or operating of the Facilities and occur or arise or result from (i) a breach of, or default under, this Agreement, or (ii) the negligence or willful misconduct of the Customer or any of its Representatives .

20.0 **Limitation of Liability**: Notwithstanding any other provision in this Agreement, or any applicable statutory provision: (a) neither THESL nor any of its Representatives shall be liable to the Customer for any losses, damages, claims, liabilities, costs or expenses arising from any breach of this Agreement or any tortuous act, other than for losses, damages, claims, liabilities, costs or expenses directly resulting from the negligence or willful misconduct of THESL; and (b) neither THESL nor any of its Representatives shall be liable to the Customer under any circumstances for any indirect, incidental, special or consequential damages, whether punitive or exemplary, including damages for loss of use or profits or revenues, business interruption losses, loss of contract or loss of goodwill or other economic benefits, howsoever caused whether arising directly or indirectly from any breach of this Agreement, fundamental or otherwise, or from any tortious acts, including negligence or gross negligence or willful misconduct of THESL or any of its Representatives.

21.0 **Force Majeure**: "Force Majeure" means, any event or circumstance which is (i) beyond the reasonable control of THESL, (ii) does not result from the negligence or fault of THESL or any of its Representatives and (iii) results in, or causes, the inability of THESL to perform any of its obligations under the Agreement or results in electricity not flowing from the THESL Distribution System to the Facilities or causes the THESL Distribution System to be incapable of being operated lawfully, safely or at all; provided however that lack of funds shall not be interpreted as a cause beyond the reasonable control of THESL. If THESL is unable to carry out any of its obligations under this Agreement because of the occurrence of an event of Force Majeure, the obligations of THESL and the corresponding obligations of the Customer shall be suspended to the extent necessary by and during the continuance of such Force Majeure

22.0 **Relationship:** Nothing in this Agreement shall be deemed to constitute either party hereto as partner, agent or representative of the other party or to create any fiduciary relationship between the parties.

23.0 **Notice of Load Increase:** The Customer may not materially increase the load at the point of connection without the prior written approval of THESL, which approval may not be unreasonably withheld. The Customer shall provide THESL with all information requested by it to reasonably consider the application for approval. If any increase in load is made in contravention of this Condition 23.0, it shall be an Event of Default, THESL shall have the right to terminate this Agreement pursuant to Condition 13.0 and the provisions of Condition 14.0 shall apply to such termination. In addition to any other indemnity contained herein, the Customer shall be liable to THESL for, and shall indemnify THESL against, any damages to the

THESL Distribution System resulting from any unapproved increase in the load.

24.0 **Modifications**: From time to time certain improvements, additions or other changes ("Modifications") to Customer assets relating to, or affecting, the connection assets may be required for their economical, reliable and safe operation. The Customer may not make any material Modifications without prior written approval of THESL, which approval may not be unreasonably withheld. The Customer shall provide THESL with all information requested by it to reasonably consider the application for approval. Any approval given by THESL shall be deemed to contain the conditions that the Modifications shall be made (i) in accordance with the standards and procedures of THESL in effect at the time the Modification is made and (ii) at the Customer's expense. If any Modification is made in contravention of this Condition 24.0, it shall be an Event of Default, THESL shall have the right to terminate this Agreement pursuant to Condition 13.0 and the provisions of Condition 14.0 shall apply to such termination. In addition to any other indemnity contained herein the Customer shall be liable to THESL for, and shall indemnify THESL against, any damages to the THESL Distribution System resulting from of any unapproved Modifications.

25.0 **Waiver**: Any waiver of any right under this Agreement shall be in writing and any failure by either party to exercise any right or to enforce any remedy under this Agreement shall not be deemed to be a waiver of any other right or remedy or affect the validity of this Agreement.

26.0 **Dispute**: In the event of any dispute arising out of this Agreement, THESL and the Customer agree as follows: (a) to attempt, in good faith, to negotiate a settlement of the dispute between themselves within twenty (20) days from the date the dispute arose; and (b) in the event that the parties cannot settle the dispute between themselves, either party may, following the passage of at least twenty (20) days from the date the dispute arose (as evidenced by writing between the parties), submit the dispute for resolution in accordance with the process established under the provisions of THESL' Distribution License and Conditions of Service. Any decision under that process will be final and binding with no right of appeal.

27.0 **Global Provision**: The Customer agrees that THESL shall have the right to revise any provision in this Agreement, that it determines, in its sole discretion, is required, for any reason, (a) to protect the security, efficiency, reliability and safety of the THESL Distribution System or safety of THESL personnel or any other property or persons; or (b) to make the provisions of this Agreement consistent with a change in applicable laws or in the Conditions of Service; provided that, THESL shall provide no less than 30 days prior notice of such change to the Customer and the Customer shall have the right to terminate the Agreement within 10 days of receipt of such notice. The provisions of Condition 14.0 shall apply to any such termination.

28.0 **Miscellaneous**: The Schedules attached to this Agreement form a part of this Agreement and the Customer acknowledges that it has read the provisions contained in the attached Schedules and agrees that they form a part of this Agreement as if they were set forth in the main body of the Agreement. This Agreement constitutes the entire agreement between the Customer and THESL and supercedes all proposals, oral or written, and all other communications between the parties, relating to the subject matter of this Agreement. The invalidity, unenforceability or illegality of any provision of this Agreement shall not affect the validity, enforceability or legality of any other provision of this Agreement, which shall remain in full force and effect. This Agreement and the attached Schedules may only be modified by a written amendment signed by authorized representatives of both parties. The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws in effect in the Province of Ontario and the laws of Canada applicable therein. This Agreement shall be binding upon and ensure to the benefit of THESL and the Customer, and their respective successors and permitted assigns. The Customer may not assign its rights and/or obligations under this Agreement or any portion thereof without the prior written consent of THESL, which will not be unreasonably withheld or delayed. THESL may assign its rights and obligations

under this Agreement without the consent of the Customer. The Customer represents and warrants to THESL that it has full power and authority to enter into and perform this Agreement and the execution and performance of this Agreement will not conflict with, or constitute a breach or default under, any contract or agreement of any kind to which it is a party or any judgment, order, statute or regulation which is applicable to the Customer. THESL represents and warrants to the Customer that it has full power and authority to enter into and perform this Agreement and the execution and performance of this Agreement will not conflict with, or constitute a breach or default under, any contract or agreement of any kind to which it is a party or any judgment, order, statute or regulation which is applicable to THESL. In this Agreement, the following terms shall have the meanings set forth below:

(a) "Agreement" means this agreement, including the General Conditions of Connection and all other Schedules and all attachments, as amended from time to time.

(b) "Business Day" means any day on which The Royal Bank of Canada is open for business in Toronto, Ontario.

(c) "Conditions of Service" means the document developed by THESL in accordance with subsection 2.4 of the Distribution System Code that describes the operating practices and connection rules for THESL and is filed with the OEB as amended from time to time.

(d) "Connection Date" means the date on which the Facilities are Energized.

(e) "Distribution License" means any license to distribute electricity issued to THESL by the Ontario Energy Board.

(f) "Distribution System Code" means the code, approved by the Ontario Energy Board, and in effect at the relevant time, which, among other things, establishes the obligations of THESL and other distribution systems with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards for THESL and other distribution systems.

(g) "Energized" means the joining of the Facilities to the THESL Distribution System by means of approved work practices either initially or following a disconnection for whatever reason so that Customer may make or receive a supply of electricity to or from THESL Distribution System at the point of connection.

(h) "ESA" means the person or body designated under the *Electricity Act*, 1998, S.O. 1998, c.15, Schedule A as the Electrical Safety Authority.

(i) "Representatives" means the respective directors, officers, employers, contractors or agents of either party hereto, as applicable:

(j) "Tests" means the tests performed on the Facilities to ensure that the Facilities are designed and fit to be connected to the THESL Distribution System, and "Testing" means the performing of the Tests.

(k) "THESL Distribution System" means the system used by THESL for distributing electricity and includes any structures, equipment or other things used for that purpose.

Section 6 – REFERENCES

Schedule B1

Micro-Embedded Generation Facility Connection Agreement

See next 3 pages for terms and conditions

Micro-Embedded Generation Facility Connection Agreement

In consideration of Toronto Hydro agreeing to allow you to connect your 10 kW nameplate rated capacity or smaller generation facility to the Toronto Hydro distribution system, you hereby agree to the following terms and conditions.

1.0 Eligibility

1.1 You agree that your generation connection shall be subject to all applicable laws and bound by the terms and conditions of the Toronto Hydro Conditions of Service, which have been filed with the OEB and are available on request.

2.0 Technical Requirements

2.1 You represent and warrant that you have installed or will install prior to the connection of your generation facility to the Toronto Hydro distribution system, an isolation device satisfying Section 84 of the Ontario Electrical Safety Code, located outside typically near the meter, and agree to the Toronto Hydro staff operation of this as required for the maintenance and repair of the distribution system.

2.2 You agree to perform regular scheduled maintenance to your generation facility as outlined by the manufacturer in order to assure that connection devices, protection systems, and control systems are maintained in good working order and in compliance with all applicable laws.

2.3 You agree that during a power outage on the Toronto Hydro system your generation facility will shut down, unless you have installed special transfer and isolating capabilities on your generation facility. You agree to the automatic disconnection of your generation facility from the Toronto Hydro distribution system, as per the generator protective relay settings set out in this Agreement, in the event of a power outage on the Toronto Hydro distribution system or any abnormal operation of the Toronto Hydro distribution system.

2.4 You covenant and agree that the design, installation, maintenance, and operation of your generation facility are conducted in a manner that ensures the safety and security of both the generation facility and the Toronto Hydro distribution system.

2.5 2.5 Due to the Toronto Hydro obligation to maintain the safety and reliability of its distribution system, you acknowledge and agree that in the event Toronto Hydro determines that your generation facility (i) causes damage to; and/or (ii) is producing adverse effects affecting other distribution system customers or the Toronto Hydro assets, you will disconnect your generation facility immediately from the distribution system upon direction from the Toronto Hydro distribution system and correct the problem at your own expense prior to reconnection.

3.0 Liabilities

3.1 You and Toronto Hydro will save each other harmless for all damages and/or adverse effects resulting from either party's negligence or willful misconduct in the connection and operation of your generation facility or the Toronto Hydro distribution system.

3.2 Toronto Hydro and you shall not be liable to each other under any circumstances whatsoever for any loss of profits or revenues, business interruptions losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

4.0 Compensation and Billing

4.1 If you are not an embedded retail generator, you agree that, subject to any applicable law:

a. The Toronto Hydro will not pay you for any excess generation that results in a net delivery to the Toronto Hydro between meter reads; and

b. There will be no carryover of excess generation from one billing period to the next unless you are, at the relevant time, a net-metered generator.

4.2 If you are an embedded retail generator selling output from the embedded generation facility to the Ontario Power Authority under contract, you agree that the Toronto Hydro will pay you for generation in accordance with the Retail Settlement Code.

4.3 If you are an embedded retail generator delivering and selling output to the Toronto Hydro, you agree that the Toronto Hydro will pay you for generation in accordance with the Retail Settlement Code.

5.0 Termination

5.1 You understand that you have the right to terminate this agreement at any time, and that by doing so you are required to disconnect your generation facility and notify Toronto Hydro of such action.

6.0 Assignment

6.1 You may assign your rights and obligations under this Agreement with the consent of Toronto Hydro, which shall not withhold its consent unreasonably. Toronto Hydro shall have the right to assign its rights and obligations under this Agreement without your consent.

I understand, accept and agree to comply with and be bound by the above terms and conditions governing the connection of my generation facility to the Toronto Hydro distribution system.

Customer Signature: _____ Date: _____

Print Name: _____ Your Hydro Account Number: _____

I confirm that the following information is true and accurate:

Nameplate rating of Generator: _____KW Total installed generation _____KW

Type: ☐ Wind Turbine ☐ Photovoltaic (Solar) ☐ Hydraulic Turbine ☐ Fuel Cell
☐ Other _____

Inverter Utilized: ☐ Yes ☐ No
Inverter Certification: ☐ C22.2 #107.1 ☐ UL 1741 ☐ Site Certified by the ESA

For office use: Station _____ Feeder_____ Date Connected_____

Generator Protective Relay Settings

Table 1 – Inverter Based Generation
The following relay settings shall be used for inverters built to the CSA standard:
Source: CSA C22.2 No. 107.1-01 Table 16

System Voltage Vn = V nominal **V (Volts)**	Frequency **F (Hertz)**	Maximum number of cycles to disconnect	
		Seconds	Cycle
V < 0.5 Vn	60	0.1	6
0.5 Vn • •**V** < 0.88 Vn	60	2	120
1.10 Vn • •**V** <1.37 Vn	60	2	120
V • •1.37 Vn	60	0.033	2
Vn	**F** < 59.5*	0.1	6
Vn	**F** > 60.5	0.1	6

* The UL1741 & IEEE P1547 Standards use F < rated-0.7 i.e. 59.3 Hz. To update if CSA C22.2 No. 107.1-01 is changed

Table 2 – Non – Inverter Generation
Toronto Hydro's minimum requirements, for other generation are as follows:

System Voltage Vn =V nominal **V (Volts)**	Frequency **F (Hertz)**	Maximum clearing time*	
		Seconds	Cycles
V < 0.5 Vn	60	0.16	9.6
0.5 Vn • •**V** < 0.88 Vn	60	2	120
1.10 Vn • •**V** <1.20 Vn	60	1	60
V • •1.20 Vn	60	0.16	9.6
Vn	**F** < 59.3	0.16	9.6
Vn	**F** > 60.5	0.16	9.6

*Clearing time is the time between the start of the abnormal condition and the generation ceasing to energize the Toronto Hydro distribution system

_ If you are uncertain about your generation equipment's protective relay settings, please check with your generating equipment supplier.

_ Automatic reconnect setting time for your generator is after 5 minutes of normal voltage and frequency on the Toronto Hydro distribution system.

Section 6 – REFERENCES

Schedule B2

Form of Connection Agreement for a Small Embedded Generation Facility or a Mid-Sized Embedded Generation Facility

See next 24 pages for terms and conditions

FORM OF CONNECTION AGREEMENT FOR A SMALL EMBEDDED GENERATION FACILITY OR A MID-SIZED EMBEDDED GENERATION FACILITY

This Connection Agreement is made this _____ day of _____, _____.

BETWEEN

_____, (the “Distributor”)

AND

_____, (the “Customer”)

(each a “Party” and collectively the “Parties”)

RECITALS

WHEREAS the Distributor is the owner of the distribution system serving the service area described in electricity distribution licence number _____ *[insert licence number]* (the “Licence”) issued by the Ontario Energy Board (the “Board”) (the "Distributor’s distribution system").

AND WHEREAS the Customer owns or operates an embedded generation facility that is located in the Distributor’s licensed service area (the "Facility").

AND WHEREAS the Customer has connected or wishes to connect its Facility to the Distributor’s distribution system and the Distributor has connected or has agreed to connect the Facility to the Distributor's distribution system.

AND WHEREAS the Distributor has previously reviewed and accepted the Customer's application to connect and related materials that were submitted to the Distributor in accordance with the process set out in the Distribution System Code (the "Code") (altogether, the "Application") and the Distributor and the Customer have signed a connection cost agreement (both of which are attached to this Agreement as Schedule A).

AND WHEREAS in accordance with its Licence and the Code, the Distributor has agreed to offer, and the Customer has agreed to accept, distribution service in relation to the Facility.

NOW THEREFORE in consideration of the foregoing, and of the mutual covenants, agreements, terms and conditions herein contained, the Parties, intending to be legally bound, hereby agree as follows:

1. Definitions and Schedules

1.1 Words and phrases contained in this Agreement (whether capitalized or not) that are not defined in this Agreement have the meanings given to them in the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, any regulations made under either of those *Acts*, or the Code.

1.2 The following schedules form part of this Agreement:

Schedule A – Application and Connection Cost Agreement (recitals)

Schedule B – Single Line Diagram, Connection Point and Location of Facilities (section 2.3)

Schedule C – List of Other Contracts (section 3.4)

Schedule D – Technical and Operating Requirements (section 4.1(d))

Schedule E – Billing and Settlement Procedures (section 5.3)

Schedule F – Contacts for Notice (section 12.1)

Schedule G – Dispute Resolution (section 16.1)

Schedule H – Provisions Applicable if Facility Financed by a Lender (sections 19.3, 20.3 and 21.1)

Where a schedule is to be completed by the Parties, the Parties may not include in that schedule a provision that would be contrary to or inconsistent with the Code or the remainder of this Agreement.

2. Type of Facility and Customer

2.1 The Facility has a name-plate rated capacity of:
[Parties to check the applicable box below]

☐ more than 10 kW and:

(a) up to and including 500 kW, if the Facility is or will be connected to a less than 15 kV line; or

(b) up to and including 1 MW, if the Facility is or will be connected to a 15 kV or greater line

(in which case the Facility is a “Small Embedded Generation Facility”)

☐ 10 MW or less and:

(a) more than 500 kW, if the Facility is or will be connected to a less than 15 kV line; or

(b) more than 1 MW, if the Facility is or will be connected to a 15 kV or greater line

(in which case the Facility is a "Mid-sized Embedded Generation Facility")

2.2 The Facility is or will be connected:

[Parties to check the applicable box(es) below]

☐ directly to the Distributor's distribution system

☐ on the load customer side of a connection point to the Distributor's distribution system

☐ the load customer is the same as the Customer

☐ the load customer is: _____

2.3 Schedule B sets out the following:

(a) a single line diagram of the Facility;
(b) a list of the facilities of one Party that are on the property of the other Party; and
(c) a diagram of the metering installations applicable to the Facility.

2.4 The Customer:

[Parties to check the applicable box(es) below]

☐ intends to:

☐ sell output from the Facility to the Ontario Power Authority and has entered into an agreement with the Ontario Power Authority for that purpose

☐ deliver and sell output from the Facility to the Distributor

(in which case the Customer is an “Embedded Retail Generator”)

☐ does not intend to sell any of the output of the Facility to the Ontario Power Authority or the Distributor

3. Incorporation of Code and Application of Conditions of Service and Other Contracts

3.1 The Code, as it may be amended from time to time, is hereby incorporated in its entirety by reference into, and forms part of, this Agreement. Unless the context otherwise requires, all references to “this Agreement” include a reference to the Code.

3.2 The Distributor hereby agrees to be bound by and at all times to comply with the Code, and the Customer acknowledges and agrees that the Distributor is bound at all times to comply with the Code in addition to complying with the provisions of this Agreement.

3.3 In addition to this Agreement, the relationship between the Distributor and the Customer will be governed by the Distributor’s Conditions of Service that are in effect at the relevant time. In the event of a conflict or an inconsistency between a provision of this Agreement and a provision of the Distributor’s Conditions of Service, the provision of this Agreement shall govern.

3.4 The Distributor may require or may have already required the Customer to enter into one or more of the other contracts listed in Schedule C. In the event of a conflict or an inconsistency between a provision of the Code or this Agreement and a provision of such other contract, the provision of the Code or this Agreement shall govern.

4. Facility Standards

4.1 The Customer shall ensure that the Facility:

(a) meets all applicable requirements of the Electrical Safety Authority (“ESA”);
(b) conforms to all applicable industry standards including, but not limited to, those of the Canadian Standards Association (“CSA”), the Institute of Electrical and Electronic Engineers, the American National Standards Institute and the International Electrotechnical Commission;
(c) is installed, constructed, operated and maintained in accordance with this Agreement, the Distributor’s offer to connect, the requirements of the ESA, the connection cost agreement, all applicable reliability standards and good utility practice; and
(d) meets the technical and operating requirements set out in Schedule D. These requirements shall not exceed any technical or operating requirements set out in the Code unless the Customer agrees.

5. Charges, Settlement and Billing

5.1 The Customer shall pay the Distributor such charges as may be approved by the Board in relation to the connection of, and the provision of distribution service to, the Facility.

5.2 The Customer agrees to the following in relation to settlement for the output of the Facility:
[Parties to check the applicable box below]

☐ if the Customer is not an Embedded Retail Generator (see section 2.4)
the Distributor will not pay the Customer for any excess generation that results in a net delivery to the Distributor between meter reads and there will be no carryover of excess generation from one billing period to the next unless the Customer is at the relevant time a net metered generator

☐ if the Customer is an Embedded Retail Generator (see section 2.4)
the Distributor will settle all applicable payments and charges in accordance with the Retail Settlement Code

5.3 Billing and settlement activities will be conducted in accordance with the procedures set out in Schedule E.

6. Representations and Warranties

6.1 The Customer represents and warrants to the Distributor as follows, and acknowledges that the Distributor is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) the Facility is fully and accurately described in the Application;
(b) all information in the Application is true and correct;
(c) the Facility is in compliance with all applicable technical requirements and laws;
(d) the Customer has been given warranty information and operation manuals for the Facility;
(e) the Customer has been adequately instructed in the operation and maintenance of the Facility and the Customer has developed and implemented an operation and maintenance plan based on those instructions;
(f) if the Customer is a corporation or other form of business entity, the Customer is duly incorporated, formed or registered (as applicable)

under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(g) the Customer has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations under this Agreement;

(h) this Agreement constitutes a legal and binding obligation on the Customer, enforceable against the Customer in accordance with its terms;

(i) the Customer holds all permits, licences and other authorizations that may be necessary to enable it to own and operate the Facility; and

(j) any individual signing this Agreement on behalf of the Customer has been duly authorized by the Customer to sign this Agreement and has the full power and authority to bind the Customer.

6.2 The Distributor represents and warrants to the Customer as follows, and acknowledges that the Customer is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) the Distributor is duly incorporated under the laws of Ontario;

(b) the Distributor has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations under this Agreement;

(c) this Agreement constitutes a legal and binding obligation on the Distributor, enforceable against the Distributor in accordance with its terms; and

(d) any individual signing this Agreement on behalf of the Distributor has been duly authorized by the Distributor to sign this Agreement and has the full power and authority to bind the Distributor.

7. Disconnection Device at the Point of Connection

7.1 The Customer shall furnish and install a disconnection switch at the point of connection for the Facility that opens, with a visual break, all ungrounded poles of the connection circuit. The disconnection switch at the point of connection shall be rated for the voltage and fault current requirements of the Facility, and shall meet all applicable CSA standards, ESA requirements, and all other applicable laws. The switch enclosure, if applicable, shall be properly grounded. The disconnection switch at the point of connection shall be accessible at all times, located for ease of access to the Distributor's personnel, and shall be capable of being locked in the open position. The Customer shall follow the Distributor's procedures for switching, clearance, tagging, and locking.

8. Modifications to the Facility

8.1 The Customer shall not modify its connection assets or the Facility except in accordance with this section. Where the modification will not increase the

maximum electrical output of the Facility, the Customer shall give the Distributor no less than 15 working days notice prior to the date on which the modification will be completed. Where the modification will increase the maximum electrical output of the Facility, the Customer shall submit a new application for connection to the Distributor. The Distributor shall process that application for connection in accordance with the Code. The Customer shall not commence such modification until that process has been completed.

9. Insurance

9.1 Throughout the term of this Agreement, the Customer shall carry commercial general liability insurance for third party bodily injury, personal injury, and property damage in an amount as follows:

[Parties to check the applicable box below]

☐ if the Facility is a Small Embedded Generation Facility (see section 2.1)

not less than $1,000,000 per occurrence and in the annual aggregate

☐ if the Facility is a Mid-sized Embedded Generation Facility (see section 2.1)

not less than $2,000,000 per occurrence and in the annual aggregate

Prior to execution of this Agreement, the Customer shall provide the Distributor with a valid certificate of insurance. The Customer shall provide the Distributor with prompt notice of any cancellation of the Customer's insurance by the insurer.

10. Liability and Force Majeure

10.1 The liability provisions of section 2.2 of the Code apply to this Agreement and are hereby incorporated by reference into, and form part of, this Agreement.

10.2 A Party shall have a duty to mitigate any losses relating to any claim for indemnification from the other Party that may be made in relation to that other Party. Nothing in this section shall require the mitigating Party to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

10.3 A Party shall give prompt notice to the other Party of any claim with respect to which indemnification is being or may be sought under this Agreement.

10.4 The force majeure provisions of section 2.3 of the Code apply to this Agreement and are hereby incorporated by reference into, and form part of, this Agreement.

11. Facility Commissioning and Testing

11.1 The Customer shall give the Distributor at least fifteen days advance written notice of the date(s) and time(s) on which the Facility will be commissioned and tested prior to connection. The Customer shall give the Distributor the same notice in relation to the commissioning and testing of any material modification to the Customer's connection assets or Facility that occurs after connection.

11.2 The Distributor shall have the right to witness the commissioning and testing activities referred to in section 11.1.

12. Notice

12.1 Any notice, demand, consent, request or other communication required or permitted to be given or made under or in relation to this Agreement shall be given or made: by courier or other personal form of delivery; by registered mail; by facsimile; or by electronic mail. Notices shall be addressed to the applicable representative of the Party identified in Schedule F.

12.2 A notice, demand, consent, request or other communication referred to in section12.1 shall be deemed to have been made as follows:

(a) where given or made by courier or other form of personal delivery, on the date of receipt;
(b) where given or made by registered mail, on the sixth day following the date of mailing;
(c) where given or made by facsimile, on the day and at the time of transmission as indicated on the sender's facsimile transmission report; and
(d) where given or made by electronic mail, on the day and at the time when the notice, demand, consent, request or other communication is recorded by the sender=s electronic communications system as having been received at the electronic mail destination.

13. Access to Facility

13.1 Each Party shall ensure that its facilities are secured at all times.

13.2 The Customer shall permit and, if the land on which the Facility is located is not owned by Customer, cause such landowner to permit, the Distributor's employees and agents to enter the property on which the Facility is located at any reasonable time. Such access shall be provided for the purposes of

inspecting and/or testing the Facility as and when permitted by this Agreement, the Code or the Distributor's Conditions of Service or as required to ensure the continued safe and satisfactory operation of the Facility, to ensure the accuracy of the Distributor's meters, to establish work protection, or to perform work.

13.3 Any inspecting and/or testing referred to in section 13.2 shall not relieve the Customer from its obligation to operate and maintain the Facility and any related equipment owned by the Customer in a safe and satisfactory operating condition and in accordance with this Agreement.

13.4 The Distributor shall have the right to witness any testing done by the Customer of the Facility and, to that end, the Customer shall provide the Distributor with at least fifteen working days advance notice of the testing.

13.5 Notwithstanding section 10.1, where the Distributor causes damage to the Customer's property as part of this access, the Distributor shall pay to the Customer the Customer's reasonable costs of repairing such property or, if such property cannot be repaired, replacing such property.

13.6 Notwithstanding section 10.1, if the Customer has been given access to the Distributor's property, and if the Customer causes damage to the Distributor's property as part of that access, the Customer shall pay to the Distributor the Distributor's reasonable costs of repairing such property or, if such property cannot be repaired, replacing such property.

14. Disconnection of Facility to Permit Maintenance and Repairs

14.1 If the Customer requests it, the Distributor will provide the Customer with reasonable notice of any planned equipment outages in the Distributor's distribution system that occur on or after the date of the Customer's request which will impact the Facility or its connection.

14.2 The Distributor will make reasonable efforts to ensure that the outages referred to in section 14.1 will be of minimal duration and cause minimal inconvenience to the Customer.

14.3 In connection with any planned equipment outage, either Party may disconnect or isolate, or require the disconnection or isolation of, its Facility or system (as applicable) from the other Party's Facility or system (as applicable) so that the employees, contractors or agents of the Party may construct, maintain, repair, replace, remove, investigate or inspect its own Facility or system (as applicable) in accordance with the terms of this Agreement and good utility practice.

14.4 Where practical, the Customer shall notify the Distributor prior to temporarily isolating or disconnecting the Facility from the Distributor's distribution system.

15. Disconnection of Facility for Other Reasons

15.1 The Customer shall discontinue operation of the Facility and the Distributor may isolate or disconnect the Facility from the Distributor's distribution system, upon any of the following:

(a) termination of this Agreement in accordance with section 19;
(b) if the Customer's connection assets or the Facility are modified by the Customer in a manner contrary to section 8.1;
(c) during an emergency or where necessary to prevent or minimize the effects of an emergency;
(d) in accordance with section 31, 31.1 or 40(5) of the *Electricity Act, 1998*, other applicable law, the Code, the Distributor's Licence or the Distributor's Conditions of Service; or
(e) where required to comply with a decision or order of an arbitrator or court made or given under Schedule G.

15.2 In the event of disconnection under section 15.1(b), the Facility shall remain isolated or disconnected from the Distributor's distribution system until the connection process referred to in section 8.1 has been completed.

15.3 In the event of disconnection under section 15.1(c), the Distributor shall reconnect, or permit the reconnection of, the Facility to the Distributor's distribution system when it is reasonably satisfied that the emergency has ceased and that all other requirements of this Agreement are met.

15.4 In the event of disconnection under section 15.1(d) or 15.1(e), the Distributor shall reconnect, or permit the reconnection of, the Facility to the Distributor's distribution system when the Distributor is reasonably satisfied that the reason for the disconnection no longer exists, the Customer agrees to pay all Board-approved reconnection costs charged by the Distributor, and the Distributor is reasonably satisfied of the following, where applicable:

(a) the Customer has taken all necessary steps to prevent the circumstances that caused the disconnection from recurring and has delivered binding undertakings to the Distributor that such circumstances shall not recur; and
(b) any decision or order of a court or arbitrator made or given under Schedule G that requires a Party to take action to ensure that such circumstances shall not recur has been implemented and/or assurances have been given to the satisfaction of the affected Party that such decision or order will be implemented.

15.5 Where the Facility has been isolated or disconnected, each Party shall be entitled to decommission and remove its assets associated with the connection. Each Party shall, for that purpose, ensure that the other Party has all necessary access to its site at all reasonable times.

15.6 The Customer shall continue to pay for distribution services provided up to the time of isolation or disconnection of its Facility.

15.7 The Customer shall pay all reasonable costs including, but not limited to, the costs of removing any of the Distributor's equipment from the Customer's site, that are directly attributable to the isolation or disconnection of the Facility and, where applicable, the subsequent decommissioning of the Facility. The Distributor shall not require the removal of the protection and control wiring on the Customer's site.

15.8. While the Facility is isolated or disconnected, the Distributor shall not be required to convey electricity to or from the Facility.

16. Dispute Resolution

16.1 Any dispute between the Customer and the Distributor arising under or in relation to this Agreement will be resolved in accordance with Schedule G. The Parties shall comply with the procedure set out in Schedule G before taking any civil or other proceeding in relation to the dispute, provided that nothing shall prevent a Party from seeking urgent or interlocutory relief from a court of competent jurisdiction in the Province of Ontario in relation to any dispute arising under or in relation to this Agreement.

17. Amendments

17.1. The Parties may not amend this Agreement without leave of the Board except where and to the extent permitted by this Agreement.

17.2. The Parties may by mutual agreement amend this Agreement to reflect changes that may from time to time be made to the Code during the term of this Agreement.

17.3. The Parties may by mutual agreement amend any portion of a schedule that was originally to be completed by the Parties.

17.4 No amendment made under section 17.2 or 17.3 shall be contrary to or inconsistent with the Code or the remainder of this Agreement.

17.5 The Parties shall amend this Agreement in such manner as may be required by the Board.

17.6 Any amendment to this Agreement shall be made in writing and duly executed by both Parties.

18. Waiver

18.1 A waiver of any default, breach or non-compliance under this Agreement is not effective unless in writing and signed by the Party to be bound by the waiver. The waiver by a Party of any default, breach or non-compliance under this Agreement shall not operate as a waiver of that Party's rights under this Agreement in respect of any continuing or subsequent default, breach or non-compliance, whether of the same or any other nature.

19. Term of Agreement and Termination

19.1 This Agreement shall become effective upon execution by the Parties, and shall continue in effect until terminated in accordance with section 19.2 or 19.3.

19.2 The Customer may, if it is not then in default under this Agreement, terminate this Agreement at any time by giving the Distributor thirty days prior written notice setting out the termination date.

19.3 Except as set out in Schedule H, the Distributor may terminate this Agreement upon any material breach of this Agreement by the Customer (a "Default"), if the Customer fails to remedy the Default within the applicable cure period referred to in section 19.4 after receipt of written notice of the Default from the Distributor.

19.4 The Customer shall cure a Default within the applicable cure period specified in the Code or the Distributor's Conditions of Service. If no such cure period is specified in relation to a given Default, the cure period shall be sixty working days.

19.5 Termination of this Agreement for any reason shall not affect:

(a) the liabilities of either Party that were incurred or arose under this Agreement prior to the time of termination; or
(b) the provisions that expressly apply in relation to disconnection of the Customer's facilities following termination of this Agreement.

19.6 Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it including, but not limited to, injunctive relief.

19.7 The rights and remedies set out in this Agreement are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to a Party at law or in equity. Nothing in this

section 19.7 shall be interpreted as affecting the limitations of liability arising from section 10.1 or the obligation of a Party to comply with section 16 while this Agreement is in force.

19.8 Sections 19.5 to 19.7 shall survive termination of this Agreement.

20. Exchange and Confidentiality of Information

20.1 Confidential information in respect of a Party means (i) information disclosed by that Party to the other Party under this Agreement that is in its nature confidential, proprietary or commercially sensitive and (ii) information derived from the information referred to in (i), but excludes the following:

(a) information that is in the public domain; or
(b) information that is, at the time of the disclosure, in the possession of the receiving Party, provided that it was lawfully obtained from a person under no obligation of confidence in relation to the information.

20.2 Subject to section 20.3, each Party shall treat all confidential information disclosed to it by the other Party as confidential and shall not, without the written consent of that other Party:

(a) disclose that confidential information to any other person; or
(b) use that confidential information for any purpose other than the purpose for which it was disclosed or another applicable purpose contemplated in this Agreement.

Where a Party, with the written consent of the other Party, discloses confidential information of that other Party to another person, the Party shall take such steps as may be required to ensure that the other person complies with the confidentiality provisions of this Agreement.

20.3 Nothing in section 20.2 shall prevent the disclosure of confidential information:

(a) where required or permitted under this Agreement, the Code, the Market Rules or the Distributor's Licence;
(b) where required by law or regulatory requirements;
(c) where required by order of a government, government agency, regulatory body or regulatory agency having jurisdiction;
(d) if required in connection with legal proceedings, arbitration or any expert determination relating to the subject matter of this Agreement, or for the purpose of advising a Party in relation thereto;
(e) as may be required to enable the Distributor to fulfill its obligations to any reliability organization; or

(f) as may be required during an emergency or to prevent or minimize the effects of an emergency.

20.4 Notwithstanding section 10.1, a Party that breaches section 20.2 shall be liable to the other Party for any and all losses of the other Party arising out of such breach.

20.5 The Parties agree that the exchange of information, including, but not limited to, confidential information, under this Agreement is necessary for maintaining the reliable operation of the Distributor's distribution system. The Parties further agree that all information, including, but not limited to, confidential information, exchanged between them shall be prepared, given and used in good faith and shall be provided in a timely and cooperative manner.

20.6 Each Party shall provide the other with such information as the other may reasonably require to enable it to perform its obligations under this Agreement.

20.7 Each Party shall, as soon as practicable, notify the other Party upon becoming aware of a material change or error in any information previously disclosed to the other Party under this Agreement and, in the case of the Customer, in any information contained in its Application. The Party shall provide updated or corrected information as required to ensure that information provided to the other Party is up to date and correct.

21. Assignment, Successors and Assigns

21.1 Except as set out in Schedule H, the Customer shall not assign its rights or obligations under this Agreement in whole or in part without the prior written consent of the Distributor, which consent shall not be unreasonably withheld or unduly delayed. The Distributor may withhold its consent to any proposed assignment until the proposed assignee assumes, in writing, all of the Customer's obligations contained in this Agreement.

21.2 The Distributor shall have the right to assign this Agreement in whole upon written notification to the Customer.

21.3 This Agreement shall be binding upon and enure to the benefit of the Parties and their respective successors and permitted assigns.

22. Governing Law

22.1. This Agreement shall be governed by the laws of the Province of Ontario and the federal laws of Canada applicable therein.

23. Entire Agreement

23.1 Except as expressly provided herein, this Agreement constitutes the entire agreement between the Parties with respect to the subject-matter hereof and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the subject-matter hereof.

IN WITNESS WHEREOF, the Parties hereto, intending to be legally bound, have caused this Agreement to be executed by their duly authorized representatives.

_____ _____
Customer Signature Date

_____
Name (Print)

_____
Title

_____ _____
Distributor Signature Date

_____
Name (Print)

_____
Title

SCHEDULE A

Application and Connection Cost Agreement (recitals)

See the attached Application and connection cost agreement.

[To be attached by the Parties]

SCHEDULE B

Single Line Diagram, Connection Point and Location of Facilities (section 2.3)

B.1 Single Line Diagram and Connection Point

[To be inserted by the Parties]

B.2 List of Facilities on the Property of the Other Party

B.2.1 The following facilities of the Customer are located on the property of the Distributor:

[To be completed by the Parties]

B.2.2 The following facilities of the Distributor are located in the property of the Customer:

[To be completed by the Parties]

B.3 Metering Installation Diagram

[To be inserted by the Parties]

SCHEDULE C

List of Other Contracts (section 3.4)

The following other contracts have been or will be entered into by the Parties:

[To be completed by the Parties]

SCHEDULE D

Technical and Operating Requirements (section 4.1(d))

The following technical and operating requirements apply to the Facility:

[To be completed by the Parties]

SCHEDULE E

Billing and Settlement Procedures (section 5.3)

The following provisions apply in relation to billing and settlement in relation to the Facility:

[To be completed by the Parties]

SCHEDULE F

Contacts for Notice (section 12.1)

[To be completed by the Parties – different contacts may be listed for different purposes]

SCHEDULE G

Dispute Resolution (section 16.1)

G.1 The Party claiming a dispute will provide written notice to the other Party. The Parties will make reasonable efforts through or by their respective senior executives to resolve any dispute within sixty days of receipt of such notice.

G.2 If a dispute is settled by the senior executives of the Parties, the Parties shall prepare and execute minutes setting forth the terms of the settlement. Such terms shall bind the Parties. The subject-matter of the dispute shall not thereafter be the subject of any civil or other proceeding, other than in relation to the enforcement of the terms of the settlement. If a Party fails to comply with the terms of settlement, the other Party may submit the matter to arbitration under section G.3. A copy of the minutes referred to in this section from which all confidential information has been expunged shall be made available to the public by the Distributor upon request.

G.3 If the senior executives of the Parties cannot resolve the dispute within the time period set out in section G.1 or such longer or shorter period as the Parties may agree, either Party may submit the dispute to binding arbitration under sections G.4 to G.8 by notice to the other Party.

G.4 The Parties shall use good faith efforts to appoint a single arbitrator for purposes of the arbitration of the dispute. If the Parties fail to agree upon a single arbitrator within ten working days of the date of the notice referred to in section G.3, each Party shall within five working days thereafter choose one arbitrator. The two arbitrators so chosen shall within fifteen working days select a third arbitrator.

G.5 Where a Party has failed to choose an arbitrator under section G.4 within the time allowed, the other Party may apply to a court to appoint a single arbitrator to resolve the dispute.

G.6 A person may be appointed as an arbitrator if that person:

(a) is independent of the Parties;
(b) has no current or past substantial business or financial relationship with either Party, except for prior arbitration; and
(c) is qualified by education or experience to resolve the dispute.

G.7 The arbitrator(s) shall provide each of the Parties with an opportunity to be heard orally and/or in writing, as may be appropriate to the nature of the dispute.

G.8 The *Arbitration Act, 1991* (Ontario) shall apply to an arbitration conducted under this Schedule G.

G.9 The decision of the arbitrator(s) shall be final and binding on the Parties and may be enforced in accordance with the provisions of the *Arbitration Act, 1991* (Ontario). The Party against which the decision is enforced shall bear all costs and expenses reasonably incurred by the other Party in enforcing the decision.

G.10 A copy of the decision of the arbitrator(s) from which any confidential information has been expunged shall be made available to the public by the Distributor upon request.

G.11 Subject to section G.12, each Party shall be responsible for its own costs and expenses incurred in the arbitration of a dispute and for the costs and expenses of the arbitrator(s) if appointed to resolve the dispute.

G.12 The arbitrator(s) may, if the arbitrator(s) consider it just and reasonable to do so, make an award of costs against or in favour of a Party to the dispute. Such an award of costs may relate to either or both the costs and expenses of the arbitrator(s) and the costs and expenses of the Parties to the dispute.

G.13 If a dispute is settled by the Parties during the course of an arbitration, the Parties shall prepare and execute minutes setting forth the terms of the settlement. Such terms shall bind the Parties, and either Party may request that the arbitrator(s) record the settlement in the form of an award under section 36 of the *Arbitration Act, 1991* (Ontario). The subject-matter of the dispute shall not thereafter be the subject of any civil or other proceeding, other than in relation to the enforcement of the terms of the settlement.

G.14 If a Party fails to comply with the terms of settlement referred to in section G.13, the other Party may submit the matter to arbitration under section G.3 if the settlement has not been recorded in the form of an award under section 36 of the *Arbitration Act, 1991* (Ontario).

G.15. A copy of the minutes referred to in section G.13 from which all confidential information has been expunged shall be made available to the public by the Distributor upon request.

G.16 The Parties may not, by means of the settlement of a dispute under section G.2 or section G.13, agree to terms or conditions that are inconsistent with or contrary to the Code or this Agreement.

SCHEDULE H
Provisions Applicable if Facility Financed by a Lender (sections 19.3, 20.3 and 21.1)

H.1 For the purposes of this Schedule, "lender" means a bank or other entity whose principal business in that of a financial institution and that is financing or refinancing the Facility.

H.2 Where notice of a Default has been served on the Customer under section 19.3, an agent or trustee for and on behalf of a lender ("Security Trustee") or a receiver appointed by the Security Trustee ("Receiver") shall upon notice to the Distributor be entitled (but not obligated) to exercise all of the rights and obligations of the Customer under this Agreement and shall be entitled to remedy the Default specified in the notice within the applicable cure period referred to in section 19.4. The Distributor shall accept performance of the Customer's obligations under this Agreement by the Security Trustee or Receiver in lieu of the Customer's performance of such obligations, and will not exercise any right to terminate this Agreement under section 19.3 due to a Default if the Security Trustee, its nominee or transferee, or the Receiver acknowledges its intention to be bound by the terms of this Agreement and such acknowledgment is received within 30 days of the date of receipt by the Customer of the notice of Default.

H.3 The Customer may, without the prior written consent of the Distributor, assign by way of security only all or any part of its rights or obligations under this Agreement to a lender. The Customer shall promptly notify the Distributor upon making any such assignment.

H.4 The Customer may disclose confidential information of the Distributor to a lender or a prospective lender.

Section 6 – REFERENCES

Schedule B3

Connection Agreement for an Embedded Generation Facility Greater than 10 MW

See next 31 pages for terms and conditions

CONNECTION AGREEMENT
FOR AN EMBEDDED GENERATION FACILITY GREATER THAN 10 MW

TERMS AND CONDITIONS

ARTICLE 1: CONNECTION

1.1 The Embedded Generation Facilities shall be connected to the THESL Distribution System and remain Energized at the Point of Connection from the Connection Date for the duration of the Term on the terms and subject to the conditions set out in this Agreement.

ARTICLE 2: POINT OF CONNECTION AND JURISDICTION

2.1 The point of delivery and connection for the Embedded Generation Facilities located at the Site shall be where the THESL supply feeders connects to the high voltage disconnect switches (the "Point of Connection") or such other points as may be designated by THESL.

2.2 THESL shall have jurisdiction over and control of the area between the point of entry of THESL supply feeders onto the Customer's property at the Site and the load side of the Customer-owned switchgear, including:

(i) the electrical interlocks for the closed operations of the circuit breakers to ensure the non-paralleling of the supply feeder; and
(ii) THESL revenue billing metering equipment;

or such areas as may be designated by THESL.

ARTICLE 3: COVENANTS OF THE CUSTOMER

3.1 The Embedded Generation Facilities, when inter-connected to the THESL system, shall not adversely affect or damage:

(a) the health and safety of THESL or any of its Representatives or the general public;
(b) the Apparatus owned or operated by THESL;
(c) the THESL Distribution System;
(d) the security, safety, or reliability of the THESL Distribution System;
(e) in a material manner, the efficiency of the THESL Distribution System; or
(f) in a material manner the quality of the electrical power supply provided by THESL to the Customer or other THESL customers.

3.2 The Customer shall, at its expense, maintain any and all permits, licenses and approvals required by law for the operation and maintenance of the Embedded Generation Facilities ("Required Approvals") throughout the Term.

3.3 The Customer shall (i) pay THESL for all electricity distribution services provided by THESL to the Site during the Term at such rates as may be approved by the Ontario Energy Board ("OEB") from time to time for the appropriate class rating to which the services apply; (ii) pay in a timely manner such other payments as it may agree with THESL including standby and other charges; (iii) make such payments in accordance with THESL's billing cycle as notified to the Customer from time to time; and (iv) pay late payment and other charges and pay such deposits as may be required by THESL from time to time as part of the OEB-approved rate structure. The Customer shall also pay to THESL such other charges as THESL may be required by applicable law to bill and/or collect for third parties including electricity retailers, the Independent Market Operator, Ontario Energy Board and any transmission company.

3.4 The Customer shall not, in installing, operating or maintaining the Embedded Generation Facilities:

(a) violate, or cause THESL to violate, any provision of its Distribution License;

(a) contravene any laws of the Province of Ontario or any laws of Canada having force and effect in the Province of Ontario; or

(b) violate any provision contained in the Conditions of Service.

3.5 The Customer shall comply as soon as possible with any directive received from THESL that THESL makes for the purpose of meeting any of its obligations under its Distribution License.

3.6 The Customer shall construct, maintain and operate the Embedded Generation Facilities in such a manner that THESL does not incur operating costs as a result of the connection with the Customer which exceed the revenues received in respect of the connection with the Customer.

3.7 In addition to the obligations set forth in this Agreement, the Customer shall be bound by, and shall comply with, all provisions of THESL's Conditions of Service.

3.8 The Customer shall prepare and deliver to THESL, from time to time, or upon request from THESL, a plan for regularly scheduled maintenance to ensure that all parts of the Embedded Generation Facilities, including, connection devices and protection and control systems are maintained in good working order. THESL shall review the proposed maintenance plan to ensure that it complies with the Distribution System Code and the Conditions of Service and otherwise meets the level of standards, procedures and instructions set by THESL from time to time, which shall include, without limitation, the following standards, procedures and instructions:

(a) only Competent Persons may carry out inspections, repairs and maintenance;

(b) periodic tests must be performed on each protection system to verify that the system operates as designed and testing intervals for each protection system should not exceed four years for microprocessor - based systems and 2 years for electro-mechanical based systems;

(c) a visual inspection of the generator facility at least once a year to note obvious maintenance problems such as broken insulators or other damaged equipment;

(d) a plan for any deficiencies identified during inspections to be noted and repaired as soon as possible having regard to the severity of the problem, due diligence concerns of THESL and the Customer and financial and material requirements;

(e) delivery to THESL, prior to the first inspection or upon request, a list of all critical protective and/or interlocking equipment;

(f) immediate notification to THESL of any deficiencies involving critical protective equipment; and

(g) delivery to THESL of all relevant inspection and repair reports that may effect the protection and performance of THESL Distribution System.

The Customer will maintain the Embedded Generation Facilities in accordance with the maintenance plan and otherwise in a manner consistent with Good Utility Practice.

3.9 The Customer shall limit the effects of harmonic voltages and currents on the THESL Distribution System caused by the Embedded Generation Facilities in accordance with the IEEE specification 519-1992 titled "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems". In the event THESL, in its discretion, deems it necessary for modifications to be made to the Embedded Generation Facilities to achieve acceptable power quality, the Customer shall make such modifications, at its own cost, within such time period as is specified by THESL, acting reasonably; provided that if the modifications are not completed within that time period, THESL shall be entitled to disconnect the Embedded Generation Facilities from the THESL Distribution System without any further notice and the provisions of Section 5.4 shall apply.

3.10 The Customer shall provide and install before the performance of any of the Tests under this Agreement, and maintain, at its cost, all protective, interlocking and isolating devices deemed necessary by THESL, in its sole discretion, to allow for the safe interconnection, disconnection,

isolation and emergency operation of the Embedded Generation Facilities.

3.11 THESL shall be entitled to access to the property of the Customer at all reasonable times, to inspect, maintain, repair, alter, remove, replace or disconnect wires or other parts of the Embedded Generation Facilities, or to install, inspect, read, calibrate, maintain, repair, alter, remove or replace any meter, which are located on the property and to take any actions necessary to maintain the safe and reliable operation of the THESL Distribution System. The Customer shall also provide THESL with such other access as may be specified in the Conditions of Service, Operating Schedule or by law. In accessing the property of the Customer THESL shall comply with the Customer's reasonable security practices and procedures to the extent they are made aware of such practices and procedures.

The Customer agrees to provide suitable space at the Site for THESL's meters and wires and, where necessary, poles, cables, transformers and other appliances and equipment (collectively "Metering Equipment") and for any Metering Equipment which THESL may be required by law to install at any time after the date of this Agreement and further agrees that without the prior written consent of THESL (not to be unreasonably withheld) it will not permit anyone who is not an agent of THESL to remove, inspect or tamper with same, including moving, inspecting or tampering with any meter seals. The Customer agrees that Representatives of THESL shall have reasonable access to the Site and Embedded Generation Facilities for the purposes of reading, examining, preparing or removing its Metering Equipment and for the purpose of inspecting the Customer's appliances, equipment and wiring.

3.12 The Customer shall comply with and be bound by the provisions of any Operating Schedule which is delivered to the Customer by THESL from time to time and shall operate the Embedded Generation Facilities in accordance with those provisions.

3.13 The Customer shall have no rights of access to any THESL Apparatus or lands or property owned by THESL.

3.14 If, as a consequence of the connection of the Embedded Generation Facilities to the THESL Distribution System or the Tests performed hereunder, (i) damage occurs to the Apparatus owned or operated by THESL ("THESL Apparatus") or the THESL Distribution System, or (ii) THESL incurs increased costs in operating the THESL Distribution System, the Customer shall, within 10 days of receipt of an invoice therefore, pay the amount of any such damage or increased costs to THESL.

3.15 The Customer shall comply with all metering requirements imposed by THESL, acting reasonably from time to time including, if so required by Hydro One, THESL or any regulatory authority in accordance with

applicable laws, at any time, installing at the Customers expense performance metering equipment.

3.16 If the Customer installs performance metering equipment in accordance with Section 3.15, the Customer shall allow THESL to receive output from the performance metering equipment, and the Customer shall install and maintain any equipment necessary to allow THESL to do so, at no cost to THESL.

ARTICLE 4: COSTS

4.1 Any amount to be paid under this Agreement unless otherwise specified, shall become due and owing and be paid by the Customer to THESL 10 days after receipt of an invoice for such amount from THESL.

4.2 Any amount required to be paid under this Agreement, whether for the cost of the Tests or otherwise, which is not paid on the due date therefore, shall bear interest at the rate 12 percent per annum at and from the due date up to and including the date of payment in full of such amount, together with all interest accrued to the date of payment.

ARTICLE 5: TERM AND TERMINATION

5.1 Unless terminated earlier in accordance with the terms of this Agreement, this Agreement shall be effective as of the date first written above and shall continue in full force and effect until either party gives no less than 365 days written notice to the other party of its intention to terminate this Agreement (the "Term"). Any such notice of termination shall specify the effective date of termination; provided that notwithstanding the delivery of a notice of termination under this Section 5.1, THESL shall have the right to terminate this Agreement prior to the specified effective date of termination pursuant to Section 5.2 or any other provision of this Agreement allowing for termination.

5.2 The occurrence of any of the following shall constitute an event of default ("Event of Default") on the part of the defaulting party:

(a) failure to pay any sum due and owing hereunder including any sum owing pursuant to Section 3.3 within 5 days of receipt of a notice of failure to pay;

(b) failure to comply with any other material covenant or obligation set forth in this Agreement within 14 days receipt of notice of default from the non-defaulting party; or

(c) the occurrence of a material breach or default under any other agreement which the Customer has with THESL.

5.3 (a) Upon the occurrence of an Event of Default, where the Customer is the defaulting party ("Customer Event of Default") THESL shall have the right to:

(i) give notice of termination to the Customer whereupon the Agreement shall terminate as at the effective date of termination specified in the notice; and

(ii) disconnect the Embedded Generation Facilities from the THESL Distribution System in accordance with Section 6.1 below.

(b) Upon the occurrence of an Event of Default where THESL is the defaulting party ("THESL Event of Default"), the Customer shall have the right to give notice of termination to THESL whereupon the Agreement shall terminate as at the effective date of termination specified in the notice.

5.4 Upon termination of the Agreement the THESL for any reason, without prejudice to any other rights THESL may have:

(a) all amounts outstanding pursuant to this Agreement shall immediately become due and payable by the Customer;

(b) THESL shall be entitled to enter onto the Customer's property to remove, at the Customer's expense, any THESL Apparatus as soon as reasonably practicable;

(c) the relevant provisions of this Agreement shall continue in effect after expiry or termination to the extent necessary to provide for any billings, adjustments and payments related to the period prior to the termination and for the payment of any monies due and owing pursuant to this Agreement;

(d) the termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either party under this Agreement, which are intended to continue after termination of such Agreement, including, without limitation, Article 9; Article 10 and Section 12.3;

(e) subject to termination being in accordance with this Agreement, THESL shall have no liability whatsoever to the Customer arising from such termination; and

(f) THESL may, if it has not already done so, disconnect the Embedded Generation Facilities from the THESL Distribution System.

5.5 Upon termination of the Agreement by Customer in accordance with its provision, without prejudice to any other rights Customer may have:

(a) all amounts outstanding pursuant to this Agreement shall immediately become due and payable by THESL;

(b) the relevant provisions of this Agreement shall continue in effect after expiry or termination to the extent necessary to provide for any billings, adjustments and payments related to the period prior to the termination and for the payment of any monies due and owing pursuant to this Agreement;

(c) the termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either party under this Agreement, which are intended to continue after termination of such Agreement, including, without limitation, Article 9; Article 10 and Section 12.3;

(d) subject to termination being in accordance with this Agreement, the Customer shall have no liability whatsoever to THESL arising from such termination; and

(e) THESL shall, if has not already done so, disconnect the Embedded Generation Facilities from the THESL Distribution System.

ARTICLE 6: DISCONNECTION

6.1 Notwithstanding anything else contained in this Agreement, THESL may disconnect the Embedded Generation Facilities from the THESL Distribution System:

(a) if an Event of Default occurs, upon reasonable prior notice to the Customer; provided that:

(i) THESL may, if it, in its sole discretion acting reasonably, deems it necessary for any reason whatsoever, disconnect the Embedded Generation Facilities from the THESL Distribution System immediately without any notice to the Customer; and

(ii) if the disconnection is as a result of non-payment of monies due and owing hereunder, THESL shall provide no less than 7 days notice of such disconnection;

(b) immediately without notice, if THESL, in its sole discretion, determines it is necessary:

(i) to protect the health or safety of THESL personnel, its contractors or any third parties;
(ii) to prevent damage to the THESL Distribution System or any other property;

(iii) to preserve the security, safety, and reliability of the THESL Distribution System and quality of electrical power and services delivered thereunder;

(iv) to prevent a material adverse effect on the efficiency of the THESL Distribution System or quality of electrical power supply provided by THESL to the Customer or other THESL customers;

(v) as a result of any other circumstances which THESL in its sole discretion, determines to be an Emergency; or

(vi) the Customer has failed to comply with the Ontario Electrical Safety Code;

(c) upon reasonable prior notice to the Customer to perform any unplanned inspections or maintenance;

(d) upon termination of the Agreement pursuant to Section 5.1 or 5.3;

(e) immediately without notice, upon issuance of an order or directive requiring disconnection by any court or regulatory authority having jurisdiction over disconnection; or

(f) for any other reason specified in this Agreement or the Conditions of Service.

6.2 If THESL exercises any rights to disconnect the Embedded Generation Facilities pursuant to this Agreement for a Customer Event of Default or any other reason attributable to the action or inaction of the Customer, or any cause related to, or connected with, the Customer, or the Customer requests THESL to disconnect the Facility, and the Customer requests that the Embedded Generation Facilities be reconnected, the Customer shall pay the costs of such reconnection as set out in the Conditions of Service or where not specified in the Conditions of Service as determined by THESL in its sole discretion, acting reasonably, and in either case including any amounts which may be due and owing to THESL under this

Agreement. Such costs shall be paid in full prior to the reconnection of the Embedded Generation Facilities.

Prior to the initial connection, or upon request of THESL after any disconnection, the Customer shall comply with the following conditions prior to such connection or reconnection:

1. Testing

(a) THESL shall provide prior written notice to the Customer of the Tests which it reasonably determines must be performed prior to reconnection;

(b) the Customer shall obtain prior written approval from THESL for the contractor who will perform the Tests; provided that if a contractor is on the most recent list of approved contractors published by THESL from time to time no written approval shall be required; and

(c) after completion of the Tests, the Customer shall deliver the results of the Tests to THESL.

The Embedded Generation Facilities shall not be connected or reconnected until THESL is satisfied the results of the Tests show the security, safety, efficiency, and reliability of the THESL Distribution System will not be adversely affected by the connection or reconnection.

2. ESA Approval

The Customer shall, at its expense, have the Embedded Generation Facilities inspected and approved by the ESA and obtain a written certificate from the ESA certifying that the ESA has inspected the electrical installations of the Embedded Generation Facilities to allow for the performance of the Tests, and in-service operation of the Embedded Generation Facilities and deliver, or have delivered, to THESL such written certificate from the ESA. THESL will not allow the Embedded Generation Facilities to be connected to the THESL Distribution System for the purpose of performing the Tests hereunder until THESL receives a written connection authorization from the ESA for the Embedded Generation Facilities and all other requirements of THESL for the connection of the Embedded Generation Facilities to the THESL Distribution System are met.

6.3 Upon receipt of a disconnection request from the Customer, THESL will disconnect and/or remove THESL's Apparatus at the Customer's cost as outlined in the Conditions of Service.

ARTICLE 7: INSURANCE

7.1 The Customer shall, at its own expense, acquire and maintain during the Term any and all insurance required by the laws in effect in Ontario for the testing, operation and maintenance of the Embedded Generation Facilities, including the following insurance coverage:

(a) comprehensive general liability insurance with limits of not less than ten million dollars ($10,000,000.00) inclusive per occurrence for bodily injury, death and damage to property, including loss of use and, such insurance should include, but not be limited to, blanket contractual and cross liability coverage; and

(b) all risk property insurance with limits of not less than five million dollars ($5,000,000.00) inclusive per occurrence.

7.2 Upon request, the Customer shall provide THESL with written proof of insurance coverage consistent with the above provisions. Where applicable, each policy shall list THESL and its Representatives as Additional Insureds.

7.3 The Customer shall ensure that any contractor it retains to perform any of the Tests hereunder obtains and maintains, the same types and levels of insurance as set forth in Section 7.1 and that THESL and its Representatives are named as additional insureds under such insurance policies, where applicable.

7.4 THESL, acting reasonably, may from time to time request that the Customer take out additional insurance coverage and the Customer shall acquire such additional policies and provide written proof of such additional coverage within thirty (30) days of such request. All policies of insurance provided for under this section shall provide that THESL shall receive at least thirty (30) days prior written notice of cancellation, termination or of any material change to the Customer's insurance. The Customer shall not terminate, allow to lapse or change the terms of the Customer's insurance as required herein without THESL's prior written approval.

7.5 If the Customer fails to provide proof of, and maintain the insurance required herein, THESL will be entitled to obtain and maintain such insurance and give written notice of that fact to the Customer. The cost of obtaining and maintaining the insurance will be at the expense of the Customer and the Customer will reimburse THESL for any amount paid by THESL related thereto within ten (10) days of receipt of an invoice therefore.

ARTICLE 8: COMPLIANCE WITH LAWS

8.1 The Customer and its Representatives shall comply with all applicable federal, provincial and municipal laws, regulations, by-laws, codes, and orders with respect to the Customer's obligations under this Agreement, including, without limitation, the *Occupational Health and Safety Act* (Ontario), the *Electrical Safety Code* (Ontario), and the *Workplace Safety and Insurance Act* (Ontario).

ARTICLE 9: LIABILITY

9.1 The Customer shall have the risk and all liability in respect of:

(a) all loss, damage or injury to property owned by THESL, or to property for which THESL has jurisdiction under this Agreement, or is at law responsible for, located on the lands and premises owned by the Customer, unless due to a negligent act or omission of THESL or any of its Representatives; and

(b) all loss, damage or injury to:

(i) property of the Customer, or property of a third person, on the lands and premises owned by the Customer; and

(ii) any person or persons (including loss of life), whether on the lands or premises owned by the Customer, or owned or used by THESL, or otherwise, resulting from any of the Tests or operation of the Embedded Generation Facilities, whether in accordance with this Agreement or otherwise,

except to the extent that such loss, damage or injury is the result of the negligent action or omission of THESL or any of its Representatives.

9.2 Notwithstanding any other provision in this Agreement, or any applicable statutory provision:

(a) neither THESL nor any of its Representatives shall be liable to the Customer for any losses, damages, claims, liabilities, costs or expenses arising from any breach of this Agreement or any tortious act, other than for losses, damages, claims, liabilities, costs or expenses directly resulting from the negligence or wilful misconduct of THESL and which result in physical damage to the property of the Customer; and

(b) neither THESL nor any of its Representatives shall be liable to the Customer under any circumstances for any indirect, incidental, or special or consequential damages, whether punitive or exemplary, including damages for loss of use or profits or revenues, business

interruption losses, loss of contract or loss of goodwill, or other economic benefits, arising directly or indirectly from any breach of this Agreement, fundamental or otherwise, or from any tortious acts, including negligence or gross negligence or wilful misconduct or omissions, of THESL or any of its Representatives.

ARTICLE 10: INDEMNIFICATION

10.1 Except to the extent such obligations are modified by applicable law, the Customer shall indemnify and save harmless THESL and all of its Representatives against all claims, losses, expenses, damages, costs, actions or proceedings incurred by, or instituted against, them which relate to, arise out of, or are attributable in any way to the Tests, Commissioning, connecting or operating the Embedded Generation Facilities regardless of whether such Tests, Commissioning, connecting or operating were in accordance with this Agreement and whether the Customer has been negligent in the performance of the Tests or its operation of the Embedded Generation Facilities, or which relate to, arise out of, or are attributed to a breach of, or default under this, Agreement, or the negligence or willful misconduct of the Customer or any of its Representatives.

10.2 "Force Majeure" means in relation to either party ("Non-Performing Party"), any event or circumstance which (i) is beyond the reasonable control of such party including, without limitation, severe weather, strikes, riots, civil disturbances, sabotage or acts of public enemy, war, insurrection, earthquake, explosion, or order, regulation or restriction imposed by any authorities having authority to issue such order, regulation or restriction, (ii) could not have been avoided through the use of Good Utility Practice (provided that a party shall have the right to determine and settle in its sole discretion any labor dispute in which that party may be involved), (iii) does not result from the negligence or fault of that party or any of its Representatives and (iv) results in or causes the inability of the party to perform any of its obligations under the Agreement (other than for payment of monies due hereunder) or whereby electricity cannot flow from the THESL Distribution System to the Embedded Generation Facilities or which causes the THESL Distribution System to be incapable of being operated lawfully, safely or at all; provided however that lack of funds shall not be interpreted as a cause beyond the reasonable control of either party.

10.3 If because of the occurrence of an event of Force Majeure either the Customer or THESL is unable to carry out any of its obligations under this Agreement, the obligations of the Non-Performing Party and the corresponding obligations of the other party shall be suspended to the extent necessary by and during the continuance of such Force Majeure; provided however, that Non-Performing Party shall only be entitled to claim Force Majeure if the following conditions have been met:

(a) the Non-Performing Party has promptly given the other party written notice of the event of Force Majeure together with an estimate in good faith of the effect that the event will have on its ability to perform each of its obligations;

(b) the Non-Performing Party shall only be entitled to suspend performance of its obligations as a consequence of the event of Force Majeure to the extent and for such period of time as the event of Force Majeure requires it to do so;

(c) the Non-Performing Party has used its best efforts to mitigate the effects of the event of Force Majeure, remedy its inability to perform and resume full performance of its obligations hereunder;

(d) the Non-Performing Party has continually informed the other party of its efforts taken in compliance with Section 10.3(c) above; and

(e) the Non-Performing Party has provided written notice to the other party upon resuming performance of any obligation affected by the event of Force Majeure.

10.4 The Customer may not materially increase the generated supply at the Point of Connection without the prior written approval of THESL, which approval may not be unreasonably withheld. The Customer shall provide THESL with all information requested by it to reasonably consider the application for approval. If any material increase in generated supply is made in contravention of this Section 10.4, it shall be an Event of Default, THESL shall have the right to terminate this Agreement pursuant to Section 5.3 and the provisions of Section 5.4 shall apply to such termination. In addition to any other indemnity contained herein, the Customer shall be liable to THESL for, and shall indemnify THESL against, any damages to the THESL Distribution System resulting from any unapproved increase in the generated supply.

ARTICLE 11: RELATIONSHIPS OF PARTIES

11.1 Nothing in this Agreement shall be deemed to constitute either party hereto as partner, agent or representative of the other party or to create any fiduciary relationship between the parties.

ARTICLE 12 MISCELLANEOUS PROVISIONS

12.1 From time to time certain improvements, additions or other changes ("Modification") to the Embedded Generation Facilities may be required for their economical, reliable and safe operation. The Customer may not make any Modification without prior written consent of THESL, which consent may not be unreasonably withheld. The Customer shall provide THESL with all information requested by it to reasonably consider the application for consent. Any consent given by THESL shall be deemed to

contain the conditions that the Modification shall be made (i) in accordance with the standards and procedures of THESL in effect at the time the Modification is made and (ii) at the Customer's expense. In the event that the Customer disagrees with THESL's refusal to give any such consent, it may elect to terminate this Agreement upon thirty (30) days prior written notice. If any Modification is made in contravention of this Section 12.1, THESL shall have the right to terminate this Agreement pursuant to Section 5.3 and the provisions of Section 5.4 shall apply to such termination.

12.2 Any waiver of any right under this Agreement shall be in writing and any failure by either party to exercise any right or to enforce any remedy under this Agreement shall not be deemed to be a waiver of any other right or remedy or affect the validity of this Agreement.

12.3 In the event of any dispute arising out of this Agreement, THESL and the Customer agree as follows:

(a) to attempt, in good faith, to negotiate a settlement of the dispute between themselves within 45 days from the date the dispute arose;

(b) in the event that the parties cannot settle the dispute between themselves, either party may, following the passage of at least 45 days from the date the dispute arose (as evidenced by writing between the parties) either party may submit the dispute for arbitration by a single arbitrator in accordance with the *Arbitration Act, 1991 (Ontario)*;

(c) the submission of a dispute shall not act as a stay of performance of obligations under this Agreement; and

(d) the decision of the arbitrator will be final and binding with no right of appeal.

Nothing contained in this Section 12.3 shall be interpreted as limiting any jurisdiction granted to the Ontario Energy Board by any applicable law.

12.4 THESL shall invoice the Customer and the Customer shall pay to THESL, within 10 days of receipt of an invoice, all additional or special costs relating to the interconnection with, or the operation of, the THESL Distribution System while interconnected with, the Embedded Generation Facilities. For the purpose of this Section 12.4 "additional or special costs" shall mean those costs incurred by THESL which THESL, in its sole discretion, determines arise out of the special nature and characteristics of the Embedded Generation Facilities and are costs not normally incurred by THESL in the ordinary course of interconnection with, or operation while interconnected to, facilities operating in parallel.

12.5 The Customer agrees that THESL shall have the right to revise any provision in this Agreement, including any Operating Schedule, or insert any provision into this Agreement, that it determines, in its sole discretion, is required, for any reason, (a) to protect the security, efficiency, reliability and safety of the THESL Distribution System or safety of THESL personnel or any other property or persons; or (b) to make the provisions of this Agreement comply with all applicable laws or the Conditions of Service; provided that, THESL shall provide no less than 30 days prior notice of such change to the Customer and the Customer shall have the right to terminate the Agreement within 10 days of receipt of such notice. The provisions of Section 5.4 shall apply to any such termination.

12.6 Telephone communication between the Customer and THESL is required at all times when the Tests are being performed and such communications shall be made to the telephone and fax numbers provided from time to time by party.

ARTICLE 13: DEFINITIONS

13.1 In this Agreement, the definitions contained in Appendix 1 of Schedule A attached hereto shall have the meanings set forth therein and, in addition, the following terms shall have the meanings set forth below:

(a) “Agreement” means the agreement of THESL to connect the Embedded Generation Facilities to the THESL Distribution System upon these terms and conditions and the Customer’s deemed agreement pursuant to the Distribution System Code and the Conditions of Service to be bound by these terms and conditions.

(b) "Apparatus" means structures, equipment and apparatus pertaining to the generation, transmission, distribution or use of power.

(c) "Business Day" shall mean any day on which the Royal Bank of Canada is open for business in Toronto, Ontario;

(d) "Competent Person" means one qualified by knowledge, training and experience to perform assigned work.

(e) "Conditions of Service" means the document developed by THESL in accordance with subsection 2.4 of the Distribution System Code that describes the operating practices and connection rules for THESL as amended from time to time.

(f) "Connection Date" means the date of this Agreement.

(g) "Distribution License" means any license to distribute electricity issued to THESL by the Ontario Energy Board.

(h) "Distribution System Code" means the code, approved by the Ontario Energy Board, and in effect at the relevant time, which, among other things, establishes the obligations of THESL and other distribution systems with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards for THESL and other distribution systems.

(i) “Embedded Generation Facilities” means the generation facilities of a generator which are not directly connected to the IMO-controlled grid but are instead connected, or to be connected, to the THESL Distribution System.

(j) “Emergency” means a condition or situation which in the judgement of THESL will affect THESL’s ability to meet its obligations to (i) maintain safe, adequate and continuous electric service or (ii) avoid damage to any property or persons.

(k) "Energized" means the joining of the Embedded Generation Facilities to the THESL Distribution System by means of Approved Work Practices either initially or following a disconnection for whatever reason so that Customer may make or receive a supply of electricity to or from THESL Distribution System at the Point of Connection.

(l) “ESA” means the person or body designated under the *Electricity Act, 1998*, S.O. 1998, c.15, Schedule A as the Electrical Safety Authority.

(m) “Good Utility Practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in North America.

(n) "Operating Schedule" means any operating schedule delivered from time to time by THESL which specifies, among other things, standards and procedures for operating and maintaining the Embedded Generation Facilities.

(o) "Point of Connection" has the meaning set forth in Section 2.1 hereto.

(p) "Representatives" means the respective directors, officers, employees, contractors or agents of either party hereto, as applicable.

(q) “Site” means the physical location of the Embedded Generation Facilities.

(r) “Term” has the meaning set out in Section 5.1 hereto.

(s) “Tests” means the tests performed on the Embedded Generation Facilities to ensure that the Embedded Generation Facilities are properly designed for connection, and are acceptable to be connected, to the THESL Distribution System.

(t) “THESL Distribution System” means the system used by THESL for distributing electricity and includes any structures, equipment or other things used for that purpose.

Section 6 – REFERENCES

Schedule C

Wholesale Market Participant Connection Agreement Terms and Conditions

See next 14 pages for terms and conditions

WHOLESALE MARKET PARTICIPANT CONNECTION AGREEMENT

TERMS AND CONDITIONS

ARTICLE 1: CONNECTION

1.1 The Facility shall be connected to the THESL Distribution System and remain Energized at the Points of Connection from the Connection Date for the duration of the Term on the terms and subject to the conditions set out in this Agreement.

ARTICLE 2: POINTS OF CONNECTION AND JURISDICTION

2.1 The points of delivery and connection for the Facility shall be where the THESL supply feeders connect to the high-voltage disconnect switches (the "Points of Connection") or such other points as may be designated by THESL.

2.2 THESL shall have jurisdiction and control over the area between the point of entry of THESL supply feeders onto the Customer's property at the Site and the load side of the Customer-owned switchgear, including;

(i) the electrical interlocks for the close operations of the circuit breakers to ensure the non-paralleling of the supply feeders; and
(ii) THESL's revenue billing metering equipment;

or such areas as may be designated by THESL.

ARTICLE 3: COVENANTS OF THE CUSTOMER

3.1 The Facility, when inter-connected to the THESL system, shall not adversely affect or damage:

a. the health and safety of THESL or any of its Representatives or the general public;
b. the Apparatus owned or operated by THESL;
c. the THESL Distribution System;
d. the security, safety, or reliability of the THESL Distribution System;
e. in a material manner, the efficiency of the THESL Distribution System; or
f. in a material manner, the quality of the electrical power supply provided by THESL to the Customer or other THESL customers.

3.2 The Customer shall, at its expense, maintain any and all permits, licenses and approvals required by law for the operation and maintenance of the Facility ("Required Approvals") throughout the Term.

3.3 The Customer shall (i) pay THESL for all electricity distribution services provided by THESL to the Site during the Term at such rates as may be approved by the Ontario Energy Board ("OEB") from time to time for the appropriate class rating to which the services apply; (ii) make such payments in accordance with THESL's billing cycle as notified to the Customer from time to time; and (iii) pay late payment and other charges and pay such deposits as may be required by THESL from time to time as part of the OEB-approved rate structure. The Customer shall also pay to THESL such other charges as THESL may be required by applicable law to bill and/or collect for third parties including electricity retailers, the Independent Market Operator, Ontario Energy Board and any transmission company.

3.4 The Customer shall not, in installing, operating or maintaining the Facility:

a. violate, or cause THESL to violate, any provision of its Distribution License;

b. contravene any laws of the Province of Ontario or any laws of Canada having force and effect in the Province of Ontario; or

c. violate any provision contained in the Conditions of Service.

3.5 The Customer shall comply as soon as possible with any reasonable directive received from THESL that THESL makes for the purpose of meeting any of its obligations under its Distribution License.

3.6 In addition to the obligations set forth in this Agreement, the Customer shall be bound by, and shall comply with, all provisions of THESL's Conditions of Service.

3.7 The Customer shall maintain all parts of the Facility, including, connection Devices, protection and control systems in good working order in accordance with the Distribution System Code and the Conditions of Service and otherwise in a manner consistent with Good Utility Practice.

3.8 The Customer shall limit the effects of harmonic voltages and currents on the THESL Distribution System caused by the Facility in accordance with the IEEE specification 519-1992 titled "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems". In the event THESL, in its discretion, deems it necessary for modifications to be made to the Facility to achieve acceptable power quality, the Customer shall make such modifications, at its own cost, within such time period as is specified by THESL ("Modification Period"), acting reasonably; provided that if the modifications are not completed within 14 days of receipt of a notice of non-performance delivered after the expiry of the Modification Period, THESL shall be entitled to disconnect the Facility from the THESL Distribution System without any further notice.

3.9 THESL shall be entitled to access to the property of the Customer at all reasonable times, to inspect, maintain, repair, alter, remove, replace or disconnect wires or other parts of the Facility, or to install, inspect, read, calibrate, maintain, repair, alter, remove or replace a meter, which are located on the property and to take any actions necessary to maintain the safe and reliable operation of the THESL Distribution System. The Customer shall also provide THESL with such other access as may be specified in the Conditions of Service, Operating Schedule or by law. In accessing the property of the Customer, THESL shall comply with the Customer's reasonable security practices and procedures to the extent it is made aware of such practices and procedures.

The Customer agrees to provide suitable space for THESL's existing meters, wires, poles, cables, transformers and other appliances and equipment (collectively "Metering Equipment") at the Site and for any Metering Equipment which THESL may be required by law to install at any time after the date of this Agreement and further agrees that, without to prior written consent of THESL (not to be unreasonably withheld) it shall not permit any one who is not an agent of THESL to remove, inspect or tamper with same, including moving, inspecting or tampering with the seals. The Customer agrees that Representatives of THESL shall have reasonable access to the Site and Facility for the purposes of reading, examining, preparing or removing its meters, wires, poles, cables, transformers and other appliances, materials and equipment and for the purpose of inspecting the Customer's appliances, equipment and wiring.

3.10 The Customer shall have no rights of access to THESL Apparatus or lands or property owned by THESL.

3.11 If, as a consequence of the connection of the Facility to the THESL Distribution System or the Tests performed hereunder, damage occurs to the Apparatus owned or operated by THESL ("THESL Apparatus") or the THESL Distribution System, the Customer shall, within 10 days of receipt of an invoice therefore, pay the amount of any such damage to THESL.

3.12 If so required by Hydro One, THESL or any regulatory authority as determined in accordance with applicable laws, at any future date, the Customer shall, as its expense, install performance metering equipment.

3.13 If the Customer installs performance metering equipment in accordance with Section 3.12, the Customer shall allow THESL to receive output from the performance metering equipment, and the Customer shall install and maintain any equipment necessary to allow THESL to do so, at no cost to THESL.

ARTICLE 4: TERM AND TERMINATION

4.1 Unless terminated earlier in accordance with the terms of this Agreement, this Agreement shall be effective as of the date first written above and shall continue in full force and effect until either party gives no less than 365 days written notice to the other party of its intention to terminate this Agreement (the "Term"). Any such notice of termination shall specify the effective date of termination; provided that notwithstanding the delivery of a notice of termination under this Section 4.1, THESL shall have the right to terminate this Agreement prior to the specified effective date of termination pursuant to Section 4.2.

4.2 The occurrence of any of the following shall constitute an event of default ("Event of Default") on the part of the defaulting party:

a. failure to pay any sum, due and owing hereunder including any sum owing pursuant to Section 3.3, within 5 days of receipt of a notice of failure to pay from the non-defaulting party;

b. failure to comply with any other material covenant or obligation set forth in this Agreement within 14 days of receipt of notice of default from the non-defaulting party; or

c. the occurrence of a material breach or default under any other agreement between the parties.

4.3 a Upon the occurrence of an Event of Default, where the Customer is the defaulting party ("Customer Event of Default") THESL shall have the right to:

(i) give notice of termination to the Customer whereupon the Agreement shall terminate as at the effective date of termination specified in the notice; and

(ii) disconnect the Facility from the THESL Distribution System in accordance with Section 5.1 below.

b Upon the occurrence of an Event of Default where THESL is the defaulting party ("THESL Event of Default"), the Customer shall have the right to give notice of termination to THESL whereupon the Agreement shall terminate as at the effective date of termination specified in the notice.

4.4 Upon termination of the Agreement by THESL in accordance with its provisions, without prejudice to any other rights THESL may have:

a. all amounts outstanding pursuant to this Agreement shall immediately become due and payable by the Customer;

b. THESL shall be entitled to enter onto the Customer's property to remove, at the Customer's expense, any THESL Apparatus as soon as reasonably practicable;

c. the relevant provisions of this Agreement shall continue in effect after expiry or termination to the extent necessary to provide for any billings, adjustments and payments related to the period prior to the termination and for the payment of any monies due and owing pursuant to this Agreement;

d. the termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either party under this Agreement, which are intended to continue after termination of such Agreement, including, without limitation, Article 7; Article 8; and Sections 4.4, 4.5 and 10.3;

e. THESL shall have no liability whatsoever to the Customer arising from such termination; and

f. THESL may, if it has not already done so pursuant to Section 4.3 hereof, disconnect the Facility from the THESL Distribution System.

4.5 Upon termination of the Agreement by Customer in accordance with its provisions, without prejudice to any other rights Customer may have:

a. all amounts outstanding pursuant to this Agreement shall immediately become due and payable by THESL;

b. the relevant provisions of this Agreement shall continue in effect after expiry or termination to the extent necessary to provide for any billings, adjustments and payments related to the period prior to the termination and for the payment of any monies due and owing pursuant to this Agreement;

c. the termination of this Agreement shall not affect any rights or obligations which may have accrued prior to such termination or any other rights which the terminating party may have arising out of either the termination or the event giving rise to the termination and shall not affect any continuing obligations of either party under this Agreement, which are intended to continue after termination of such Agreement, including, without limitation, Article 7; Article 8 and Sections 4.4, 4.5 and 10.3;

d. Customer shall have no liability whatsoever to the THESL arising from such termination; and

e. THESL shall, if it has not already done so, disconnect the Facility from the THESL Distribution System.

ARTICLE 5: DISCONNECTION

5.1 Notwithstanding anything else contained in this Agreement, THESL may disconnect the Facility from the THESL Distribution System:

a. if an Event of Default occurs, upon reasonable prior notice to the Customer; provided that:

(i) THESL may, if it, in its sole discretion, acting reasonably, deems it necessary for any reason whatsoever, disconnect the Facility from the THESL Distribution System immediately without any notice to the Customer; and

(ii) if the disconnection is as a result of non-payment of monies due and owing hereunder, THESL shall provide no less than 7 days notice of such disconnection.

b. immediately without notice, if THESL, in its sole discretion, determines it is necessary:

(i) to protect the health or safety of THESL personnel, its contractors or any third parties;

(ii) to prevent damage to the THESL Distribution System or any other property;

(iii) to preserve the security, safety, or reliability of the THESL Distribution System or services delivered thereunder;

(iv) to prevent a material adverse effect on the efficiency of the THESL Distribution System or quality of electrical power supply provided by THESL to the Customer or other THESL customers;

(v) as a result of any other circumstances which THESL in its sole discretion, determines to be an Emergency; or

(vi) the Customer has failed to comply with the Ontario Electrical Safety Code;

c. upon reasonable prior notice to the Customer to perform any unplanned inspection or maintenance;

d. upon termination this Agreement pursuant to Section 4.1 or 4.3;

e. immediately without notice, upon issuance of an order or directive requiring disconnection by any court or regulatory authority having jurisdiction to issue such an order or directive; or

f. for any other reason specified in this Agreement or in the Conditions of Service.

5.2 a. If THESL exercises any rights to disconnect the Facility pursuant to this Agreement for an Customer Event of Default or any other reason attributable to the action or inaction of the Customer, or any cause related to or connected with the Customer, or the Customer requests THESL to disconnect the Facility, and the Customer requests that the Facility be reconnected, for any reason, the Customer shall pay the reasonable costs of such reconnection as set out in the Conditions of Service or where not specified in the Conditions of Service as determined by THESL in its sole discretion, acting reasonably and in either case, including any monies which may be due and owing to THESL under this Agreement including pursuant the Section 3.3. Such costs shall be paid in full prior to the reconnection of the Facility.

b. Upon request of THESL, the Customer shall comply with the following conditions prior to reconnection:

1. Testing

(i) THESL shall provide prior written notice to the Customer of the Tests which it reasonably determines must be performed prior to reconnection;

(ii) the Customer shall obtain prior written approval from THESL for the contractor who will perform the Tests; provided that if a contractor is on the most recent list of approved contractors published by THESL from time to time no written approval shall be required; and

(iii) after completion of the Tests, the Customer shall deliver the results of the Tests to THESL.

The Facility shall not be reconnected until THESL is satisfied the results of the Tests show the security, safety, efficiency, and reliability of the THESL Distribution System will not be adversely affected by the reconnection.

2. ESA Approval

The Customer shall, at its expense, have the Facility inspected and approved by the ESA and obtain a written certificate from the ESA certifying that the ESA has inspected the electrical installations of the Facility to allow for the performance of the Tests, and in-service operation of the Facility and deliver, or have delivered, to THESL such written certificate from the ESA. THESL will not allow the Facility to be connected to the THESL Distribution System for the purpose of performing the Tests hereunder until THESL receives a written connection authorization from the ESA for the Facility and all other requirements of THESL for the connection of the Facility, if requested by THESL, to the THESL Distribution System are met.

5.3 Upon receipt of a disconnection request from the Customer, THESL will disconnect and/or remove THESL's Apparatus at the Customer's reasonable cost as outlined in the Conditions of Service.

ARTICLE 6: COMPLIANCE WITH LAWS

6.1 The Customer and its Representatives shall comply with all applicable federal, provincial and municipal laws, regulations, by-laws, codes, and orders with respect to the Customer's obligations under this Agreement, including, without limitation, the *Occupational Health and Safety Act* (Ontario), the *Electrical Safety Code* (Ontario), and the *Workplace Safety and Insurance Act* (Ontario).

ARTICLE 7: LIABILITY

7.1 The Customer shall have the risk and all liability in respect of:

a. all loss, damage or injury to property owned by THESL, or to property for which THESL has jurisdiction under this Agreement, or is at law responsible for, located on the lands and premises owned by the Customer, unless due to a negligent act or omission of THESL or any of its Representatives; and

b. all loss, damage or injury to:

(i) property of the Customer, or property of a third person, on the lands and premises owned by the Customer; and

(ii) any person or persons (including loss of life), whether on the lands or premises owned by the Customer, or owned or used by THESL, or otherwise, resulting from any of the Tests or operation of the Facility, whether in accordance with this Agreement or otherwise,

except to the extent that such loss, damage or injury is the result of the negligent action or omission of THESL or any of its Representatives.

7.2 Notwithstanding any other provision in this Agreement, or any applicable statutory provision:

a. neither THESL nor any of its Representatives shall be liable to the other party for any losses, damages, claims, liabilities, costs or expenses arising from any breach of this Agreement or any tortious act, other than for losses, damages, claims, liabilities, costs or expenses directly resulting from the negligence or wilful misconduct of THESL or any of its Representatives; and;

b. neither THESL nor any of its Representatives shall be liable to the other party under any circumstances for any indirect, incidental, or special or consequential damages, whether punitive or exemplary, including damages for loss of use or profits or revenues, business interruption losses, loss of contract or loss of goodwill, or other economic benefits, arising directly or indirectly from any breach of this Agreement, fundamental or otherwise, or from any tortious acts, including negligence or gross negligence or wilful misconduct or omissions, of THESL or any of its Representatives.

ARTICLE 8: INDEMNIFICATION

8.1 Except to the extent such obligations are modified by applicable law, the Customer shall indemnify and save harmless THESL and all of its Representatives against all claims, losses, expenses, damages, costs, actions or proceedings incurred by, or instituted against, them which relate to, arise out of, or are attributable in any way to the connecting or operating the Facility regardless of whether such connecting or operating were in accordance with this Agreement and whether the Customer has been negligent in the performance of its operation of the Facility, or which relate to, arise out of, or are attributable to a breach of, or default under this, Agreement by, or the negligence or willful misconduct of, the Customer or any of its Representatives.

8.2 "Force Majeure" means in relation to either party ("Non-Performing Party"), any event or circumstance which (i) is beyond the reasonable control of such party, including without limitation severe weather, strikes, riots, civil disturbances, sabotage or acts of a public enemy, war, insurrection, earthquake, explosion, or order, regulation, or restriction imposed by any authorities, having authority to issue such orders, regulations or restrictions (ii) could not have been avoided through the use of Good Utility Practice (provided that a party shall have the right to determine and settle in its sole discretion any labor dispute in which that party may be involved), (iii) does not result from the negligence or fault of that party or any of its Representatives and (iv) results in or causes the inability of the party to perform any of its obligations under the Agreement (other than for payment of monies due hereunder) or whereby electricity cannot flow from the THESL

Distribution System to the Facility or which causes the THESL Distribution System to be incapable of being operated lawfully, safely or at all; provided however that lack of funds shall not be interpreted as a cause beyond the reasonable control of either party.

8.3 If because of the occurrence of an event of Force Majeure either the Customer or THESL is unable to carry out any of its obligations under this Agreement, the obligations of the Non-Performing Party and the corresponding obligations of the other party shall be suspended to the extent necessary by and during the continuance of such Force Majeure; provided however, that Non-Performing Party shall only be entitled to claim Force Majeure if the following conditions have been met:

a. the Non-Performing Party has promptly given the other party written notice of the event of Force Majeure together with an estimate in good faith of the effect that the event will have on its ability to perform each of its obligations;

b. the Non-Performing Party shall only be entitled to suspend performance of its obligations as a consequence of the event of Force Majeure to the extent and for such period of time as the event of Force Majeure requires it to do so;

c. the Non-Performing Party has used its best efforts to mitigate the effects of the event of Force Majeure, remedy its inability to perform and resume full performance of its obligations hereunder;

d. the Non-Performing Party has continually informed the other party of its efforts taken in compliance with Section 8.3(c) above; and

e. the Non-Performing Party has provided written notice to the other party upon resuming performance of any obligation affected by the event of Force Majeure.

8.4 The Customer may not materially increase the load at the Points of Connection without the prior written approval of THESL, which approval may not be unreasonably withheld. The Customer shall provide THESL with all information requested by it to reasonably consider the application for approval. If any material increase in load is made in contravention of this Section 8.4, it shall be an Event of Default, THESL shall have the right to terminate this Agreement pursuant to Section 4.3 and the provisions of Section 4.4 shall apply to such termination. In addition to any other indemnity contained herein, the Customer shall be liable to THESL for, and shall indemnify THESL against, any damages to the THESL Distribution System resulting from of any unapproved increase in the load.

ARTICLE 9: RELATIONSHIPS OF PARTIES

9.1 Nothing in this Agreement shall be deemed to constitute either party hereto as partner, agent or representative of the other party or to create any fiduciary relationship between the parties.

ARTICLE 10 MISCELLANEOUS PROVISIONS

10.1 From time to time certain improvements, additions or other changes ("Modification") to the Facility may be required for their economical, reliable and safe operation. The Customer may not make any material Modification without prior written consent of THESL, which consent may not be unreasonably withheld. The Customer shall provide THESL with all information requested by it to reasonably consider the application for consent. Any consent given by THESL shall be deemed to contain the conditions that the Modification shall be made (i) in accordance with the Conditions of Service of THESL in effect at the time the Modification is made and (ii) at the Customer's expense. In the event that the Customer disagrees with THESL refusal to give any such consent, it may elect to terminate this Agreement upon thirty (30) days prior written notice. If any material Modification is made in contravention of this Section 10.1, THESL shall have the right to terminate this Agreement pursuant to Section4.3 and the provisions of Section 4.4 shall apply to such termination.

10.2 Any waiver of any right under this Agreement shall be in writing and any failure by either party to exercise any right or to enforce any remedy under this Agreement shall not be deemed to be a waiver of any other right or remedy or affect the validity of this Agreement.

10.3 In the event of any dispute arising out of this Agreement, THESL and the Customer agree as follows:

a. to attempt, in good faith, to negotiate a settlement of the dispute between themselves within 45 days from the date the dispute arose;

b. in the event that the parties cannot settle the dispute between themselves, either party may, following the passage of at least 45 days from the date the dispute arose (as evidenced by writing between the parties) either party may submit the dispute for arbitration by a single arbitrator in accordance with the *Arbitration Act, 1991 (Ontario)*; provided that, in the event the dispute relates solely to the payment of money under this Agreement, the submitting of the dispute for arbitration shall operate as a stay in respect of the payment of monies to the extent of the amount in dispute until such time as the decision of the arbitrator is rendered; and

c. the decision of the arbitrator will be final and binding with no right of appeal.

10.4 Any amount to be paid under this Agreement unless otherwise specified, shall become due and owing and be paid by the Customer to THESL 10 days after receipt of an invoice for such amount from THESL.

10.5 Any amount required to be paid under this Agreement, which is not paid on the due date therefore, shall bear interest at the rate of 1.5 percent calculated and compounded monthly (19.56 percent per annum) at and from the due date up to and including the date of payment in full of such amount, together with all interest accrued to the date of payment.

10.6 The Customer agrees that THESL shall have the right to revise any provision in this Agreement, or insert any provision into this Agreement, that it determines, in its sole discretion, is required, for any reason, (a) to protect the security, efficiency, reliability and safety of the THESL Distribution System or safety of THESL personnel or any other property or persons; provided however that such change shall not result in a disconnection upon less than 48 hours notice or resulting in Customer being required to pay unreasonable costs; or (b) to make the provisions of this Agreement consistent with a change in applicable laws or in the Conditions of Service; provided that, THESL shall provide no less than 30 days prior notice of such change to the Customer and the Customer shall have the right to terminate the Agreement within 10 days of receipt of such notice. The provisions of Section 4.4 shall apply to any such termination.

10.7 Telephone communication between the Customer and THESL is required at all times when the Tests are being performed and such communications shall be made to the telephone and fax numbers provided from time to time by each party.

ARTICLE 11: DEFINITIONS

11.1 In this Agreement, the following terms shall have the meanings set forth below:

a. “Agreement” means the agreement of THESL to connect the Facilities to the THESL Distribution System upon these terms and conditions and the Customer’s deemed agreement pursuant to the Conditions of Service to be bound by these terms and conditions, as amended from time to time.

b. "Apparatus" means structures, equipment or apparatus pertaining to the generation, transmission, distribution or use of power.

c. "Business Day" shall mean any day on which The Royal Bank of Canada is open for business in Toronto, Ontario;

d. "Competent Person" means one qualified by knowledge, training and experience to perform assigned work.

e. "Conditions of Service" means the document developed by THESL in accordance with subsection 2.4 of the Distribution System Code that describes the operating practices and connection rules for THESL as amended from time to time.

f. "Connection Date" means the date of connection of the Facility to the THESL Distribution System.

g. "Distribution License" means any license to distribute electricity issued to THESL by the Ontario Energy Board.

h. "Distribution System Code" means the code, approved by the Ontario Energy Board, and in effect at the relevant time, which, among other things, establishes the obligations of THESL and other distribution systems with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards for THESL and other distribution systems.

i. "Emergency" means a condition or situation which in the judgement of THESL as will affect THESL's ability to meet its obligations to maintain safe, adequate and continuous electric service or to avoid damage to any property or persons.

j. "Energized" means the joining of the Facility to the THESL Distribution System by means of Approved Work Practices either initially or following a disconnection for whatever reason so that Customer may make or receive a supply of electricity to or from THESL Distribution System at the Points of Connection.

k. "ESA" means the person or body designated under the *Electricity Act, 1998*, S.O. 1998, c.15, Schedule A as the Electrical Safety Authority.

l. "Facility" means the system identified in the Toronto Hydro single-line diagram for a property connection to the THESL Distribution System.

m. "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in North America.

n. "Points of Connection" shall have the meaning set out in Section 2.1 hereto.

o. "Representatives" means the respective directors, officers, employees, contractors or agents of either party hereto, as applicable.

p. “Site” means the physical location of the Facility.

q. “Term” has the meaning set out in Section 4.1 hereto.

r. “Tests” means the tests performed on the Facility to ensure that the Facility is designed and acceptable to be connected to the THESL Distribution System.

s. “THESL Distribution System” means the system used by THESL for distributing electricity and includes any structures, equipment or other things used for that purpose.

toronto hydro
electric system

TORONTO HYDRO-ELECTRIC SYSTEM LTD.

PARALLEL GENERATION REQUIREMENTS

REVISION #2: JANUARY 23, 2007

Prepared by: _____
Peter Baroutis, P. Eng.
ENGINEER, POLICY & STANDARDS

Reviewed by: _____
Romano Sironi, P. Eng.
MANAGER, POLICY & STANDARDS

CERTIFICATE OF APPROVAL THIS TECHNICAL SPECIFICATION MEETS THE SAFETY REQUIREMENTS OF SECTION 4 OF ONTARIO REGULATION 22/04	
_____	Jan. 23, 2007
Romano Sironi, P. Eng.	**Date**

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Introduction

The technical requirements for parallel generation are in place to ensure public and employee safety, protect the integrity of Toronto Hydro's system, and guarantee reliable and quality service to Toronto Hydro customers. The technical requirements in this document are for the protection of Toronto Hydro's facilities, and the Generator should satisfy itself as to any requirements for the protection of its own facilities.

The requirements below are primarily from Appendix F.2 of the Distribution System Code's ("DSC"), Institute of Electrical and Electronics Engineers ("IEEE") Standard 1547, and CAN/CSA C22.2 No. 257-06. Generators are encouraged to consult the listed references for more details about every item. In situations where modifications are required to the incoming supply arrangement, the Generation facility shall also satisfy the following: "Toronto Hydro Requirements for Design and Construction of Customer-Owned Substation High Voltage Substations". It is the Generator's responsibility to ensure that all requirements are met. Additional requirements may be necessary to address unique situations, and Generators will be advised of any additional requirements at the appropriate assessment stage.

Toronto Hydro accepts no responsibility or liability for any of the information provided in this document, which has been provided for informational purposes only. Meeting these requirements does not necessarily constitute an acceptable facility design. Toronto Hydro reserves the right to amend any of these requirements at any time.

1 Connection Impact Assessment – Initial Review

Technical requirements for interconnection of the Generator with Toronto Hydro are checked during the Impact Assessment stage. This initial review is intended to determine the viability of the Generator's project and to provide the applicant an opportunity to evaluate the situation before making further investments.

1.1 Facility Design Overview

1.1.1 Single Line Diagram ("SLD")

For the initial review, a high-level single line diagram of the proposed facilities is required. Major equipment such as the transformer, disconnection device, and the generator and their respective ratings should be included. Please see the *Embedded Generation Connection Application Form* for information to be submitted.

A typical arrangement of a generation facility connected to the utility distribution system is shown below in Figure 1. Various configurations, however, are possible in accordance with design requirements and generation facility use.

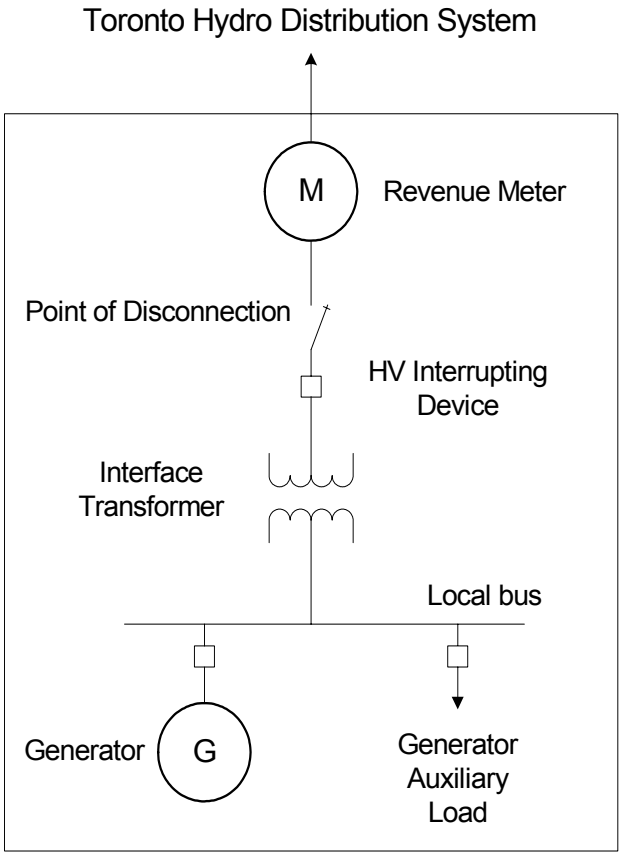

Figure 1 Typical Single Line Diagram Required at the Connection Impact Assessment Stage

1.1.2 Point of Disconnection - Safety

A point of disconnection is required to isolate the embedded generator for the purpose of work protection of Toronto Hydro crews. Switching, lockout and tagging procedures shall be coordinated with Toronto Hydro.

Reference codes and standards that apply to the disconnect or isolation device are as follows: Ontario Electrical Safety Code ("OESC") rule 84-026, IEEE Standard 1547 Clause 4.1.7, CAN/CSA-C22.2 No. 257-06 Clause 5.3.4 and DSC Appendix F.2 Section 1.

1.1.3 Preferred Interface Transformer Configuration and HV Interrupting Device

Preferred configurations for the Generation facility interface transformer are outlined in Table 1. The interface transformer connection significantly affects the generator interaction with the distribution system under steady state and fault conditions. Careful selection and design are required to mitigate adverse effects.

Selecting an appropriate configuration is dependent on the local distribution system at the point of connection. The configurations suggested in table 1 are only general guidelines that are applicable for the majority of connections. Toronto Hydro will assess each connection individually to determine the required configuration based on the local conditions. In situations where generator neutral impedance or a grounding transformer may be required, effective grounding criteria of the distribution system shall be maintained. This will ensure the maximum overvoltage on the distribution system is within 125% of the nominal voltage. The suggested HV interrupting device is a breaker capable of withstanding 220% of the interconnection system rated voltage.

Table 1

System Voltage	Distribution System Grounding Impedance (Low , High)	Preferred Interface Transformer (HV:LV)
27.6, 13.8 kV	Low (effectively grounded)	Wye Ground / Delta
13.8 kV	High (downtown)	Delta / Wye Ground
27.6,13.8 kV, 4.16 kV	Low (effectively grounded)	Wye Ground / Wye Ground (Generation < 1MW)

1.2 Equipment Rating and Requirements	Reference
The generation facility interface equipment shall be compatible with Toronto Hydro equipment design and ratings under all operating conditions. During both on-line and off-line interconnection scenarios of the generation equipment, the distribution equipment shall be within its operating rating. Equipment ratings to be reviewed shall be as follows: - Equipment **thermal loading limits.** This equipment includes feeder conductor/cable, station breaker and transformer ratings. - Impact of generation facility **fault contribution** on equipment rating - If power is to be exported to the distribution system then all **metering devices** shall be suitable for ***bi-directional flow***.	DSC Appendix F.2 Section 5

1.3 Voltage Regulation	Reference
Voltage variations at the point of common coupling ("PCC") are limited to **+/- 6%** of the nominal voltage. The generation facility should not actively regulate the voltage at the PCC. During normal operation, the generation facilities must be **loaded and unloaded gradually** to allow adequate time for regulating devices to respond and avoid excessive voltage fluctuation. The generation facility shall not cause objectionable voltage and current **unbalance** conditions. The generation facility shall not cause voltage unbalance beyond 3% and current unbalance beyond 10% at the PCC.	CSA CAN3-C235 IEEE 1547 Clause 4.1.1 DSC Appendix F.2 Section 3 CAN CSA C22.2 No. 257-06 Section 5.2.3

1.4 Synchronization	Reference
The generation facility shall parallel with the distribution system without causing a **voltage fluctuation** of more than 5% at the PCC. Interconnection shall take place only when the differences in **frequency, voltage and phase angle** are within the limits shown below. **Table 2**	CAN CSA C22.2 No. 257-06 Section 5.3.21 IEEE 1547 Clauses 4.1.3, 5.1.2 DSC Appendix F.2 Section 3.2 OESC rule 84-006

Total DR System Capacity	Frequency Difference	Voltage Difference	Phase Angle Difference
0-500 kVA	0.3 Hz	10 %	20°
>500-1500 kVA	0.2 Hz	5 %	15°
> 1500 kVA	0.1 Hz	3 %	10°

1.5 Feeder Relay Directioning	Reference
To prevent sympathetic tripping of the generator feeder due to faults on adjacent feeders, breaker protection may need a directional feature for reverse fault current conditions.	DSC Appendix F.2 Section 8

1.6 Monitoring	Reference
A generation facility with total capacity rated **greater than 250 kVA** at the PCC, shall have ***provision*** for monitoring items a) to d) below. If monitoring data is not required at the time of connection, the design shall include provisions for future installation. a) Connection status b) Real power output c) Reactive power output d) Voltage at PCC or aggregate connection For a generation facility with total capacity rated **2.5 MW or greater**, items a) to d) shall be ***actively monitored***. In this case, monitoring typically includes status of load interrupting switches, circuit breakers and interface protection annunciation. Communication media options will be mutually agreed upon.	DSC Appendix F.2 Section 9 IEEE 1547 Clause 4.1.6 CAN CSA C22.2 No. 257-06 Clause 5.3.22

1.7 Power Factor	Reference
The generation facility operation shall not adversely affect voltage at the PCC. The preferred power factor range of operation is ±0.9. This range may be narrower if required in some situations. Systems of 30 kW or less are generally not required to be capable of adjusting power factor. For large facilities that are IESO impactive, the generator units shall have sufficient reactive power compensation such that there is no material increase at the transmission system terminal station.	DSC Appendix F.2 Section 4 CAN CSA C22.2 No. 257-06 Clause 5.3.13

1.8 Maximum Power Transfer & Synchronous Stability	Reference
To ensure distribution system stability and prevent adverse effects on the steady state voltage profile of the feeder, the maximum power export of a generating facility shall be limited so as to not exceed 10° phase shift between line ends. For typical distribution feeders on Toronto Hydro's system at 27.6 kV and 13.8 kV the limit is 50 MW and 20 MW, respectively. Other distribution constraints well below these limits however may govern the maximum power transfer such as feeder rated capacity.	Toronto Hydro Requirement

2 Design Review

The design review ensures detailed engineering is in compliance with Toronto Hydro requirements. It is recommended that this review be completed before proceeding with equipment purchase.

A sample single line diagram below provides the details required at this stage.

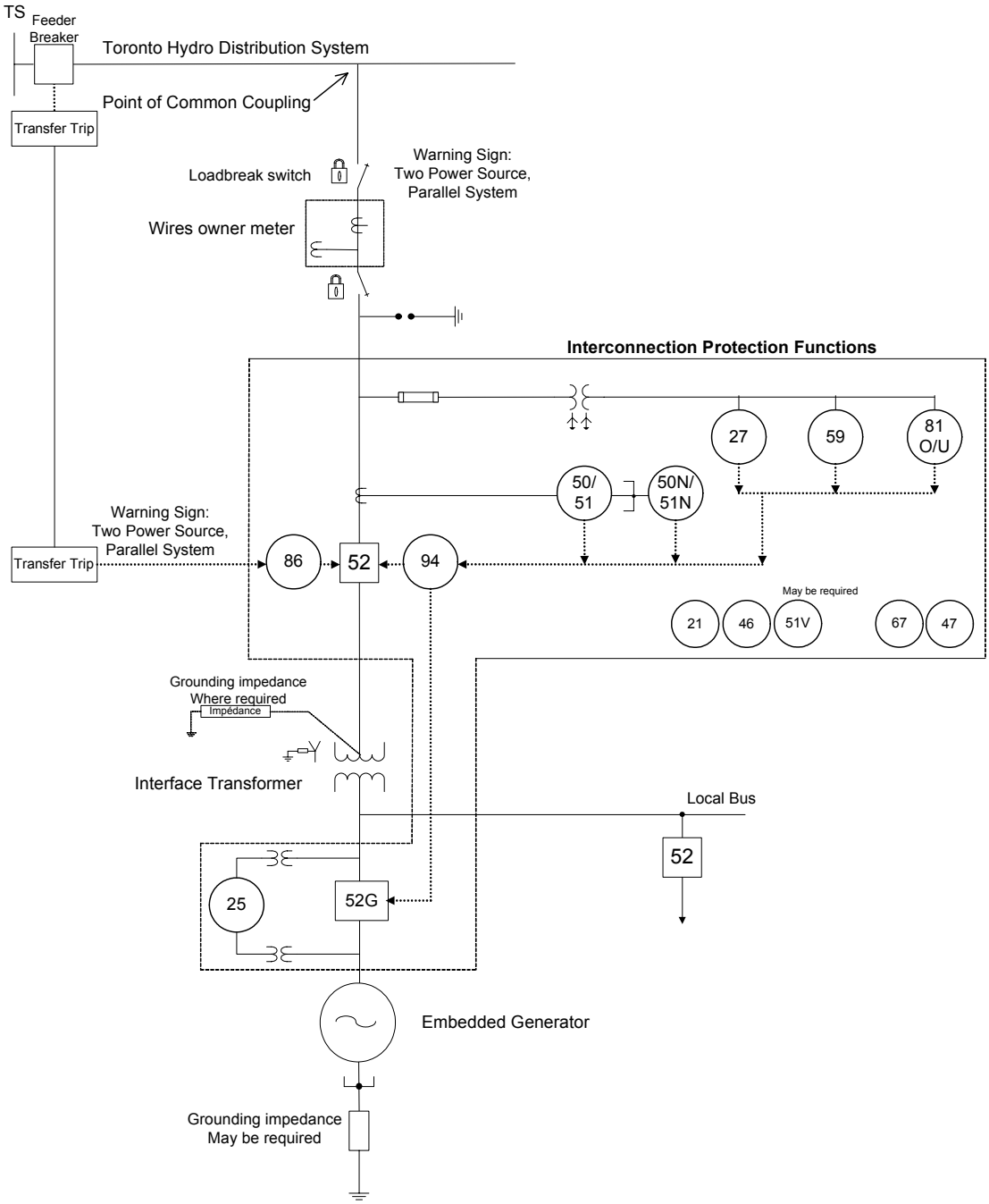

Figure 2 Typical Single-Line Diagram Required at the Design Review Stage

2.1 Cease to Energize	Reference
2.1.1 Distribution System Faults and Customer Facility Faults Interface protection of the generation facility shall **cease to energize** Toronto Hydro's distribution system under the following conditions: **Internal Faults** at the Customer's Facility. **External Faults** on the Toronto Hydro Distribution System. Equipment and Conductors energized from both directions shall have suitable protection from each supply source.	DSC Appendix F.2 Section 6.4 IEEE 1547 Clause 4.2.1 OESC 84-014 CAN CSA C22.2 No. 257-06 Clause 5.3.8
2.1.2 Feeder Breaker Reclosing Coordination The generation facility shall cease to energize Toronto Hydro's feeder before automatic reclosing of the breaker takes place. Toronto Hydro's 27.6 kV feeders incorporate an autoreclose operation typically half a second in duration. Underground 13.8 kV feeders in the downtown area do not have an automatic reclosing scheme.	IEEE 1547 Clause 4.2.2 DSC Appendix F.2 Section 6 CAN CSA C22.2 No. 257-06 Clause 5.2.9
2.1.3 Over-Voltage and Under-Voltage Protection The typical range of protection settings shall comply with the following table: **Response to abnormal voltages**	IEEE 1547 Clause 4.2.3 DSC Appendix F.2 Section 6.5 CAN CSA C22.2 No. 257-06 Clause 5.3.9

Voltage at PCC	Clearing Time Range
V<50%	Instantaneous to 0.16 s
50% ≤ V < 88%	Instantaneous to 2 s*
106% < V ≤ 110%	0.5 s to 2 minutes
110% < V ≤ 120%	Instantaneous to 2 minutes
120% < V < 137%	Instantaneous to 2 s*
137% ≤ V	Instantaneous

* To satisfy system requirements 2 over-voltage and under-voltage set points may be required. The actual clearing times may vary within the above range due to distribution system conditions and generation facility protection design.	Toronto Hydro Requirement
2.1.4 Over-Frequency and Under-Frequency Protection The generation facility shall cease to energize Toronto Hydro's distribution system at the frequency set points and clearing times outlined in the table below. **Response to abnormal frequency**	IEEE 1547 Clause 4.2.4 DSC Appendix F.2 Section 6.5 CAN CSA C22.2 No. 257-06 Clause 5.3.10

Adjustable Set Point	Clearing Time
59.3 to 55.5 Hz	0.1 to 300 s
60.7 to 63.5 Hz	0.1 to 180 s

To satisfy system requirements 2 over-frequency and under-frequency set points may be required.	Toronto Hydro Requirement

2.1.5 Interface Protection System The interface protection study shall include coordination of key interface protection elements, along with the proposed relays and settings to be used at the point of common coupling. The protection study submission shall include required AC & DC schematics and wiring diagram.	DSC Appendix F.2 Section 6 Toronto Hydro Requirement
2.2 Connection to Toronto Hydro System	**Reference**
Connection to Toronto Hydro's System following a grid disturbance shall take place only when the voltage at the PCC is within 6% and frequency between 59.3 and 60.5 Hz. The generation facility shall reconnect no less than 5 minutes after the system has stabilized within the above voltage and frequency ranges. Where multiple units on the same feeder are involved, staggering the reconnection times may be required. For mid-sized generating facilities that incorporate transfer trip protection, a lockout relay (86) shall prevent resynchronization until enabled by Toronto Hydro System Control.	DSC Appendix F.2 Section 6 IEEE 1547 Clause 4.2.6 Toronto Hydro Requirement
2.3 Anti-Islanding Protection and Transfer Trip Requirements	**Reference**
The generation facility shall disconnect from Toronto Hydro's System upon the loss of utility supply voltage in one or more phases. For mid-sized generating facilities with capacity greater than 50% of the minimum feeder load, the design shall include a Transfer Trip scheme to prevent islanding. In this case, Embedded Generator End Open (EGEO) logic is to be included to supervise the autoreclose operation of the feeder breaker.	DSC Appendix F.2 Section 6.1.2 IEEE 1547 Clause 4.4.1 OESC rule 84-008 CAN CSA C22.2 No. 257-06 Clause 5.3.11 Toronto Hydro Requirement
2.4 Grounding at the Generation Facility	**Reference**
The generation facility's grounding scheme shall not cause over voltages that exceed the rating of Toronto Hydro equipment. The distribution system primarily consists of effectively grounded feeders with surge arresters suitably rated. To meet these requirements at the point of connection the following criteria shall be met: $X0 / X1 \leq 3$, $R0/X1 \leq 1$. The generation facility shall not disrupt the coordination of ground fault protection on Toronto Hydro's distribution system. Wind generation facilities shall not connect to the distribution system neutral.	DSC Appendix F.2 Section 2 IEEE 1547 Clause 4.1.2 OESC rule 84-030 CAN CSA C22.2 No. 257-06 Clause 5.3.6 Toronto Hydro Requirement

3 Warning Signs and Diagrams

The following warning sign shall be posted on the point of disconnection, generator feeder cell and switch room door to warn people of the presence of embedded generation:

WARNING
TWO POWER SOURCE
PARALLEL SYSTEM

As well, a single line, permanent and legible diagram of the switching arrangement shall be placed at the **Customer**'s control room and the switch room to indicate the position of the embedded generators and isolation points with their interlocking arrangements.

Operating designations will be assigned to the switching equipment of the generation system as required by Toronto Hydro. The **Customer** shall update the single line electrical diagram and operating diagram to include the assigned operating designations, and the switching equipment shall be identified by the operating designations as well.

4 Commissioning and Witnessing Requirements

The **Customer** shall apply for **ESA** electrical inspection and provide Toronto Hydro with the Certificate of Inspection once requirements are satisfied. Following this Toronto Hydro will also receive a copy of the Authorization to Connect from ESA.

Prior to commencing with commissioning and placing embedded generation facility in-service, Toronto Hydro shall be given an opportunity to review and confirm the proposed commissioning plan meets system requirements.

In addition, before the embedded generator is brought into synchronization, as per the Conditions of Service 4.5.4 and the DSC 6.2.19, Toronto Hydro will require a utility representative to:

- Witness successful tests of the protection system as far as it affects the Interconnection of the embedded generator to the Toronto Hydro distribution system.
- Verify interface equipment and test associated interlocking facilities.

The customer shall advise Toronto Hydro a minimum of fifteen working days in advance of scheduled commissioning tests, exclusive of Saturday, Sunday and Statutory Holidays, to enable Toronto Hydro to witness the commissioning tests. All testing shall be completed during Toronto Hydro's normal working hours with the Customer being responsible for all costs incurred for time spent beyond said hours.

Alternatively, Toronto Hydro may elect to accept a commissioning test report certified by a Professional Engineer. The commissioning verification report shall contain all interface protection settings and confirm key protective functions and interlocking requirements as previously agreed to by Toronto Hydro Policy & Standards Department. The commissioning report shall be submitted for approval before the operation of embedded generation facility.

On small generating units (less than 500 kVA), Toronto Hydro may elect to forego witness testing. All results shall be documented and a copy forwarded to Toronto Hydro.

toronto hydro

TORONTO HYDRO REQUIREMENTS

FOR

THE DESIGN AND CONSTRUCTION

OF

CUSTOMER-OWNED HIGH VOLTAGE SUBSTATIONS

Issued: April 30, 2004
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ENGINEER, POLICY

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MANAGER, POLICY & STANDARDS

CERTIFICATE OF APPROVAL

THIS TECHNICAL SPECIFICATION MEETS THE SAFETY REQUIREMENTS OF SECTION 4 OF ONTARIO REGULATION 22/04

R. Sironi, P.Eng **ROMANO SIRONI, P. Eng.**	**DATE** Jan. 23, 2007

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1. SCOPE

1.1 Toronto Hydro Requirements

This publication covers the design, construction, substation layout and the electrical equipment located in customer-owned high voltage substations. Any exceptions to this publication shall be brought to the attention of Toronto Hydro in writing at the drawing approval stage. The requirements are in addition to the latest edition of:

a) The requirements for the "Supply Authority" as covered in the Ontario Electrical Safety Code;
b) The "Conditions of Service" published by Toronto Hydro;
c) The “THESL Requirements for Customer-Owned Structures”
d) The “Toronto Hydro General Requirements for Parallel Generation” in the Conditions of Service;
e) The “Toronto Hydro Metering Requirements for 13.8kV & 27.6kV Customer-Owned Substations”;
f) Associated Publications in section 11.

1.2 Enclosed Switchgear

These requirements cover metal enclosed (indoor or outdoor) switchgear. Open type switchgear may be acceptable if appropriate protective and gang-operated isolating device(s) is installed between the Customer facility and Toronto Hydro system. Additional conditions on metering may be required for open-type switchgear.

1.3 Ontario Electrical Safety Code and Ontario Building Code

Unless exceptions are granted by the governing Authorities, nothing contained in these requirements shall prejudice or supersede any regulations or requirements of the Ontario Electrical Safety Code and Ontario Building Code.

1.4 SI Units

All dimensions and weights are stated in metric units. Equivalent measurements will be accepted if equipment or materials are not manufactured in metric units.

2. PURPOSE

These requirements are intended to provide guidance to Toronto Hydro Customers in designing and constructing 13.8kV or 27.6kV Customer-Owned Substations for the purpose of:

(a) Assuring safe conditions for Customer and Toronto Hydro personnel in operating and maintaining Customer-Owned Substations.

(b) Assuring a continuity of supply to all customers by the use of adequate specifications and proper design factors.

3. DEFINITIONS

Acceptable	Meets Toronto Hydro requirements.
Approval	Approval of drawings and customers' equipment is limited to Toronto Hydro's requirements and does not construe as acceptance of liability arising from faulty design or workmanship.
Compartment	A subdivision of a unit.
Customer	Means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub.
Customer-owned Substation	A customer-owned civil structure accommodating customer-owned electrical equipment connected to Toronto Hydro 13.8kV or 27.6kV system.
Embedded Generation Facility	Means a generation facility which is not directly connected to the IMO-controlled grid but instead is connected to a distribution system.
Embedded Generator	A generator whose generation facility is not directly connected to the IMO-controlled grid but instead is connected to a distribution system.
Emergency Backup Generation Facility	Means a generation facility that has a transfer switch that isolates it from a distribution system.
Exit	A path of travel which leads from a floor area to a separate building, an open public thoroughfare or an exterior open space which is protected from fire exposure from the building and has access to an open public thoroughfare.
High Voltage	In this document context, high voltage means 13.8kV or 27.6kV.
IMO	Independent Electricity Market Operator
Means of Egress	A means of egress is a continuous path of travel provided for the escape of persons from any point in a building or contained open space (i.e. Substation) to an open public thoroughfare. The means of egress includes the exit and the access to the exit.
MSG	Manufacturer's Standard Gauge for uncoated steel.
Sprinkler-Proof Enclosure	An enclosure for indoor application so constructed or protected that water from sprinkler systems will not interfere with the successful operation of the enclosed switchgear, excluding flooding.

Switchboard	Switchboard means a switchgear assembly that consists of one or more panels upon which are mounted switching control, meters and protective regulatory equipment and in which the panel or panel supports may also carry the main switching and interrupting devices together with their connections.
Unit (Switchgear)	A full height and full depth module of a switchgear assembly. It is sometimes referred to as “cell”, “cubicle”, “section” or “enclosure”.
Vault (Transformer)	An isolated enclosure with fire-resistant walls, ceiling and floors, for the purpose of housing transformers and other electrical equipment.

4. EXTENT OF TORONTO HYDRO JURISDICTION

4.1 Point of Entry to Protective Devices

For the purpose of these requirements, Toronto Hydro jurisdiction normally covers the equipment between the point of entry of the supply cables into the Customer’s property and the load side of the first protective devices, i.e. fuses or circuit breakers.

4.2 Jurisdiction Coverage Extension

Toronto Hydro jurisdiction is extended beyond the above limits to cover:

(a) Toronto Hydro metering equipment when located on the load side of the first protective devices.

(b) Protective devices located on the load side of the first protective devices in cases where the first protective devices cannot function as required with the Toronto Hydro feeder protection.

(c) Interlocks intended to prevent paralleling the Toronto Hydro incoming lines when located beyond the area described in 4.1.

(d) Interlocks which prevent the paralleling of an Emergency Backup Generator with the Toronto Hydro Supply.

(e) Any equipment which may affect the safety of Toronto Hydro personnel.

(f) For safety and security reasons, the Customer must obtain approval from Toronto Hydro before operating the incoming load break switches or circuit breakers.

5. METHOD OF SUPPLY

The conditions of supply for Customer-Owned Substations are outlined in section 2 of Conditions of Service.

5.1 Number of Feeders

5.1.1 One-Feeder Supply

Typical one-feeder supply arrangements are shown in sketches 1(b) and 1(c).

5.1.2 Two-Feeder Supply

Typical two-feeder supply arrangements are shown in sketches 1(d) to 1(h).

With two-feeder supply, the feeders are not permitted to operate in parallel. One feeder (Normal) will normally carry the total customer's load and the other (Standby) will remain open on potential. Automatic Transfer Switch may be installed to improve reliability (refer to 5.2 and 9.19).

If a split-bus arrangement [sketch 1(h)] is employed, each of the two feeders can carry its own load but the tie-switch (or tie-breaker) must be open to prevent paralleling of the two feeders. In this arrangement, Customer must ensure that the transformer secondaries on either side of the split-bus be electrically separated (not paralleled).

The Customer shall not install any equipment to permit electrical connection between transformer secondaries across the split bus.

5.1.3 Three or More Feeder Supply

When three or more feeders are designed to operate in parallel, circuit breakers and pilot wire relay protection and remote trip receiving relay shall be required [refer to sketch 1(i)].

Pilot wire relay protection arrangement is provided at the sole discretion of Toronto Hydro. Additional conditions and premium costs may apply.

5.2 Automatic Load Transfer (Automatic Transfer Switch).

Subject to Toronto Hydro approval, an automatic load transfer may be employed where the Customer requires a higher degree of service reliability than that afforded by other methods of supply. Each feeder is connected to the Customer's switchgear through a circuit breaker (or motorized loadbreak switch) one of which is normally closed and carrying load, the other open and on potential. Automatic transfer is initiated on a voltage sensing basis, the voltage sensing being obtained from potential transformers located on the source side of incoming feeder breakers (or motorized loadbreak switch) (Refer to 9.19 for details).

5.3 Feeder Termination

Each feeder shall be terminated in the Customer's switchgear and shall be connected to the Customer's bus either through a circuit breaker equipped with a primary disconnecting device or through a loadbreak switch [refer to sketches 1(b) through 1(h)].

5.4 Duplicate Metering

Where a Customer has a two-feeder arrangement [Normal and Standby, Refer to sketch 1(g)] that requires dual metering, the Customer shall be responsible for the additional metering cost.

6. PROCEDURE FOR OBTAINING TORONTO HYDRO APPROVAL

Following acceptance of a Customer's application for a 13.8kV or 27.6 kV supply or a proposal to modify an existing 13.8kV or 27.6kV substation, the procedure shall be as follows:

6.1 Drawings

The Customer shall submit to Toronto Hydro for approval the drawings and information listed in Section 7.

6.2 Additional Drawings

If the drawings or information do not meet Toronto Hydro requirements or are not sufficiently clear, then revised or additional drawings and information must be submitted on request.

6.3 Manufacture of Equipment – Drawing Approval

Manufacture of equipment should not start until all drawings and information have been approved by Toronto Hydro. This will avoid costly changes to completed equipment. Final revised l drawings must be delivered to Toronto Hydro at least four weeks prior to the delivery of the switchgear to the substation site.

6.4 Inspection of Equipment Prior to Shipment

Toronto Hydro reserves the right to inspect the completed equipment at the manufacturer's plant prior to shipment.

6.5 Compliance with Requirements

When the installation of the switchgear has been completed, the customer shall utilize a qualified testing agency and subject the switchgear to a Dielectric Strength Test. The voltage applied shall be 75% of the factory test voltage in accordance with clause 8.6.1 of CSA Standard C22.2 No. 31 "Switchgear Assemblies". Toronto Hydro shall witness

the testing of the switchgear by the qualified testing agency during normal working hours. Notice of witness testing date shall be submitted to Toronto Hydro at least 2 weeks in advance. A test report certified by a Professional Engineer shall be submitted for approval before the energization of switchgear.

6.6 Additional Dielectric Strength Tests

Should the switchgear fail to pass the Dielectric Strength Test, the Customer shall make the necessary modifications and a further dielectric test shall be performed.

6.7 Dual Locks

A u-bolt dual locking facility is required on the operating handle of the incoming switchgear to allow locking in the open or closed position. Either Toronto Hydro or the Customer can open the lock. The Customer must consult Toronto Hydro before any closing operations.

6.8 Automatic Transfer Relay Settings

Where circuit breakers or automatic transfer switches are used, Toronto Hydro personnel shall witness the setup of the relays and the testing of the protection and control devices for correct operation of these devices.

6.9 Pre-Service Inspection Report and Final Connection

A pre-service inspection report shall be submitted to Toronto Hydro for approval prior to final connection of supply to Customer substation. Toronto Hydro reserves the right to carry out additional inspections. A Connection Authorization from the Electrical Safety Authority is also required prior to final supply connection.

The pre-service inspection report shall include the following items and shall have a conclusion on whether or not the substation is satisfactory for energization.

6.9.1 As Constructed Drawings

The pre-service inspection contractor shall have a Professional Engineer certify that the customer's installation was completed in accordance with the original drawings that were approved by Toronto Hydro and return a set of these drawings to Toronto Hydro to keep on file as "As Constructed" drawings. The drawings to be certified must be original, photocopies are not acceptable. Refer to section 7 for drawings and information required for approval.

6.9.2 Transformer and Cable Tests Requirements

The following transformer and cable tests shall be certified by a Professional Engineer:

6.9.2.1 Transformer Test Requirements

- Turns Ratio (all taps)
- Insulation Resistance (Mega-Ohms for 60 seconds, indicate test voltage)

6.9.2.2 High Voltage Cable Test Requirements

Test voltage applied as follows: Duration shall be 15 minutes with leakage reported in microamperes at 1-minute intervals.

System Voltage	Test Voltage
13.8 kV AC	54 kV DC
27.6 kV AC	86 kV DC

7. DRAWINGS AND INFORMATION REQUIRED FOR APPROVAL

Five copies of each of the drawings and information listed in 7.1 to 7.6 inclusive shall be submitted to Toronto Hydro for the attention of CFDC (Customer Facilities Design & Construction) Department, unless otherwise advised, for approval. Additions and modifications to existing equipment shall be clearly indicated.

All drawings shall be approved and stamped by a Professional Engineer before submission to Toronto Hydro for review.

Drawings shall be fully dimensioned and scaled. Photo-reduced copies of the original and unapproved drawings shall not be accepted.

All dimensions shall be in S.I. units.

7.1 Substation Drawings

Drawings shall indicate:

(a) Site Plan: The location of the substation relative to buildings, structures, property lines, the nearest public thoroughfare, and other equipment in the vicinity of the substation including vehicular and personnel access route.

(b) The proposed route of Toronto Hydro incoming supply cables, including details of primary duct bank.

(c) The location of any pipes or ducts in the vicinity of the substation, e.g. ventilating ducts, water, gas, sewage pipes, sprinkler system, access openings, windows, vehicle access, access direction, etc.

(d) Layout of the equipment in the electrical room clearly indicating aisle clearances and exits.

(e) Details of cable pits, ducts or vaults.

(f) Details of substation grounding arrangements and location of any ground grids used.

(g) Details and location of meter cabinet. Refer to Metering Diagrams #1, #2, #3 and the Conditions of Service.

7.2 Single Line Diagram

The following information shall be included in the drawing:

(a) Ratings, impedances and taps of the main transformers.

(b) Ratings and short circuit capabilities of circuit components.

(c) Details of all primary cables e.g. voltage, size, material, etc.

(d) Interlocking arrangements with an explanation of operational sequences.

(e) Proposed protective relaying scheme, where applicable, showing relay types and instrument transformer ratios and accuracy.

7.3 Specifications of Electrical Equipment

These shall include dimensions, ratings, manufacturer, type, and other technical information.

7.4 Switchgear Assembly Drawings

Drawings shall provide the following information:

(a) Plan, elevation and sectional views (front and side) of the switchgear assembly including working clearances.

(b) Grounding details. (Refer to 9.18.)

(c) Provisions for Toronto Hydro metering equipment. (Refer to Section 10 and the Conditions of Service)

(d) Provisions for access to components. (Refer to 9.4 and 9.5.)

(e) Description of principal components.

(f) Details of barriers (Refer to 9.8.)

(g) Electrical clearances (Refer to 9.16.)

(h) Interior paint finish (Refer to 9.2.5.)

(i) Name plate.

(j) Interlock scheme and dual lock provision.

7.5 Single Line and Schematic Wiring Diagrams

These shall include AC single line and DC schematic drawings and connection wiring diagrams of the protection and control equipment used in conjunction with circuit breakers and motor operated switches. [Refer to sketch 5].

7.6 Protection Co-ordination Study

All customers' devices associated with the 13.8kV or 27.6kV equipment shall coordinate with Toronto Hydro upstream protection. Toronto Hydro shall provide upstream protection information as required. Customer shall submit a protection coordination study report to Toronto Hydro for approval.

7.7 Final Documents

The Customer shall submit the final documents mentioned above to Toronto Hydro for approval. Failure to provide Toronto Hydro with the final documents may delay the substation connection to the Toronto Hydro supply system.

8. SUBSTATION REQUIREMENTS

8.1 General Requirements

The substation shall be constructed and equipped in accordance with the relevant standards, governmental codes and regulations.

The substation shall be located on the ground level. If a suitable ground level location is not available, Toronto Hydro may accept a below-grade location, provided the location is immediately one floor below the ground level.

8.2 Exits and Doors

8.2.1 Means of Egress and Exit Door Requirements

Two separate means of egress each with an Exit door and located at opposite side of the substation area are required. Each means of egress shall allow a separate escape route to exit from any point in the substation area to an open public thoroughfare.

The doors shall be fitted with a keyed cylinder lock and installed on the opposite side of the panic type bar, all to be acceptable to Toronto Hydro.

Each exit door shall be equipped with an EXIT sign.

Entrance and exit doors must remain clear of obstructions at all times.

8.2.2 Legislation and Specific Requirements

The exits shall conform to the latest revision of the Ontario Building Code and "The Ontario Occupational Health and Safety Act, and Regulation for Industrial Establishments – Part II – Buildings" from which the following are extracted:

(a) OHSA Rules 122 states that:

(1) This section applies with respect to a hazardous room,

(a) With an area greater than fifteen square meters; or

(b) Requiring a distance of travel greater than 4.5 m from any point in the room to an egress doorway.

(2) A hazardous room shall be located in a floor area that has at least two exits.

(3) A hazardous room shall have at least two egress doorways that are at least three-quarters of the length of the diagonal distance of the room from each other.

(4) One egress doorway must be located within a maximum distance of twenty-three meters from any point in a hazardous room."

(b) If doors are used they shall open in the direction of exit travel and swing on their vertical axes. [Direction of Door Swing – Ontario Building Code, latest edition].

(c) The door(s) must open readily from inside the room at all times it is occupied. Locks shall not require a key to operate from inside.

(d) Where more than one door is employed, all doors shall be equipped with panic hardware.

(e) Doors equipped with panic hardware must open under 90N releasing pressure applied in the direction of exit travel. [Door Release Hardware – Ontario Building Code, latest edition]

(f) Panic hardware must be located between 0.76 m and 1.12 m above floor level on room doors.

Note: Where double doors are used; only one of the pair requires panic hardware.

(g) Where the exit doors open into an area where the means of egress may be impeded by vehicular traffic, protective removable bollards shall be installed by the customer.

(h) Cable Pull Room Doors – Class B (3/4 hr) fire doors or better shall be supplied and installed by the customer. For cable installations over 750V – "High Voltage" warning signs shall be installed on the door. The fire doors and frames, ventilating shafts or louvered windows for ventilation are to be grounded.

8.3 Cable Pulling

Cable pulling loops or eyes shall be installed by the Customer opposite the incoming duct faces in Customer's electrical room, pull room or cable chamber. In addition, the following shall be adhered to:

(a) Where the service entrance must be in such a location that underground cables cannot be pulled directly into the electrical room, the customer shall provide an acceptable cable pull room, or cable chamber to be used as an intermediate pull location. [Refer to the Toronto Hydro Requirements for Customer-Owned

Structures (Toronto Hydro Standards 31-6000, 31-6010, 31-6020, 31-6030, 31-6040, 31-6050, 31-6060 and 31-6080)].

(b) Clearance for pulling cable – In all circumstances, space must be available for a straight cable pull between the duct face and the pulling loop or eye. Where there is less than 3.0 m clear space from the duct face to the pulling loop or eye, every effort should be made to locate the room door in the wall opposite the duct face. If a door is not practical, an opening close to the floor level and with a removable cover should be provided in the wall containing the pulling loop or eye.

8.4 Cable Racks and Conduits

(a) Where required, cable supports, racks, and mechanical protection shall be supplied and installed at the customer's expense.

Conduit installations on Customer's premises for Toronto Hydro incoming cables shall conform to Toronto Hydro's standard practices. [Refer to the Toronto Hydro Requirements for Customer-Owned Structures (Toronto Hydro Standards 31-6000, 31-6010, 31-6020, 31-6030, 31-6040, 31-6050, 31-6060 and 31-6080)].

(b) The maximum length of the cable from the duct face to the customer owned switchgear shall not exceed 7.5 m. The installation shall meet the requirement of Ontario Electrical Safety Code rule 36-100.

8.5 Outdoor Substations – Fence and Gates

(a) Guarding of Electrical Equipment

All outdoor substations shall be surrounded by guarding fence and gates in accordance with OESC rule 26-302 to 26-324 and section 8.6.

(b) Height of Fence

The fence, excluding barbed wire, shall not be less than - 1.8m high.

(c) Barbed Wire

The fence shall be topped with not less than three strands of barbed wire.

(d) Gates

(i) Gates shall preferably open outwardly but, if it is necessary that they open inwardly, they shall not come into contact with the frame or enclosure of any electrical equipment when fully opened; a clear passageway at least 0.9 m wide and 2.2 m high shall be maintained to ensure safe egress.

(ii) Double gates with center stops shall be used where the width of opening exceeds 1.5 m.

(iii) All gates shall have security provision for accepting both Customer and Toronto Hydro padlocks; also, "High-Voltage Warning" signs shall be affixed to them.

(e) Grounding
Substation grounding shall meet the requirements of Ontario Electrical Safety Code, 36-300 to 36-312.

8.6 Safe Working Space
Safe working space in vicinity of service entrance equipment including metering shall be in accordance with the Ontario Electrical Safety Code Rule 2-308 and shall include the following:

8.6.1 Working Space About Equipment

(a) A minimum working space of 1.0 m with secure footing shall be provided and maintained about electrical equipment such as switchboards, panel boards, control panels and motor control centres which are enclosed in metal, except that working space is not required behind such equipment where there are no renewable parts such as fuses or switches on the back and where all connections are accessible from locations other than the back. (Also refer to 8.6.2 for Toronto Hydro clearances.)

(b) The space referred to in 8.6.1(a) shall be in addition to the space required for the operation of draw-out type equipment in either the connected, test, or fully disconnected position and shall be sufficient for the opening of enclosure doors and hinged panels to at least 90º.

(c) Working space with secure footing not less than that specified in Table 56 of Ontario Electrical Safety Code – Minimum Working Space About Electrical Equipment Having Exposed Live Parts, shall be provided and maintained about electrical equipment such as switchboards, control panels and motor control centres having exposed live parts.

(d) The minimum headroom of working space about switchboards or motor control centres where bare live parts are exposed at any time shall be 2.2m.

8.6.2 Minimum Space Requirement
A minimum of 1.5 m. shall be provided in front of all doors giving access to switchgear components and where Toronto Hydro is required to work.

8.6.3 Side or Rear Access Panels
Where removable side or rear access panels are required, a minimum working space of 0.9 meter with 2.2 m clear headroom shall be maintained.

8.6.4 Aisle Space
A clear passageway at least 0.9 m wide and 2.2 m high shall be maintained as an exit route from all service entrance equipment. This headroom must also be maintained in the working space in the vicinity of the service entrance equipment.

8.6.5 Blocking of Exit Route

Where the compartment hinged doors or drawout components would block the exit route then a clear minimum space of 0.6 m must be maintained from the edge of the access door or components in the fully open position.

8.6.6 Illumination of Equipment

Adequate illumination shall be provided to allow for proper operation and maintenance of electrical equipment in accordance with Ontario Electrical Safety Code Rule 2-314. The lighting shall be controlled by wall switches located at the entrances to these areas.

8.6.7 Accessibility for Maintenance

Passageways and working space around electrical equipment shall not be used for storage and shall be kept clear of obstruction and so arranged as to give authorized persons ready access to all parts requiring attention in accordance with Ontario Electrical Safety Code Rule 2-312.

8.7 Access to Substation by Toronto Hydro

Immediate access to the substation must be provided on a 24-hour basis for Toronto Hydro personnel. A door equipped with a Toronto Hydro lock, giving direct access to the substation from the outside (e.g. street) shall be provided where practicable. Alternatively the doors along the route leading to the substation must be equipped with Toronto Hydro locks.

If Toronto Hydro locks are not practical, the customer shall provide Toronto Hydro the appropriate access keys or magnetic cards to enable entry from outside (e.g. street) to the substation. Toronto Hydro shall supply and install a key box at a suitable location to safekeep the key(s).

8.8 Communication Lines

Where the customer's electrical room is located such that radio communication with the Toronto Hydro Control Centre is not adequate; the customer shall provide a telephone in the electrical room.

8.9 SF6 Switchgear

Where SF6 switchgear is installed inside the substation, a means of annunciation of low SF6 gas pressure shall be provided to the outside of the substation. This annunciation shall consist of an external warning light installed above each access entrance. A sign stating "Low SF6 Gas Pressure" shall be mounted above the external warning light. A "Lamp Test" button shall be installed on the external annunciation unit for means of testing the warning light before entering the substation. [Refer to 9.23(e)]

8.10 Power Supply

A 120V a.c. 15-ampere 2-pole 3-wire grounded receptacle shall be provided close to Toronto Hydro's incoming feeder compartment. If installed outdoors, the receptacle shall be weatherproof and protected by a ground fault circuit interrupter of the Class A type.

8.11 Single Line Diagram

The Customer shall provide and post a mounted single line diagram (latest revision) of good quality print on a wall in the electrical room for reference. The Customer shall also update the single line diagram to include those switching equipment designations that may be assigned from time to time by Toronto Hydro.

9. EQUIPMENT REQUIREMENTS

9.1 System Parameters/Ratings

Customer equipment shall conform to ratings in Table 1 below:

Table 1. System Parameters/Ratings.

Requirement	13.8kV	27.6kV
Rated Continuous Current (min)	600 A	600 A
Rated Nominal Voltage	13.8kV	27.6 kV
Rated Load Interrupting Capability	600A	600A
Rated Maximum Voltage	15kV	29.3 kV
Rated Frequency	60 Hz	60 Hz
Power Frequency Withstand Voltage	36 kV	45 kV
Basic Impulse Level (BIL)	95 kV	125 kV (Grd. Y)
Rated System Fault Level (MVA sym)	500 MVA	800 MVA
3-phase Symmetrical Fault Current (rms)	21kA	17kA
Rated Momentary Current (rms asym)	34 kA	27 kA
Fault Closing Current (10 Cycles, rms, asym)	40kA	27kA
Short Time Withstand Current (rms, sym)	25 kA (2 seconds*)	25kA (1 second)
Single Line-to-Ground Fault Current (rms)	11kA	12kA
Corona Extinction Voltage to Ground	10.5kV	19 kV
Circuit Breaker Operating duty	CO–15 sec–CO	CO–15 sec–CO
Circuit Breaker Opening Time	5 cycles	5 cycles

* 1 second rating is acceptable for feeders not from former Toronto area subject to Toronto Hydro's approval

Any deviation from the above ratings must be brought to Toronto Hydro's attention.

9.2 Enclosures

9.2.1 Sheet Steel Enclosures

All enclosures including barriers between compartments containing high voltage components shall be of sheet steel not less than #11 MSG and all other covers, barriers, panels and doors shall not be less than #14 MSG.

9.2.2 Electro-magnetic Effects

To avoid heat generation due to electromagnetic effects when a single conductor or bus penetrates through a magnetic material, stainless steel barriers shall be

used. Aluminum barriers are not acceptable. Also, refer to Section 9.7.2 (c) (ii) for requirements on strain relief connectors.

9.2.3 Design of Enclosures

The switchgear enclosure shall be designed in accordance with the rules of the Canadian Electrical Code, Part I and as defined in latest CAN/CSA Standard C22.2 No. 94. Heaters shall be used in the switchgear and shall be controlled by humidistat.

9.2.4 Ventilation

Ventilating openings, if required, shall be designed to prevent the entrance into the enclosure of any object, which could come into hazardous proximity to live parts.

9.2.5 Enclosure Interiors

Interiors of enclosures shall be finished in white enamel.

9.2.6 Mimic Bus

A mimic bus on front door of switchgear compartment with no rear access shall indicate the internal electrical arrangement of equipment in each compartment. The mimic bus shall be securely fastened to the panel. For switchgear with rear access, all components, both front and rear, shall be marked and labeled similarly.

9.2.7 Name Plates

Switchgear data nameplates shall be engraved or stamped and mounted in accessible location. Photographic imprinting process is not acceptable.

9.3 Compartmentation

9.3.1 Separate Compartments

The following switchgear components shall be installed within separate compartments formed by sheet steel barriers:

(a) Each loadbreak switch.

(b) Each incoming cable termination.

(c) Each group-operated isolating switch.

(d) Each circuit breaker.

(e) Each three-phase set of power fuses.

(f) Each set of metering current transformers.

(g) Each set of voltage transformers.

(h) Each set of metering voltage transformer fuses.

(i) Where a bus transition from the bottom of the switchgear to the top of the switchgear is required, the transition shall be done in a separate compartment [refer to 9.3.4(b)].

(j) Where an interface connection is required between the main switchgear bus, and a power transformer in an adjacent compartment, a full metal barrier complete with fully rated through-bushings shall be provided to establish complete segregation of the two compartments.

9.3.2 Compartment and Openings

There shall be no openings whatsoever in compartment walls that shall permit the flow of ionized gases or flame into adjacent compartments.

9.3.3. Intercompartmental Primary Connections

Where the primary connections pass from one compartment to another compartment, the through-bushings installed in metallic barriers shall be rated fully at the same insulation level as the switchgear. Insulating material between compartments is not permitted.

9.3.4. Exceptions

(a) If the incoming feeders enter the switchgear from the bottom, a single compartment may contain both an incoming cable termination and either a loadbreak switch or an isolating switch provided the switch and all buses are located above the cable termination and the compartment has two access doors, one in front of the switch and one in front of the cable termination. However, a single door may be accepted if a hinged screen door is installed behind the access door. (Refer to 9.5.1(a) and 9.8.2).

An additional warning sign “CAUTION, SWITCH BLADES COULD BE LIVE” shall be posted either on the top access door accommodating the incoming line switch in case of two access doors compartment or on the hinged metallic screen door covering the incoming line switch in case of single access door compartment.

(b) When the transition bus is in the same compartment as the loadbreak switch and separated from the incoming cable termination compartment, a separate compartment is not necessary.

(c) If a set of power fuses is immediately preceded by a loadbreak switch other than an incoming line switch, then both may be contained in a single compartment provided the switch and all preceding buses are located above the power fuses, and the compartment has two access doors, one in front of the switch and one in front of the fuses. However, a single door may be accepted if a hinged screen door is installed behind the access door (Refer to 9.5.1(b) and 9.8.2).

(d) Fixed fuse supports used in conjunction with the metering voltage transformers may be mounted in the same compartment as the metering current transformers provided the current transformers and all main buses are located above the fuse supports. Two access doors, one in front of the fuse supports, may be used or alternatively a single access door may be

used for the compartment. A separate access door is required for the metering voltage transformers.

(e) Where voltage transformers, for other than revenue metering purposes, are mounted on a drawout or swing-out type carriage their fuses may be mounted on the carriage in the same compartment.

(f) For 27.6kV switchgear metering, the current transformers and voltage transformers can be installed in the same compartment. Barriers and voltage transformers fuses are not required.

9.4 Access Doors (Also refer to 9.5)

9.4.1 Doors for Compartments

Individual hinged access doors are required to give access to the following compartments:

(a) Each loadbreak or isolating switch.

(b) Each circuit breaker.

(c) Each set of power fuses.

(d) Each set of metering current transformers.

(e) Each set of voltage transformers.

(f) Each set of voltage transformer fuses.

(g) Each incoming feeder cable termination.

9.4.2 Hinged Access Doors

All hinged outer access doors shall open at least 135° and all hinged inner doors or screens shall open at least 90°.

9.4.3 Padlock Hasps

Access doors shall be equipped with padlock hasps measuring at least 30mm wide and 5mm thick capable of accepting a standard Toronto Hydro padlock with a 8mm shackle.

Padlock hasps are not required:

(a) On access doors equipped with interlocks that prevent access to live components.

(b) On access doors to withdrawable circuit breaker compartments.

9.4.4. Securing Access Doors

Access doors shall be adequately secured with either 25mm knurled head captive bolts that require no tools to unscrew, or handles with at least three latching points. For outdoor installation, shrouded penta-head bolts are acceptable alternative.

9.4.5 Stops on Access Doors

Access doors on compartments shall have stops to hold the doors in the fully open position.

Hinged or removable panels other than the access doors specified herein which provide access to high voltage components shall be secured with tool operated screws.

9.5 Screen Doors (also refer to 9.4)

9.5.1 Single Access Doors

In the following cases a single access door may be used in lieu of two separate doors provided that it covers the entire opening and a hinged metallic screen is installed behind the single door as described below:

(a) To cover an incoming line switch installed in the same compartment as a cable termination in accordance with 9.3.4(a).

(b) To cover a loadbreak switch installed in the same compartment with a set of power fuses in accordance with 9.3.4(c).

9.5.2 Screen Approval

(a) Installations using metallic screens according to 9.5.1 will be subject to special Toronto Hydro approval that requires the screens to be hinged, bolted and padlocked and have a high voltage warning sign affixed to them. A screen must fully cover the opening, which would normally be covered by the upper of the two separate doors, and there shall be no openings larger than 13mm in or around the screen. (Refer also 9.8.2.)

(b) Refer to 9.3.4(a) for additional warning sign in case of bottom entry incoming feeder cables.

(c) All screens shall be painted flat black.

(d) Screens must allow all components to be clearly seen.

9.6 Viewing Windows

Windows of 13mm thickness Lexan clear polycarbonate sheet or equivalent shall be provided to permit the observation of all switchblades, voltage indicators and incoming cable terminations with the access door closed.

Note: The polycarbonate sheet shall be bolted to the inside of the door surface and there shall be a minimum of 13mm overlap with gasket in between.

9.7 Toronto Hydro Incoming Feeder Terminations

9.7.1 Types of Cables and Terminations

(a) Toronto Hydro will normally supply and install cable from the supply point (on the street) to the termination point on the Customer's switchgear. The cables could be either PILC or polymeric.

(b) Where paper insulated lead covered cable (PILC) is used, the Customer's switchgear shall have provision for Class 1 terminations (potheads) as defined in the latest edition of IEEE Standard 48. Refer to sketch 2 for clearance requirements.

(c) Where single conductor polymeric-insulated cable is utilized, the Customer shall provide space and clearance as shown on sketch 2 so that Class 1 terminations such as heat shrink or cold shrink termination kits can be installed.

9.7.2 Scope of Materials Supply

(a) Materials Supplied by Toronto Hydro for PILC and Polymeric Cables
Toronto Hydro will normally supply the following materials:

(i) Class 1 terminations (potheads – Toronto Hydro standard design) for PILC cables.

(ii) Class 1 terminations (heat shrink or cold shrink kits) for polymeric cables.

(iii) Standard 2-hole NEMA lugs for terminating polymeric cables.

(iv) Strain relief connectors of non-magnetic material for single conductor cables.

(b) Materials Supplied by the Customer for PILC Cables

(i) Aerial lugs (G&W Electric Co. Style 8)
Use of non-standard aerial lugs to suit particular switchgear design must be approved by Toronto Hydro.

(ii) Non-standard Class 1 terminations, such as angled potheads, to suit particular application.

(iii) The mounting plates and gaskets for top entry terminations. [Refer to sketch 3].

(iv) Flexible tinned copper braids, drilled to suit aerial lug and switchgear terminal pad, as well as associated bolting accessories.

The braids shall have sufficient slack between the bolted ends to absorb longitudinal and lateral motion.

(v) For standard pothead installation, the Customer shall provide three aerial lugs and three copper braids as spare and shall store in a readily accessible location within the Customer's electrical room.

For non-standard (angled) pothead installation, the customer shall provide one pothead in addition to the items above.

(c) Materials Supplied by the Customer for Polymeric Cables

(i) Bus terminal lugs and bolting accessories, if other than standard 2-hole NEMA lugs, suitable to terminate Toronto Hydro cables on switchgear terminal pad (Toronto Hydro shall provide size of conductors).

(ii) Gland plate of non-magnetic material for single conductor cables.

9.7.3. Bottom Entry Cables

(a) PILC cable installations shall have the wiping sleeve of the pothead mounted at least 0.3m above the base of the switchgear and 1.2m above the floor of a cable trench. (Refer to sketch 2, figure 1) Adequate clearance shall be furnished between the aerial lug and the switchgear terminal pad for ease of connection of copper braid.

(b) Polymeric-insulated cable terminations require a minimum vertical distance of 1.0m from where the cable enters the switchgear to the terminal lug. (Refer to sketch 2, figure 2).

(c) Where a cable trench is used, removable plate shall be installed at the base of each incoming feeder compartment. These shall cover the entire bottom opening of the compartment. Cable entry shall be through a gland plate of non-magnetic material (stainless steel) for single conductor polymeric cables. The minimum depth of the trench shall not be less than 0.9m.

9.7.4 Top Entry Cables

(a) For PILC cables, the minimum clearance required above the switchgear is shown on sketch 2, figure 3. Where there is insufficient headroom to accommodate specified clearance, the Customer shall provide suitable Class 1 terminations (angled potheads) and a minimum clearance of 915mm between the top of the switchgear and the ceiling.

(b) For single conductor polymeric cables, the terminations require a minimum vertical distance of 0.6 meter between the cable entrance to the equipment and the terminal lug. (Refer to sketch 2, figure 4). A removable non-magnetic (stainless steel) gland plate shall be provided at the top of the switchgear.

9.8 Barriers

9.8.1 Requirement for Barriers

Phase to phase and phase to ground barriers (see 9.8.3) shall be installed on the following equipment:

(a) Each loadbreak switch.

(b) Each disconnect switch.

(c) Each set of fixed metering voltage transformer fuses.

(d) Each set of high voltage power fuses.

Such barriers shall extend from the base of the insulator supports to a point 50mm beyond the fuse ferrules or the open blades of switches and 50mm beyond the terminal pads.

9.8.2 Horizontal Barriers

Where cable terminations and loadbreak switches (or isolating switches) or power fuses and loadbreak switches (or isolating switches) are installed in the same compartment in accordance with 9.3.4(a) and 9.3.4(c), barriers shall be installed so as to prevent anyone working in the lower section of the compartment from reaching up and coming into hazardous proximity with live conductors. (This permits work to be done in the cable termination compartment or power fuses to be changed without de-energizing the whole sub-station).

9.8.3. Type of Barriers

The barriers must be white, flame retardant insulating material meeting NEMA requirements for grade GPO-3 and be a minimum 5mm thick.

9.9 Lightning Arresters

Lightning arresters are not required when substations are supplied from underground feeders. If the customer wishes to install lightning arresters, they shall be located on the loadside of the first protective devices. If the supply to the substation is from overhead system, Toronto Hydro shall install lightning arresters at the pole and the customer may install lightning arresters in the switchgear on the loadside of the incoming disconnect device. The mimic diagram shall indicate the presence of such devices in the switchgear.

9.10 Voltage Indicators

Voltage indicators shall be supplied and installed by the Customer in the incoming cable termination compartment between the cable termination and the first isolating device. Voltage indicators shall be approved by Toronto Hydro. The voltage indicators must be clearly visible through the viewing window. (Refer to 9.6).

Where the incoming cable terminates in a rear compartment and the isolating device is located in the front compartment, two sets of voltage indicators shall be installed, one in each compartment. A viewing window for each set of indicators shall be provided.

9.11 Circuit Breaker

Circuit breakers shall comply with the latest edition of ANSI Standard C37.04 to C37.18 inclusive and it shall conform to the ratings as shown in Table 1 in section 9.1.

A legible warning sign stating "Contact Toronto Hydro for permission to operate" shall be posted next to the operating button/handle of the incoming/tie circuit breakers.

9.12 Control Power Supply

The recommended range of voltage for control apparatus is shown in Table 2 below:

Type of Control	Voltage
Nominal	125 V dc
Closing Range	90-140 V dc
Tripping Range	70-140 V dc

Table 2. Recommended Control Voltage.

(a) Control power supplies for protective equipment such as circuit breakers and relays must attain a high degree of reliability. Where batteries are used to supply protective equipment, a suitable battery monitor must be provided to give an alarm should the battery voltage or state of change fall below a safe level. Such monitoring device shall be connected to the load side of the battery circuit breaker or isolating switch.

(b) The control power supply to the protective relays must not be fused.

(c) A test button shall be provided to test all indicating lamps.

9.13 Power Fuses

9.13.1 Minimum Rating
Power fuses shall comply with the ratings specified in Table 1 in section 9.1.

9.13.2 Gas Expelling Type
When the power fuses are of a type which expel gases during the interruption of short circuit currents, the construction of the enclosure shall follow the fuse manufacturer's recommendation with regards to the following:

(a) Clearances between exhaust parts and other metallic parts.

(b) Mechanical design to withstand internal pressures and shock waves.

9.14 Loadbreak Switches

9.14.1 Minimum Ratings
Loadbreak Switches shall comply with the latest CSA Standard C22.2 No. 193 and shall conform to ratings specified in Table 1 in section 9.1.

9.14.2 Type of Switch
Each switch shall be 3 pole, group operated by a handle mounted external to the compartment which contains the switch. This handle shall be so arranged that the operator may open or close the switch from a position not immediately in front of the switch contacts. The handle shall be equipped with a dual locking

device for locking the switch in either open or closed position, suitable for use with a standard Toronto Hydro padlock with 8mm shackle (refer to 6.7 for dual lock requirements). Both open and closed positions of the handle shall be clearly labeled. The top of the handle in the closed position shall be no higher than 1.8 m above the floor level.

9.14.3 Operating Mechanism

The operating mechanism of all loadbreak switches shall be designed so that a mechanical failure of a component, linkage, chain, etc., shall not result in an electrical fault and meet the following requirements:

(a) Switches shall be constructed or mounted such that gravity shall not tend to close them.

(b) The maximum force on the handle to operate the switch is 16Kg.

(c) Where chains are used, a securely bolted full chain guard shall be provided.

9.14.4 Switch Contacts

The switch contacts shall be silver-plated or tin-plated. The clearance between the fixed and moving switch contacts in the open position shall conform to the requirements of the latest ANSI C37.32. The open/closed switch contacts shall be visible through the viewing window.

9.14.5 Operating Warning Sign

A legible warning sign stating “Contact Toronto Hydro for permission to operate” shall be posted next to the operating button/handle of the incoming/tie load break switches.

9.15 Isolating Switches

9.15.1 Location of Switches

An isolating switch shall be installed on the line side of an incoming feeder circuit breaker or motorized loadbreak switch to permit incoming feeder isolation and/or grounding.

9.15.2 Switch Requirement

Isolating switches shall be 3 pole, group operated and shall conform to the requirements stipulated in Section 9.14 except that isolating switches need not have a closing or interrupting rating.

9.15.3 Isolation for Vacuum or SF6 Type Circuit Breakers/Switches

Loadbreak switches shall be used for isolation purpose when vacuum or SF6 type circuit breakers/switches are used.

9.16 Electrical Clearances

9.16.1 Conductors

The phase to phase and phase to ground clearances of conductors and other current carrying parts shall be in accordance with the requirements of the latest CSA Standard C22.2 No. 31.

9.16.2 Connection Clearances

Where 13.8kV or 27.6 kV connections are made to any components supplied or installed by Toronto Hydro (e.g. current and voltage transformers, fuses, cable terminations), such connections shall be assumed to be bare and full CSA through air clearances shall be maintained.

9.17 Interlocks

Refer to sketches 1(a) through 1(h).

9.17.1 Incoming Circuit Breakers or Loadbreak Switches

Unless a split-bus arrangement is used [refer to sketch 1(h)] the two loadbreak switches or circuit breakers on the incoming lines shall be interlocked to ensure that not more than one switch or circuit breaker is in the closed position at any time. Provision shall be made, however, so that Toronto Hydro personnel, by the use of an additional key, may close both switches or circuit breakers simultaneously and thus permit the load to be transferred from one incoming feeder to the other without interruption to the service. [Refer to sketches 1(d) to 1(g)].

9.17.2 Incoming Isolating Switch

Isolating switch located on the line side of the incoming circuit breaker shall be interlocked to ensure that it may only be operated when the associated circuit breaker is open. [Refer to sketches 1(g) and 1(h)].

9.17.3 Access Door of Power Fuse Compartment

(a) In installations incorporating power fuses on outgoing circuits, an interlock shall be provided to prevent the access door of the outgoing circuit power fuse compartment from being opened unless the loadbreak switch preceding the power fuse is open, and to prevent the preceding switch from being closed until the power fuse compartment door has been locked closed. [Refer to sketches 1(b) to 1(e), 1(g) and 1(h)].

(b) In installations incorporating power fuses as the overcurrent protection for the customer service, interlock shall be provided to prevent the access door of the customer service power fuse compartment from being opened unless the adjacent loadbreak switches (or circuit breakers) on both the line side and load side of the customer service power fuse are open, and to prevent these switches (or circuit breakers) from being closed until the customer service power fuse compartment door has been locked closed. [Refer to sketches 1(c), 1(e) and 1(f)].

9.17.4 Loadbreak Switch on Outgoing Circuit

Where loadbreak switch and power fuse are provided in each of the outgoing circuits, the outgoing circuit power fuse compartment door shall be interlocked with the switch [refer to sketches 1(b), 1(c), 1(d), 1(e), 1(g) and 1(h)]. In installations incorporating customer service power fuse, the customer service power fuse compartment door shall be interlocked with the switch. [Refer to sketches 1(c), 1(e), and 1(f)].

9.17.5 Circuit Breaker on Outgoing Circuit

Where circuit breaker is provided in each of the outgoing circuits, the customer service power fuse compartment door shall be interlocked with the downstream circuit breakers and the upstream customer service loadbreak switch. [Refer to sketch 1(f)].

9.17.6 Incoming Circuit Breaker and Isolating Switch

The interlock between the incoming circuit breaker and the associated isolating switch must be designed such that the breaker must be locked in the open position before the key can be released to operate the isolating switch. Note, this does not preclude releasing the key when the breaker is in the test or disconnect position. [Refer to sketch 1(g)].

9.17.7 Customer Service Loadbreak Switch

The compartment door for customer service power fuses shall be interlocked with the preceding switch [Refer to sketches 1(c), 1(e) and 1(f)].

9.17.8 Marking of Interlock Keys

Interlock keys should have the inscriptions “KIRK TYPE INTERLOCKS DO NOT DUPLICATE”. Kirk type interlock key should be procured from manufacturer of Security and Safety Equipment for safety and security reasons.

9.18 Grounding

9.18.1 Additional Grounding

In addition to grounding requirements as specified in the latest CSA Standard C22.2 No. 31, readily accessible ground connection shall be provided in each of the incoming line cable termination compartments and in the metering voltage transformer compartment.

9.18.2 Grounding Facilities

In order to comply with the Occupational Health and Safety Act, the following facilities for grounding the incoming feeder cable terminations must be provided:

(a) A standard grounding stirrup [refer to sketches 4(a) and 4(b)] must be installed on the ground bus in each incoming feeder termination compartment, approximately 0.3 meter inside the compartment door.

(b) A standard grounding stirrup [refer to sketches 4(a) and 4(b)] must be installed on each phase conductor in each incoming feeder termination compartment.

(c) Grounding using the 1-inch ball stud is also acceptable provided that the grounding cable is supplied and stored in a padlockable enclosure. This enclosure shall be supplied by the customer and shall be located adjacent to the switchgear. The minimum size of ground cable is 3/0 extra flex copper. Each incoming termination cell requires a set of grounding cables.

9.18.3 Cable Compartment

The ground connection in the cable termination compartments shall be positioned at an easily accessible location to accommodate Toronto Hydro ground clamp. When the incoming feeder termination is located at the upper compartment of the switchgear, a portable platform to facilitate the installation of grounds shall be provided. The platform shall be painted in gray and built according to the requirements shown in sketch 6.

9.18.4 Voltage Transformer Compartment

The ground connection in the voltage transformer compartment shall be provided with two 10/24 tapped holes to connect metering equipment ground leads.

9.18.5 Metallic Parts

Throughout the equipment all non-current carrying metallic parts shall be grounded.

9.18.6 Ground Grid Connections

The switchgear assembly ground bus shall be connected to the substation ground grid at two ends with minimum 2/0 copper ground wire.

9.19 Automatic Transfer between Normal and Standby Supply

9.19.1 Notification Requirements

If manual operation of the automatic transfer switch is required, Toronto Hydro must be advised in advance.

A typical automatic transfer scheme is shown on sketch 5.

9.19.2 Automatic Transfer Functional Requirements

(a) Under normal condition, the Normal breaker is closed, and the Standby breaker is open. Upon loss of the Normal supply, the Normal breaker (or loadbreak switch) shall open and the Standby breaker (or loadbreak switch) shall close. Automatic transfer shall be initiated only if the Standby supply is energized and lock out of the transfer scheme has not activated [part (c) below].

(b) After a successful transfer from Normal to Standby, the supply shall remain on the Standby feeder even after the normal feeder has been restored. Toronto Hydro shall manually switch the customer back to Normal feeder. Automatic transfer back to the Normal feeder shall take place only in the event of power loss of the Standby feeder, and provided the Normal feeder is energized. An adjustable time delay (0 to 10 seconds range) shall be provided, before a transfer is initiated. This shall apply to both the transfers from Normal to Standby and from Standby to Normal feeders.

(c) The equipment shall include suitable overcurrent protective devices to prevent a transfer in the event of a fault occurring on or downstream from the auto transfer circuit breakers (or loadbreak switches). In the event of an operation of these devices, the breaker must trip and the automatic transfer shall lock out, and shall remain locked-out until it is manually reset by Toronto Hydro. The lock-out device shall be key operated such that the key shall be retained by Toronto Hydro or, alternatively, a cover shall be placed over the device and locked with a Toronto Hydro padlock. The current transformers supplying the overcurrent devices shall be located on the line side of the circuit breakers (or loadbreak switches).

(d) An Auto-Manual selector switch shall be provided, and the manual control of individual supply circuit breakers (or loadbreak switches) shall only be possible with the selector switch in the Manual position.

(e) The control switches of each breaker (or loadbreak switch) shall be connected such that a customer may manually transfer from Normal to Standby and from Standby to Normal by first tripping the supply breaker (or loadbreak switch), and then closing the Standby (or Normal) breaker (or loadbreak switch). The paralleling of the incoming feeders by the customer is not permitted.

(f) A key operated “Toronto Hydro Interlock” switch, with one key only for Toronto Hydro use shall be provided. The key shall remain trapped in the lock when the interlock circuit is in the “By–Pass” position. This is to permit the paralleling of feeders by Toronto Hydro.

(g) Indication lights shall conform to the following Toronto Hydro standard:

RED	To indicate Breaker Closed
GREEN	To indicate Breaker Open
WHITE	A normally closed breaker has tripped and is now open.
BLUE	Potential Indication
YELLOW/AMBER	Lockout operation.

(h) Motorized loadbreak switches shall be equipped with a positive means, acceptable to Toronto Hydro, of making them inoperative when in the open position. This is to provide safe conditions when Toronto Hydro is making repairs or conducting tests.

(i) Voltage sensing transformers shall be arranged such that they can be easily disconnected from the feeder cables and locked in the disconnected position. This is to provide safe conditions when Toronto Hydro is making repairs or conducting tests on the feeder cables.

(j) Circuit breakers or loadbreak switches shall be equipped with an operation counter.

(k) Potential indication lights shall be provided for each ATS potential transformer associated with each incoming feeder.

9.20 Emergency Backup and Embedded Generation

9.20.1 Emergency Backup Generation

Where an emergency backup generator is installed by Customer to provide emergency power, paralleling of the emergency backup generator and Toronto Hydro power system is prohibited and it shall be positively precluded.

The following warning signs shall be provided to warn people of the presence of emergency backup generation:

(1) CAUTION
EMERGENCY BACKUP GENERATOR FEEDER
(2) CAUTION
EMERGENCY BACKUP GENERATOR

The first warning sign is to be posted at the generator feeder cell, and the second warning sign is to be posted at the door of the switchroom, one sign per door.

9.20.2 Embedded Generation

Embedded Generation shall comply with the requirements of “Toronto Hydro General Requirements for Parallel Generation” document in the Conditions of Service.

The following warning signs shall be provided to warn people of the presence of embedded generation:

(1) CAUTION
EMBEDDED GENERATOR FEEDER
(2) CAUTION
EMBEDDED GENERATOR

The first warning sign is to be posted at the generator feeder cell, and the second warning sign is to be posted at the door of the switchroom, one sign per door.

9.21 Pilot Wire Protection and Remote Tripping

9.21.1 Interstation Control Cables Cabinet (Refer to sketch 7)

Where pilot wire relay protection or remote circuit breaker tripping is required, a metal cabinet shall be provided and installed by the Customer for the termination of Toronto Hydro control cables (refer to sketch 7). The cabinet shall be mounted adjacent to the incoming primary cable duct face and shall not be smaller than 900 x 900 x 300 mm deep and shall be constructed as described in 10.4.2. (b) and (c). The Customer shall install a pair of #12 stranded wires between each pilot wire relay or remotely circuit provided exclusively for that purpose. The Customer shall install terminal blocks (10 points) in the cabinet as called for by Toronto Hydro.

9.21.2 Remote Tripping Relays (Refer to sketch 7)

If remote tripping is required, the customer shall provide 48V D.C. relays (with 2 normally open 15A contacts) mounted in a separate 300 x 300 x 150mm deep box. The box shall be attached to the pilot wire cabinet with 38mm bushing.

9.22 Test Blocks

Test blocks shall be installed in the current transformer secondary circuits on the relay panel for each set of protective relays to permit the disconnection of the protective relays and to short circuit the current transformer secondary circuit for test purposes.

Pilot wire relaying will require an isolating block to permit the disconnection of the relays outgoing communication lines for test purposes.

9.23 Annunciation – SF6 Low Pressure

(a) Each SF6 circuit breaker or any SF6 compartment within the electrical room shall have a gauge to monitor the low SF6 pressure installed within the circuit breaker or SF6 compartment.

(b) A warning light shall be provided on the control panel of each SF6 circuit breaker or any SF6 compartment to indicate “Low SF6 Gas Pressure”.

(c) A “Lamp Test” button shall be installed on the control panel of each individual circuit breaker or SF6 compartment for testing the individual warning light.

(d) A sign stating “Low SF6 Gas Pressure” shall be mounted above each warning light.

(e) The low pressure warning lights shall be simultaneously activated with the external light(s) as indicated in section 8.9.

9.24 Protective Relays

9.24.1 Relay Settings

Relays that are under Toronto Hydro's operating jurisdiction shall have provisions for Toronto Hydro seals to prevent unauthorized change of relay settings.

9.24.2 Current Transformer Secondary Wiring

The size of all current transformer secondary wiring shall be #10 AWG.

10. METERING REQUIREMENTS

For metering requirements, refer to the "Toronto Hydro Metering Requirements for 13.8kV & 27.6kV Customer-Owned Substations", (Section 6, Reference #7 of Conditions of Service).

11. ASSOCIATED PUBLICATIONS

The latest revisions of the Publication listed below shall apply. In case of conflict between the Publications below and T.H.E.S requirements, the latter will govern.

Canadian Standards Association (CSA):

C22.2 No. 31	Switchgear Assemblies
C22.2 No. 94	Special Purpose Enclosures 2, 3, 4 and 5
C22/2 No. 193	High Voltage Full-load Interrupter Switches
CAN 3-C13	Instrument Transformers

Electrical and Electronic Manufacturers Association of Canada (EEMAC):

G8-3.2	Metal Clad and Station-type Switchgear
G10-1	Revenue Metering Equipment in Switchgear Assemblies

Institute of Electrical and Electronic Engineers (IEEE):

Std 48	Test Procedures and Requirements for High Voltage ac Cable Terminations
Std 80	Outdoor Grounding Requirements

American National Standards Institute (ANSI):

C37.04 to C37.18	AC High Voltage Circuit Breakers (inclusive)
C37.20	Switchgear Assemblies: Including Metal-enclosed Bus
C37.85	Safety Requirements for X-Radiation Limits for AC high voltage power vacuum interrupters used in Power Switchgear.

National Electrical Manufacturers Association (NEMA)

SKETCHES

Sketch 1(a)	Typical Single Line Diagram Legend	
Sketch 1(b)	Incoming Circuit:	Loadbreak Switch
	One Outgoing Circuit:	Fuse
Sketch 1(c)	Incoming Circuit:	Loadbreak switch
	Outgoing Circuits:	Loadbreak Switches & Fuses
Sketch 1(d)	Incoming Circuits:	Loadbreak Switches
	One Outgoing Circuit:	Loadbreak Switch & Fuse
Sketch 1(e)	Incoming Circuits:	Loadbreak Switches
	Outgoing Circuits:	Loadbreak Switches & Fuses
Sketch 1(f)	Incoming Circuits:	Loadbreak Switches
	Outgoing Circuits:	Circuit Breakers
Sketch 1(g)	Incoming Circuits:	Circuit Breakers
	Outgoing Circuits:	Loadbreak Switches & Fuses
Sketch 1(h)	Incoming Circuits:	Circuit Breakers (Split-Bus)
	Outgoing Circuits:	Loadbreak Switches & Fuses
Sketch 1(i)	Incoming Circuits:	Pilot Wire Protected Circuit Breakers
	Outgoing Circuits:	Circuit Breakers
Sketch 2	Toronto Hydro Incoming Feeder Terminations	
Sketch 3	Pothead Mounting Plates and Gasket Standard (For Top Entry Termination)	
Sketch 4(a)	Grounding Stirrup Angled	
Sketch 4(b)	Grounding Stirrup Straight	
Sketch 5	Typical Automatic Load Transfer Schematic	
Sketch 6	Toronto Hydro Work Platform	
Sketch 7	Interstation Control Cable Cabinet for Pilot Wires	

CIRCUIT COMPONENTS

CABLE TERMINATION

LOADBREAK SWITCH

ISOLATING SWITCH

FUSE

CURRENT TRANSFORMER

POWER TRANSFORMER

WITHDRAWABLE CIRCUIT BREAKER

50/51 51N

RELAYS
(OVERCURRENT - PHASE & GROUND)

VOLTAGE TRANSFORMER

87PW

PILOT WIRE RELAY

VOLTAGE INDICATOR

INTERLOCKS

A — MECHANISM LOCK:
KEY RELEASED WHEN SWITCH LOCKED OPEN

B — MECHANISM LOCK:
KEY RELEASED WHEN BREAKER LOCKED OPEN

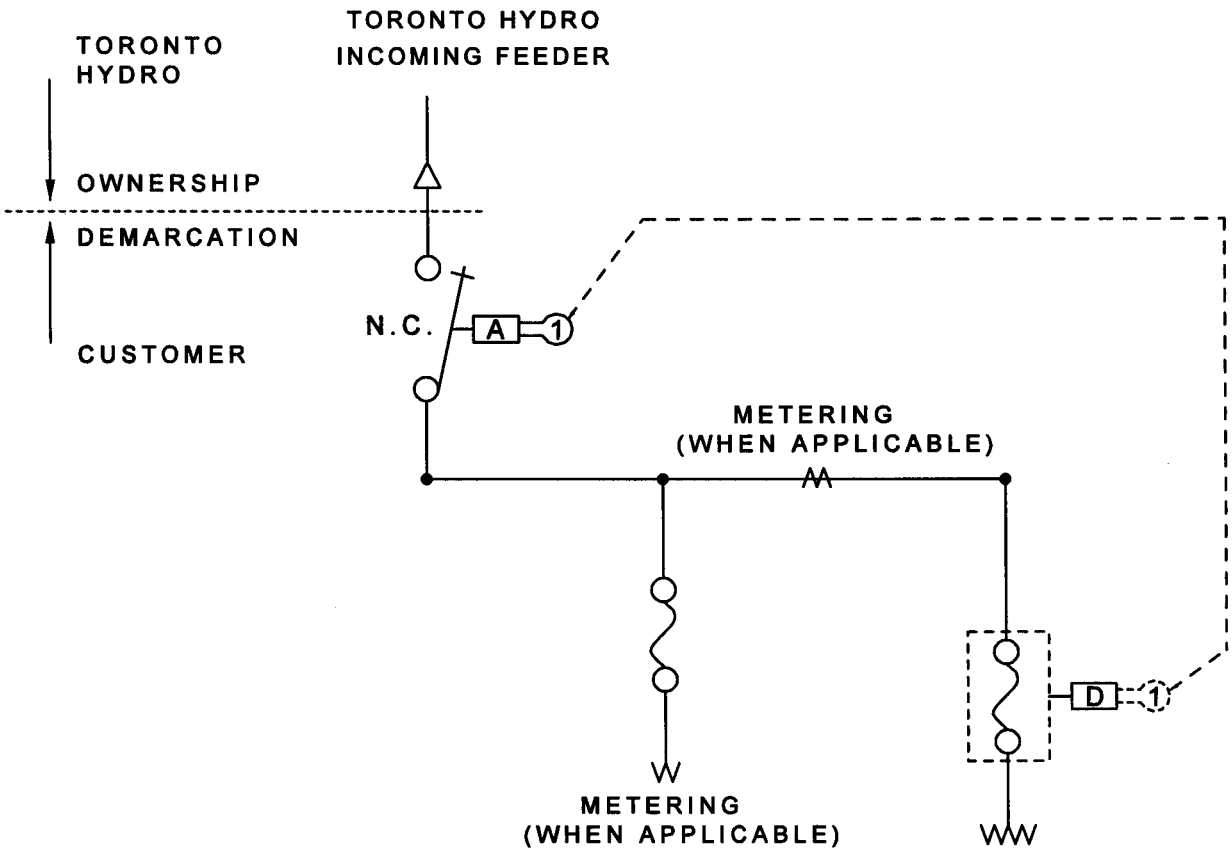
C — MECHANISM LOCK:
KEY RELEASED WHEN SWITCH IN EITHER
FULLY OPEN OR FULLY CLOSED POSITION

D — MECHANISM LOCK:
KEY RETAINED WHEN DOOR OPEN

2 — No.2 KEY SHOWN IN LOCK

2 — No.2 KEY REMOVED FROM LOCK

SKETCH 1(a)
TYPICAL SINGLE LINE DIAGRAM LEGEND

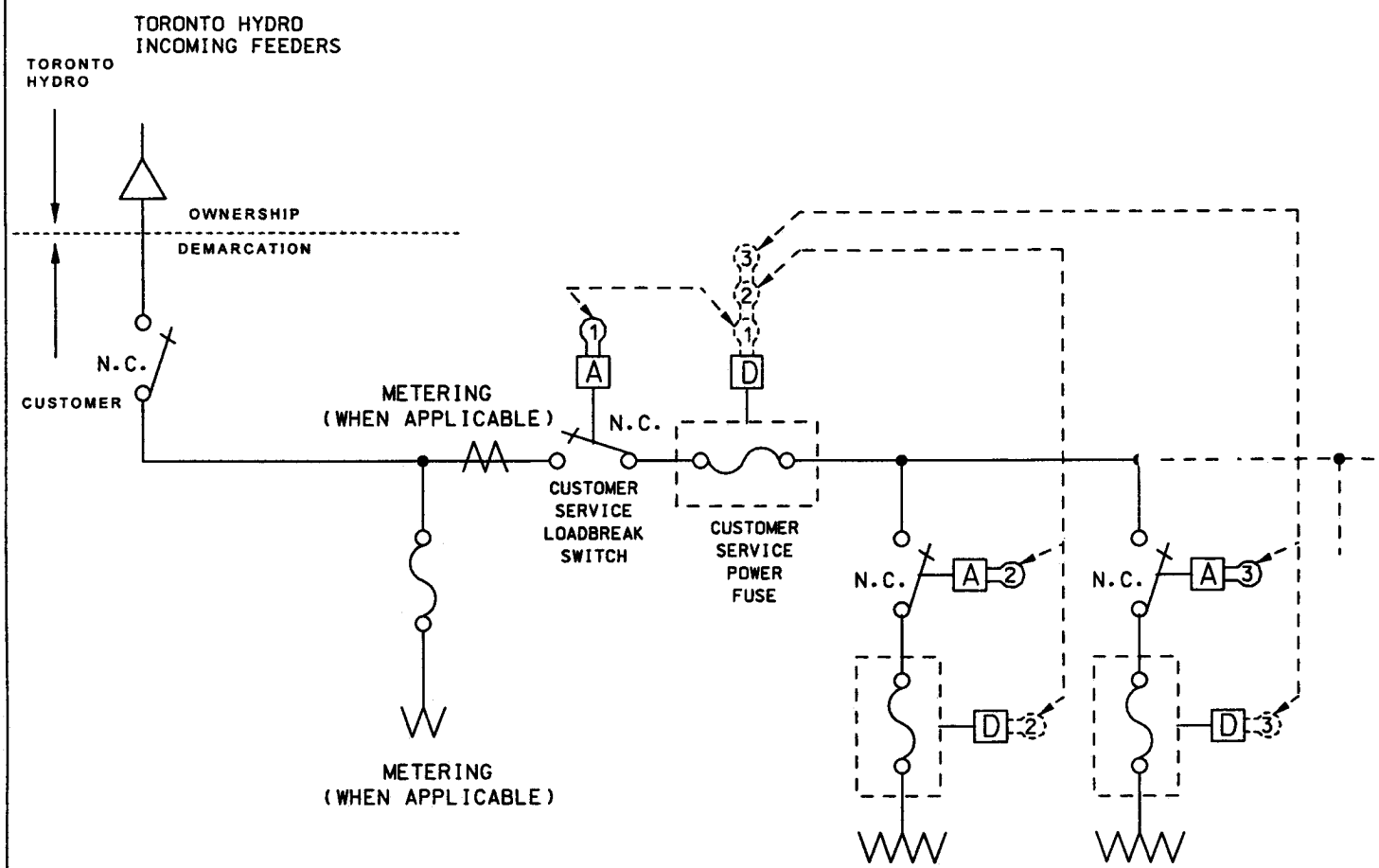


Interlock A1 to D1: Prevents The Fuse Compartment Door From Being Opened While The Preceding Line Switch Is Closed

Key trapped in switchgear: One No. 1 Key
Toronto Hydro Shall Retain: One No. 1 Key

Legend
see sketch 1(a)

SKETCH 1(b)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUIT: LOADBREAK SWITCH
ONE OUTGOING CIRCUIT: FUSE

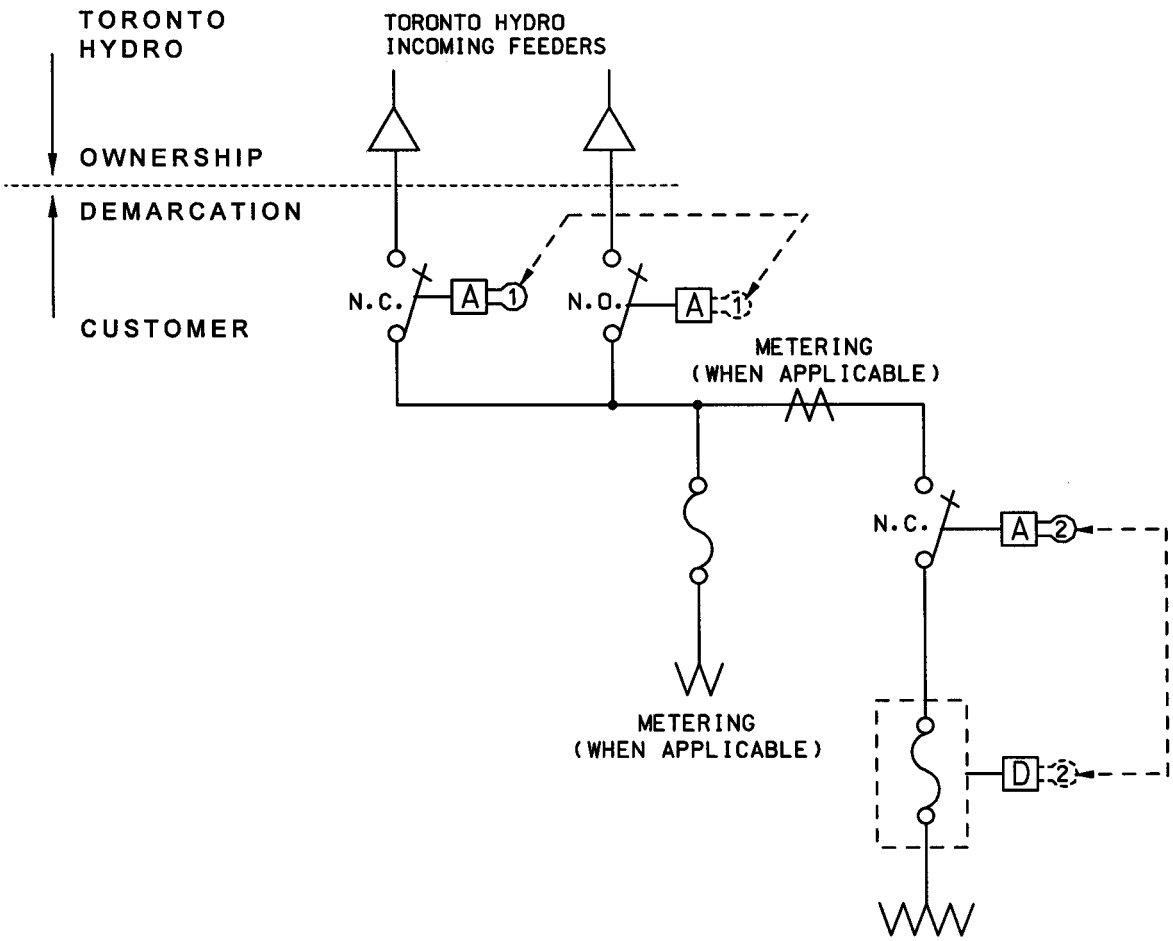


INTERLOCK A1 TO D1: PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE
& A2 TO D2: ADJACENT SWITCHES ARE CLOSED.
& A3 TO D3:

KEY TRAPPED IN SWITCHGEAR: ONE OF EACH KEYS: No.1, No.2, & No.3.
TORONTO HYDRO SHALL RETAIN: ONE No.1 KEY.

Legend
see sketch 1(a)

SKETCH 1(c)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUIT: LOADBREAK SWITCH
OUTGOING CIRCUITS: LOADBREAK SWITCHES & FUSES



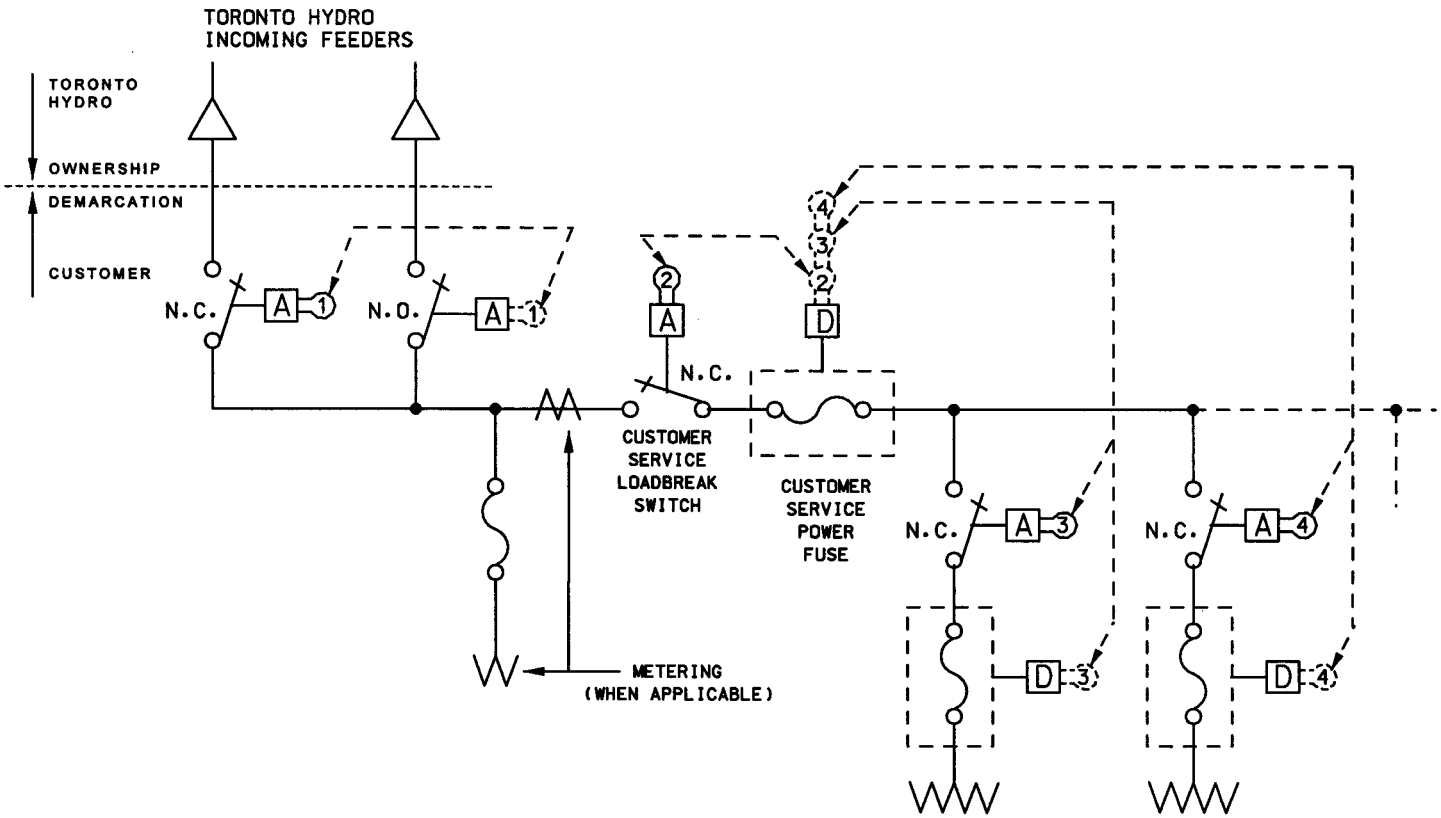
INTERLOCK A1 TO A1: PREVENTS THE INCOMING LINES FROM BEING PARALLELED BY THE CUSTOMER.

INTERLOCK A2 TO D2: PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE PRECEDING SWITCH IS CLOSED.

KEY TRAPPED IN SWITCHGEAR: ONE No.1, ONE No.2 KEY.
TORONTO HYDRO SHALL RETAIN: TWO No.1 KEYS.

Legend
see sketch 1(a)

SKETCH 1(d)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUITS: LOADBREAK SWITCHES
ONE OUTGOING CIRCUIT: LOADBREAK SWITCH AND FUSE



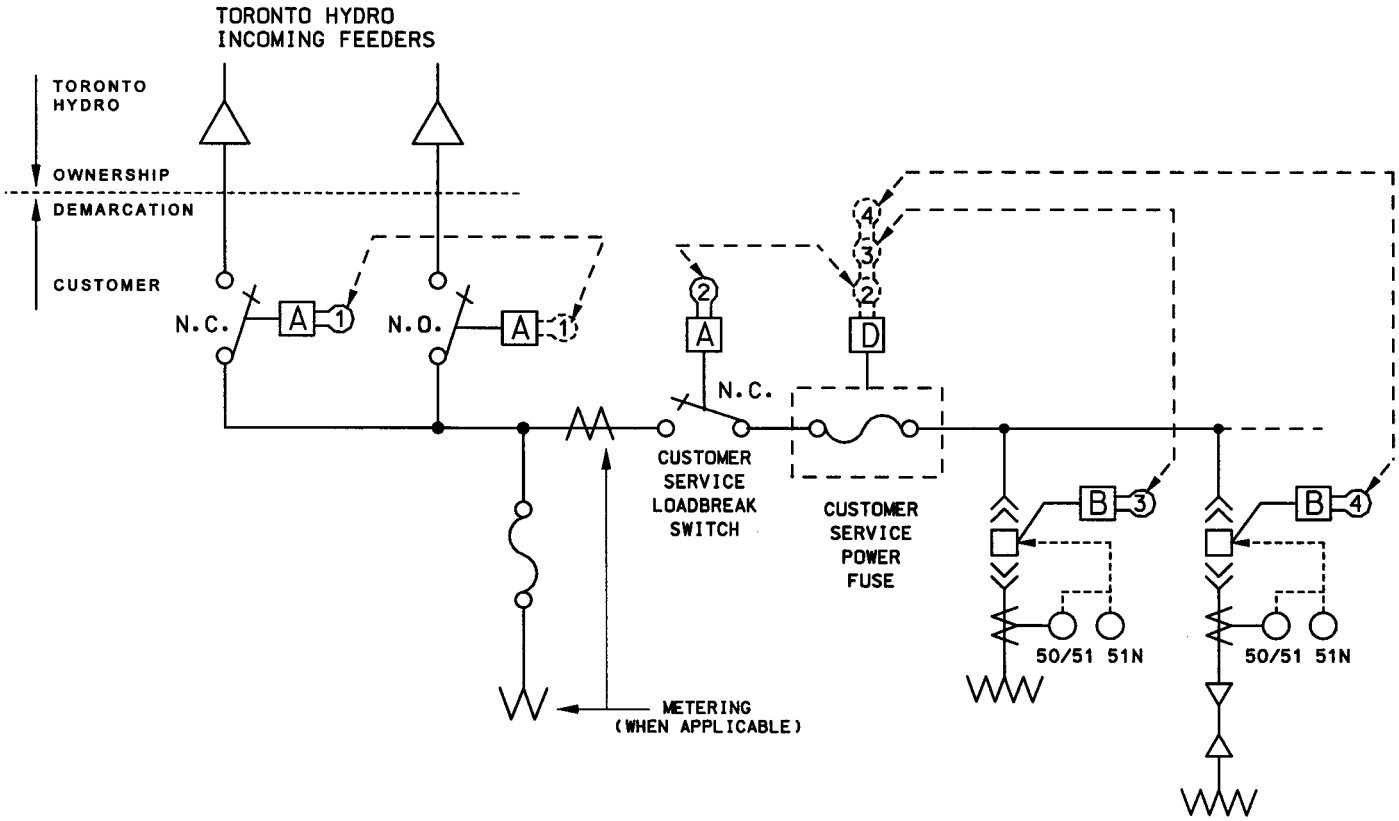
INTERLOCK A1 TO A1: PREVENTS THE INCOMING LINES FROM BEING PARALLELED BY THE CUSTOMER.

INTERLOCK A2 TO D2: PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE
& A3 TO D3: ADJACENT SWITCHES ARE CLOSED.
& A4 TO D4:

KEY TRAPPED IN SWITCHGEAR: ONE OF EACH KEYS: No.1, No.2, No.3 & No.4
TORONTO HYDRO SHALL RETAIN: TWO No.1 KEYS.

Legend
see sketch 1(a)

SKETCH 1(e)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUITS: LOADBREAK SWITCHES
OUTGOING CIRCUITS: LOADBREAK SWITCHES & FUSES



INTERLOCK A1 TO A1: PREVENTS THE INCOMING LINES FROM BEING PARALLELED BY THE CUSTOMER.

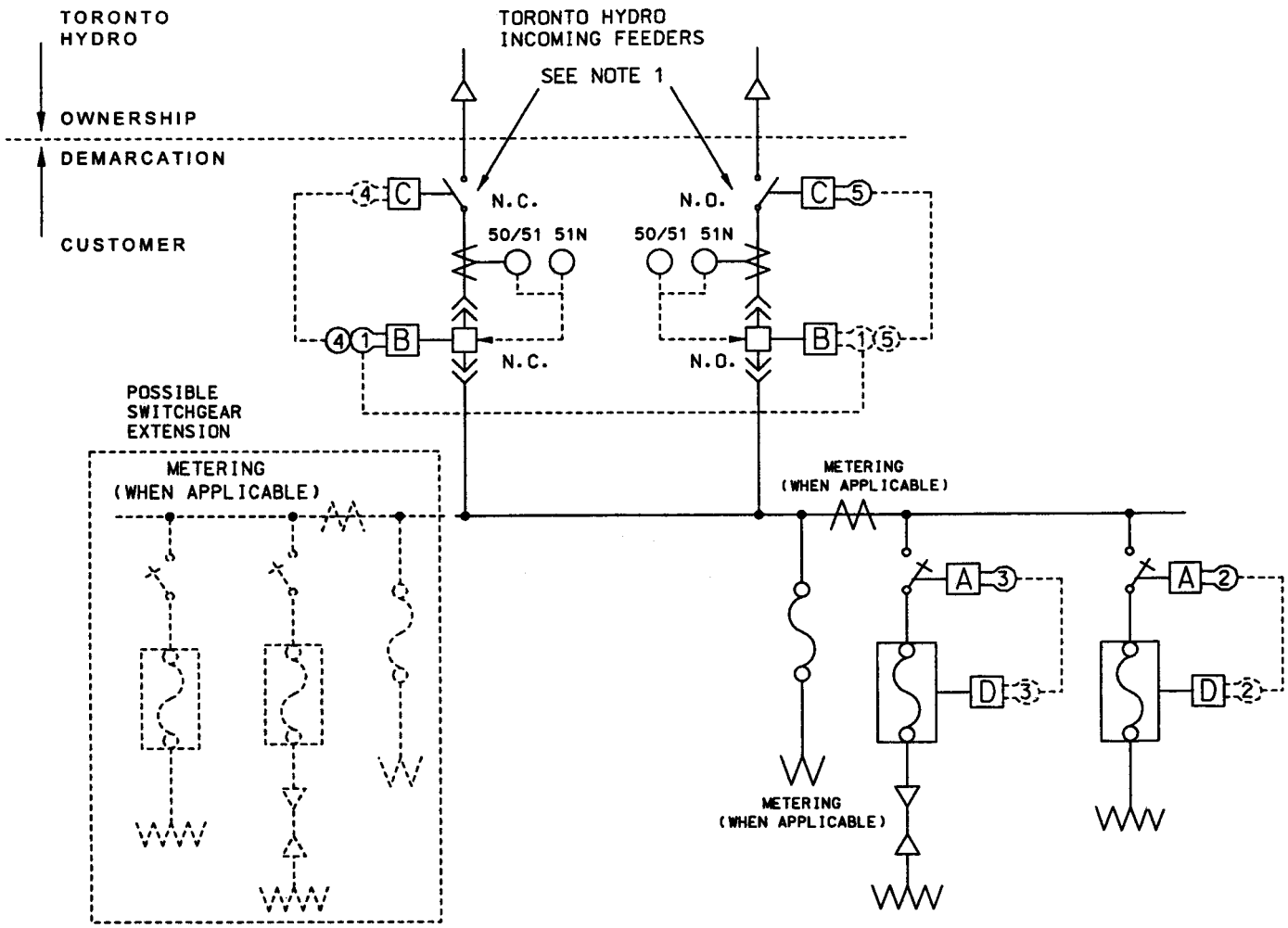
INTERLOCK A2 TO D2: PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE PRECEDING SWITCH IS CLOSED.

INTERLOCK B3 TO D3: PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE
B4 TO D4: BREAKERS ARE CLOSED.

KEY TRAPPED IN SWITCHGEAR: ONE OF EACH KEYS: No.1, No.2, No.3 & No.4
TORONTO HYDRO SHALL RETAIN: TWO No.1 KEYS.

Legend
see sketch 1(a)

SKETCH 1(f)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUITS: LOADBREAK SWITCHES
OUTGOING CIRCUITS: CIRCUIT BREAKERS



NOTES:

1. WITH VACUUM BREAKERS, UPSTREAM SWITCHES SHALL BE LOADBREAK SWITCHES. INTERLOCKS BETWEEN THE VACUUM BREAKER AND THE LOADBREAK SWITCH WILL NOT BE REQUIRED FOR THIS APPLICATION.

INTERLOCK B1 TO B1: PREVENTS THE INCOMING LINES FROM BEING PARALLELED BY THE CUSTOMER.

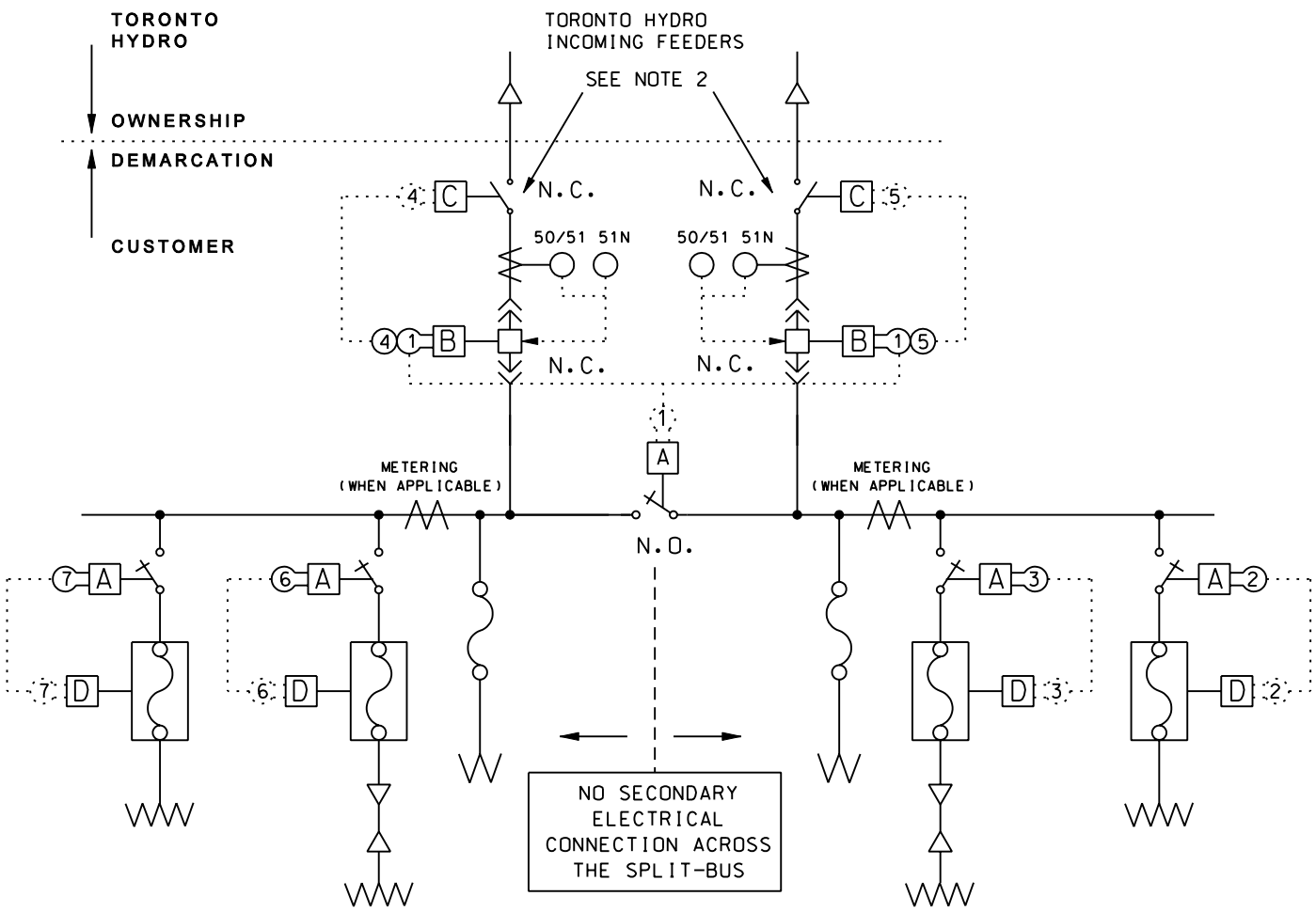
INTERLOCK B4 TO C4: & B5 TO C5 PREVENTS DISCONNECT SWITCHES FROM BEING OPERATED UNDER LOAD

INTERLOCK A2 TO D2: & A3 TO D3 PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE PRECEDING SWITCH IS CLOSED.

KEY TRAPPED IN SWITCHGEAR: ONE OF EACH: No.1, No.2, No.3, No.4, No.5 KEYS.
TORONTO HYDRO SHALL RETAIN: TWO No.1 KEYS, ONE OF EACH: No.4, No.5 KEY.

Legend
see sketch 1(a)

SKETCH 1(g)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUITS: CIRCUIT BREAKERS
OUTGOING CIRCUITS: LOADBREAK SWITCHES & FUSES



NOTES:

1. THE CUSTOMER SHALL NOT INSTALL ANY EQUIPMENT TO PERMIT ELECTRICAL CONNECTION BETWEEN TRANSFORMER SECONDARIES ACROSS THE SPLIT-BUS.

2. WITH VACUUM BREAKERS, UPSTREAM SWITCHES SHALL BE LOADBREAK SWITCHES. INTERLOCKS BETWEEN THE VACUUM BREAKER AND THE LOADBREAK SWITCH WILL NOT BE REQUIRED FOR THIS APPLICATION.

3. ELIGIBLE ONLY FOR CUSTOMERS AT 27.6kV.

INTERLOCK A1 TO B1: PERMITS A MAXIMUM OF TWO BREAKERS/TIE SWITCHES TO BE CLOSED.

INTERLOCK B4 TO C4: & B5 TO C5 — PREVENTS DISCONNECT SWITCHES FROM BEING OPERATED UNDER LOAD

INTERLOCK A2 TO D2: & A3 TO D3 & A6 TO D6 & A7 TO D7 — PREVENTS THE FUSE COMPARTMENT DOOR FROM BEING OPENED WHILE THE PRECEDING SWITCH IS CLOSED.

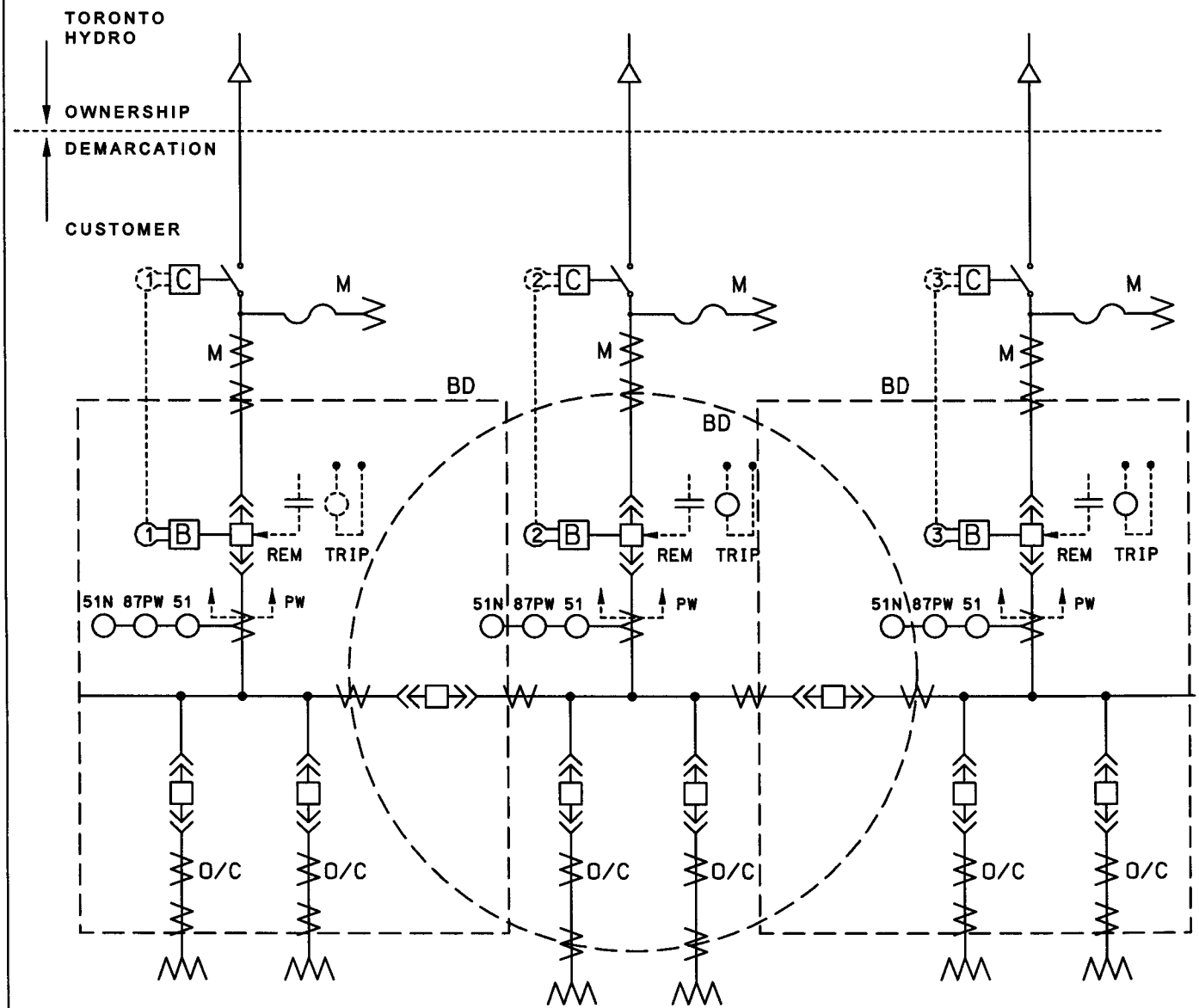
KEY TRAPPED IN SWITCHGEAR:
ONE OF THE No.2, No.3, No.4, No.5, No. 6, No. 7 KEYS AND TWO OF THE No. 1 KEY

TORONTO HYDRO SHALL RETAIN THREE OF THE No.1 KEYS, ONE OF EACH: No.4 & No.5 KEY.

Legend
see sketch 1(a)

SKETCH 1(h)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUITS: CIRCUIT BREAKERS (SPLIT-BUS)
OUTGOING CIRCUITS: LOADBREAK SWITCHES & FUSES

TORONTO HYDRO INCOMING FEEDERS



INTERLOCKS B1 TO C1 & B2 TO C2 & B3 TO C3 — PREVENTS DISCONNECT SWITCHES FROM BEING OPERATED UNDER LOAD.

REFER TO NOTES ON SKETCH 1(e) IF VACUUM BREAKERS OR VACUUM SWITCHES ARE USED.
KEYS TRAPPED IN SWITCHGEAR: ONE OF EACH: No.1, No.2, No.3 KEYS.
TORONTO HYDRO SHALL RETAIN: NONE OF KEYS.

BD: BUS DIFFERENTIAL PROTECTIVE ZONE
PW: PILOT WIRE PROTECTIVE ZONE
O/C: OVERCURRENT RELAY CURRENT TRANSFORMERS
M: TORONTO HYDRO METERING

REM TRIP: REMOTE TRIP RELAY(48V) WITH TWO NO CONTACTS

Legend
see sketch 1(a)

SKETCH 1(i)
TYPICAL SINGLE LINE DIAGRAM
INCOMING CIRCUITS: PILOT WIRE PROTECTED CIRCUIT BREAKERS
OUTGOING CIRCUITS: CIRCUIT BREAKERS

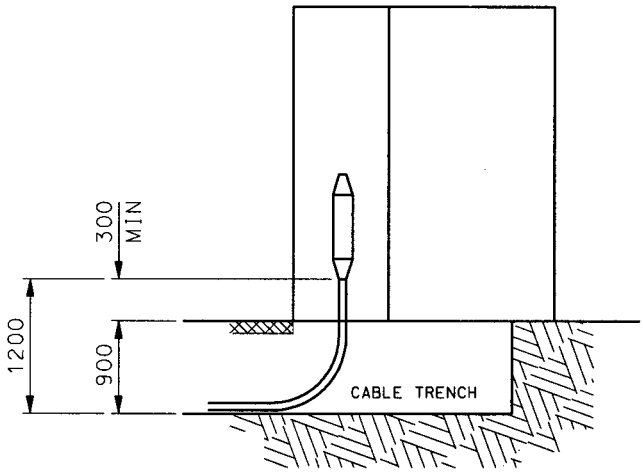


FIGURE 1

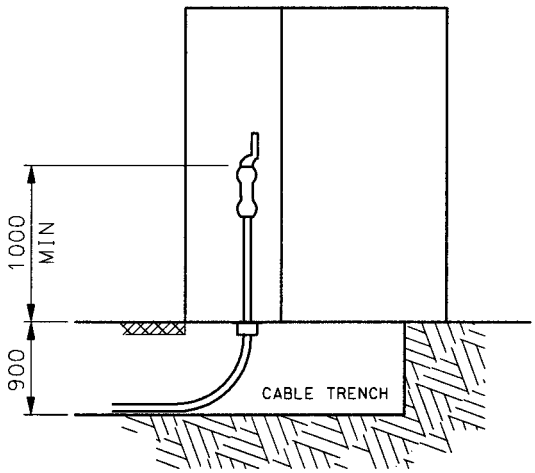


FIGURE 2

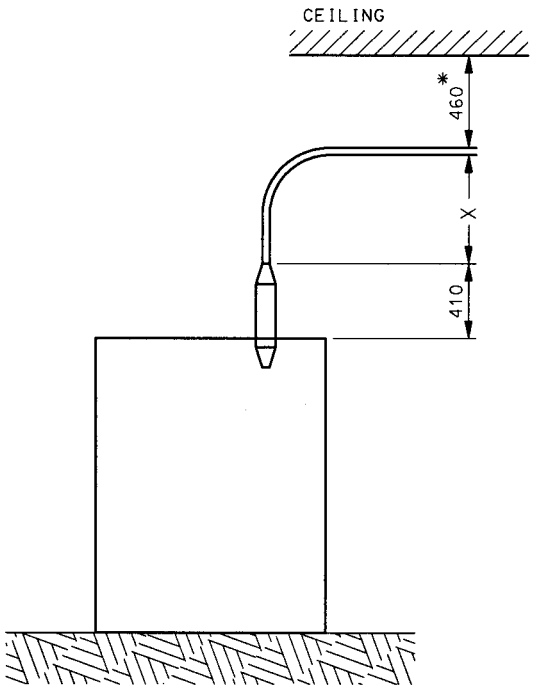


FIGURE 3

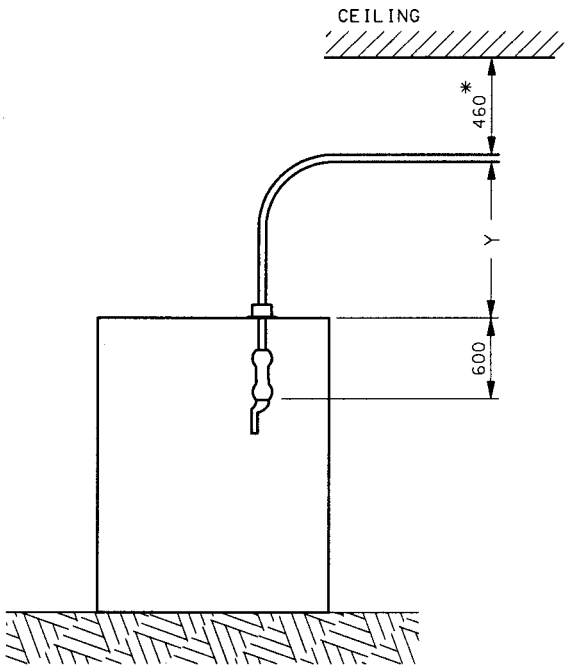


FIGURE 4

CABLE SIZE	X	Y	
	PILC (15kV)	XLPE (15kV)	XLPE (28kV)
#1/0			350
#2/0	610		
#3/0		300	
350 KCMIL	750		
500 KCMIL	830	400	
1000 KCMIL			680

ALL DIMENSIONS IN MILLIMETERS.
* DIMENSION SHOWN IS ALLOWANCE FOR RACKING CABLES TO CEILING.

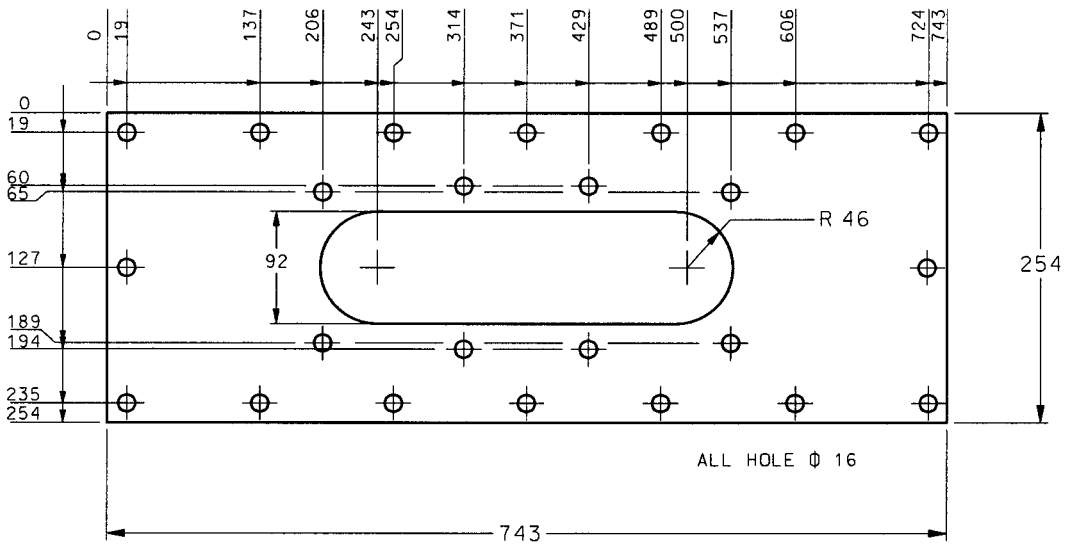
LEGEND

STRAIN RELIEF CONNECTOR

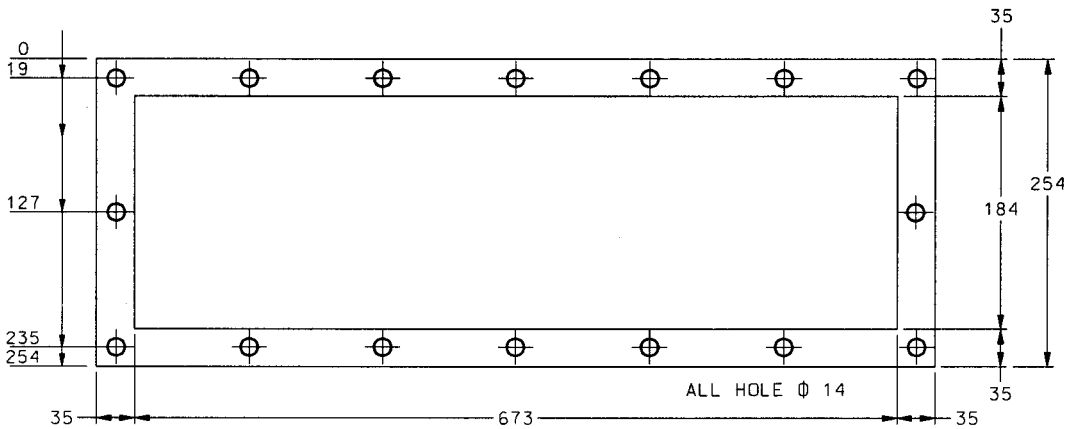
CLASS 1 CABLE TERMINATION (POTHEAD)

CLASS 1 CABLE TERMINATION (COLD SHRINK OR HEAT SHRINK KIT)

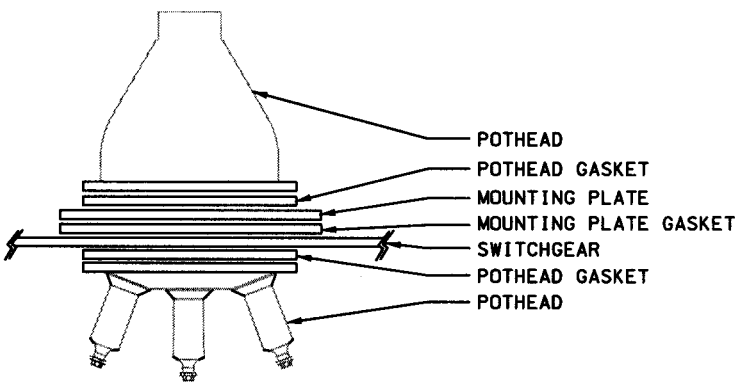
SKETCH 2
TORONTO HYDRO INCOMING FEEDER TERMINATIONS



MOUNTING PLATE (6mm THICK)



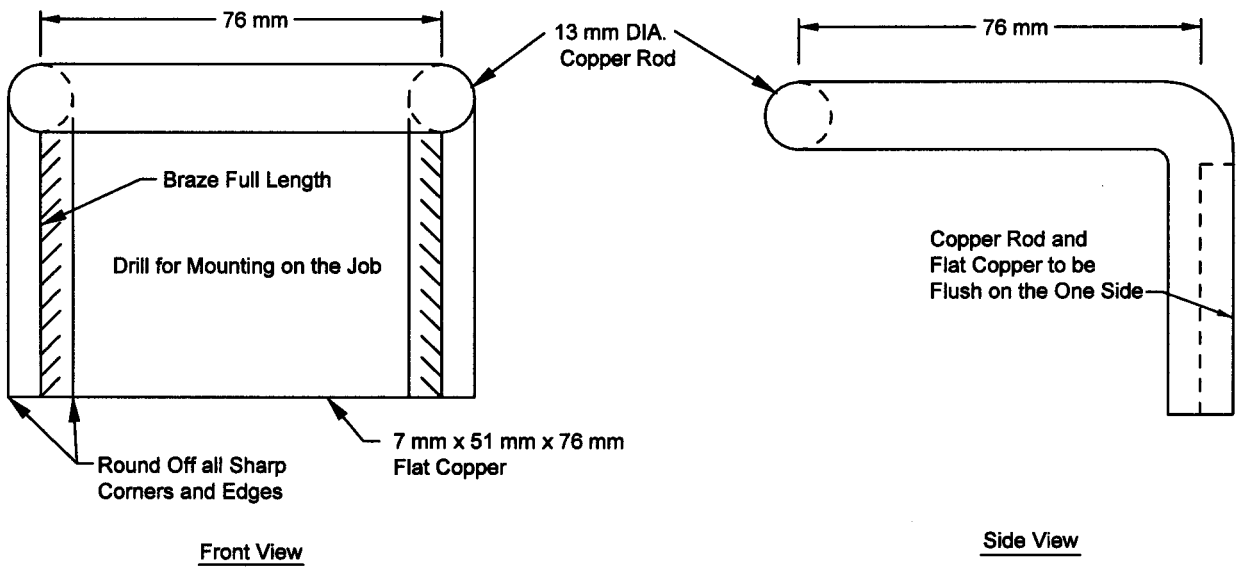
MOUNTING PLATE GASKET (3mm THICK)



DETAIL

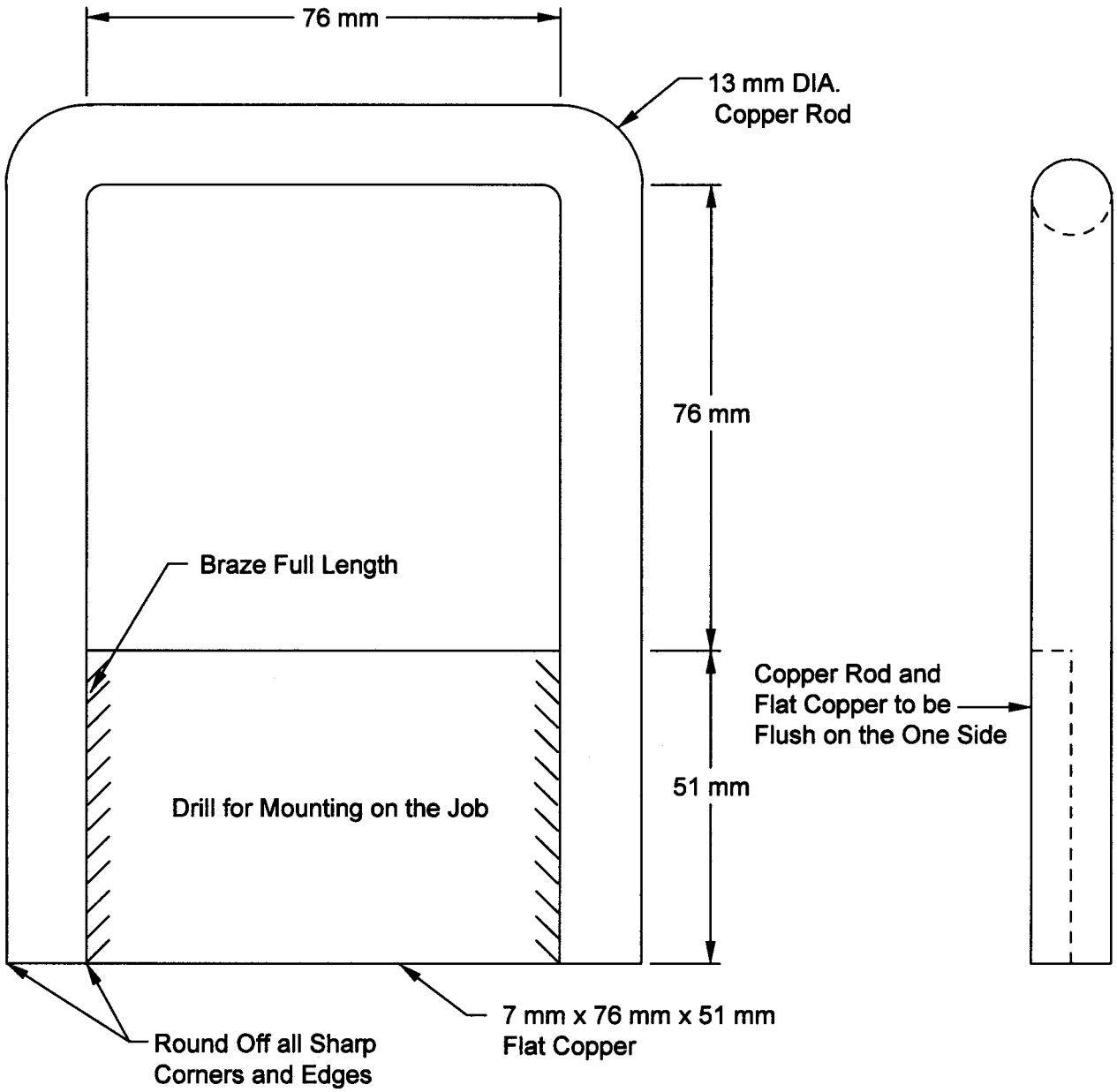
ALL DIMENSIONS IN MILLIMATERS

SKETCH 3
POTHEAD MOUNTING PLATES AND GASKET STANDARD
(FOR TOP ENTRY TERMINATION)



NOTE: SILVER PLATE COMPLETED GROUND STIRRUP ASSEMBLY

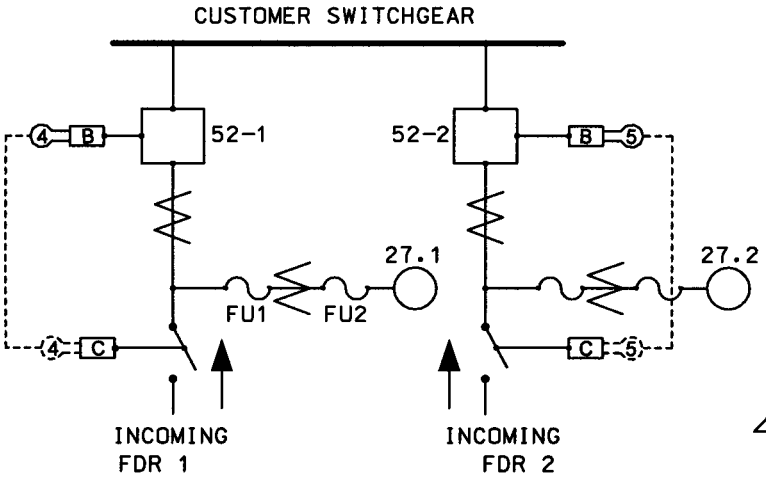
SKETCH 4(a)
Grounding Stirrup
Angled



NOTE: SILVER PLATE COMPLETED GROUND STIRRUP ASSEMBLY

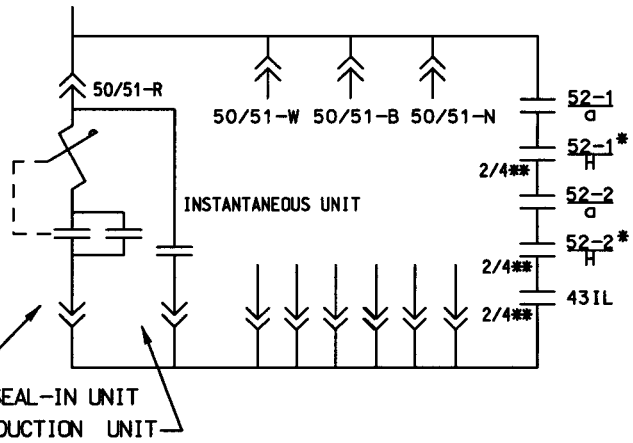
SKETCH 4(b)
Grounding Stirrup
Straight

A.C. SINGLE LINE



OVERCURRENT PROTECTION

INSERT A



INTERLOCK BY-PASS SWITCH (43IL)

THES INTERLOCK		
CONTACT	NORMAL	BY-PASS
1		X
2	X	
3		X
4	X	

*BREAKER CELL SWITCHES (52-1/H) AND (52-2/H)

	BREAKER POSITION	
CONTACT	TEST	OPERATING
1	X	
2		X
3	X	
4		X

SELECTOR SWITCH (43)

CONTACT	MANUAL	AUTO
	X	
		X
	X	
		X
	X	
		X
	X	
		X

1. ONE KEY REQUIRED FOR BOTH FEEDERS.
2. KEY KEPT IN A SEPARATE CABINET AND AVAILABLE TO TORONTO HYDRO ONLY FOR "BY-PASS" (PARRALLELING) OPERATION.
3. WITHOUT KEY - "NORMAL" (NO PARALLELING ALLOWED).

NOTES:

1. SCHEME MAY BE USED WITH MOTOR OPERATED LOADBREAK SWITCHES INSTEAD OF CIRCUIT BREAKERS.
2. TD-1 AND TD-2 TO HAVE GREATER TIME SETTING THAN 27-1T AND 27-2T.
3. OVERCURRENT RELAYS ARE REQUIRED WHICH WILL BE CAPABLE OF DETECTING ALL 13.8kV FAULTS ON THE CUSTOMER'S EQUIPMENT AND STOP THE TRANSFER OPERATION, PREVENTING THE TRANSFER OF FAULTY EQUIPMENT ON TO THE ALTERNATE SUPPLY FEEDER.

**4. CONTACT "2" IS FOR BREAKER 52-1 AND "4" IS FOR BREAKER 52-2.

*5. OMIT THESE CONTACTS IF LOADBREAK SWITCHES ARE USED IN LIEU OF CIRCUIT BREAKERS.

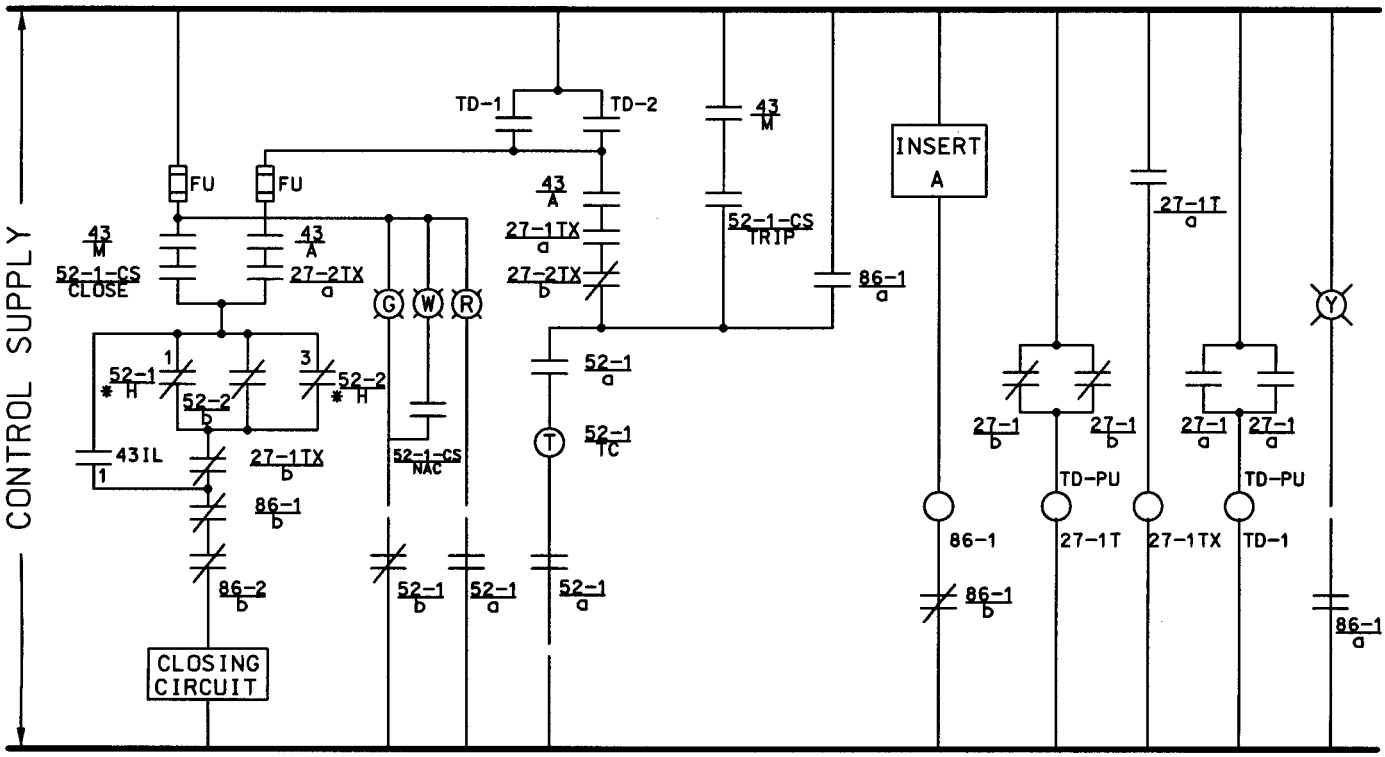
LEGEND:

52/TC	BREAKER TRIP COIL
52-1-CS	CONTROL SWITCH BRKR.-1
52-1	CIRCUIT BREAKER NO. 1
52-2	CIRCUIT BREAKER NO. 2
27-1,-2	VOLTAGE SENSING RELAYS
27-1T,-2T	0-10 SEC. TIME DELAY TO INITIATE TRANSFER
86-1,-2	LOCKOUT RELAYS, MANUAL/RESET
⌘	INDICATING LIGHTS
27-1TX,-2TX	AUXILIARY RELAYS
TD-1/TD-2	TIME DELAY RELAY (0-20 SEC. DELAY ON P/U) ELIMINATES RACING OF SERIES CONTACTS OF 27-1TX & 27-2TX UPON RETURN OF POWER AFTER A TOTAL INTERRUPTION

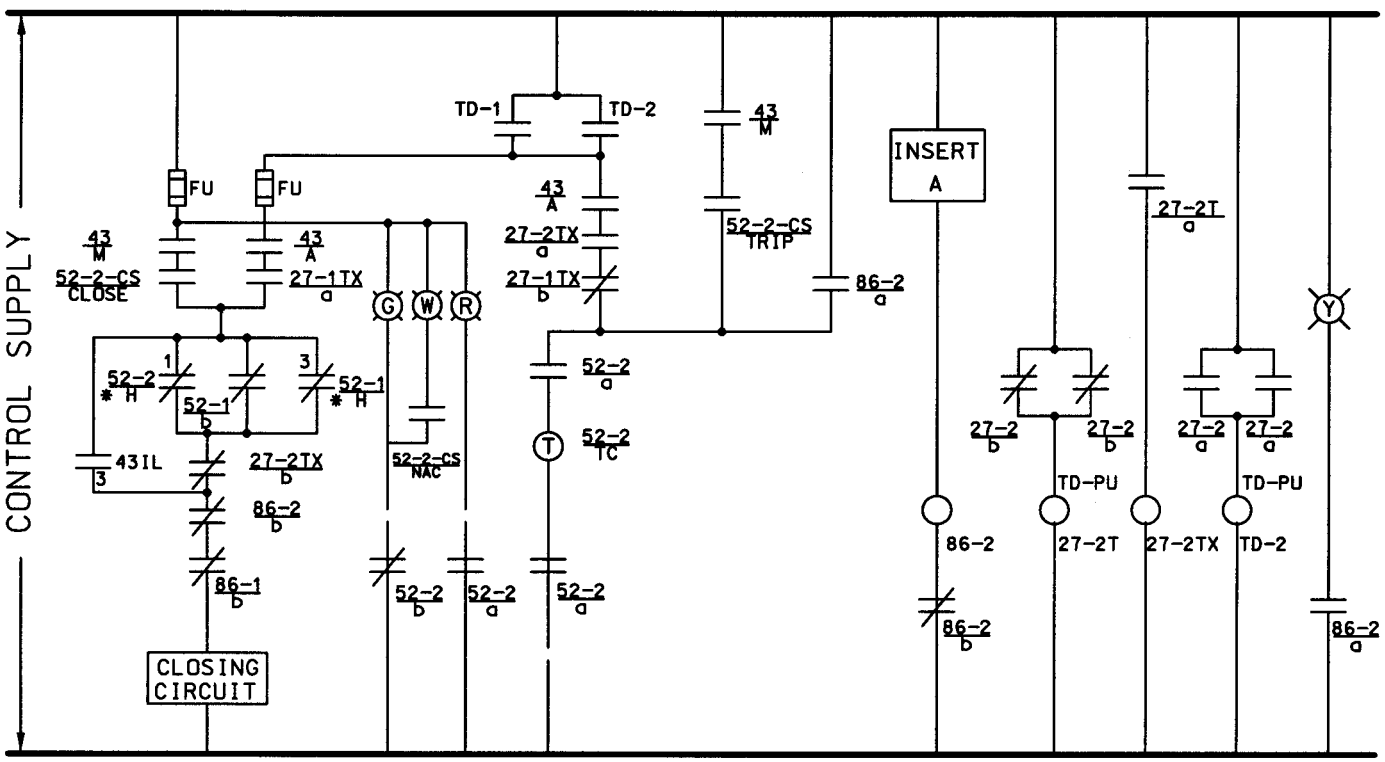
For additional Legends see sketch 1(a)

SKETCH 5 (PAGE 1 OF 2)

TYPICAL AUTOMATIC LOAD TRANSFER SCHEMATIC



BREAKER 1 (52-1)



BREAKER 2 (52-2)

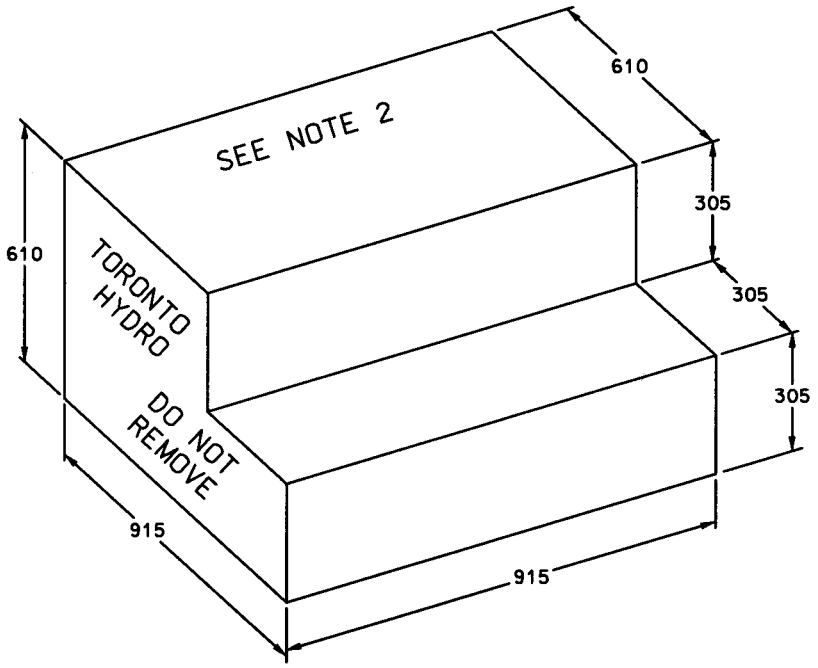
NAC: NORMALLY ALWAYS CLOSED

FOR A.C. SINGLE LINE, LEGEND AND NOTES: SEE SKETCH 5 (PAGE 1 of 2)

For additional Legends see sketch 1(a)

SKETCH 5 (PAGE 2 OF 2)

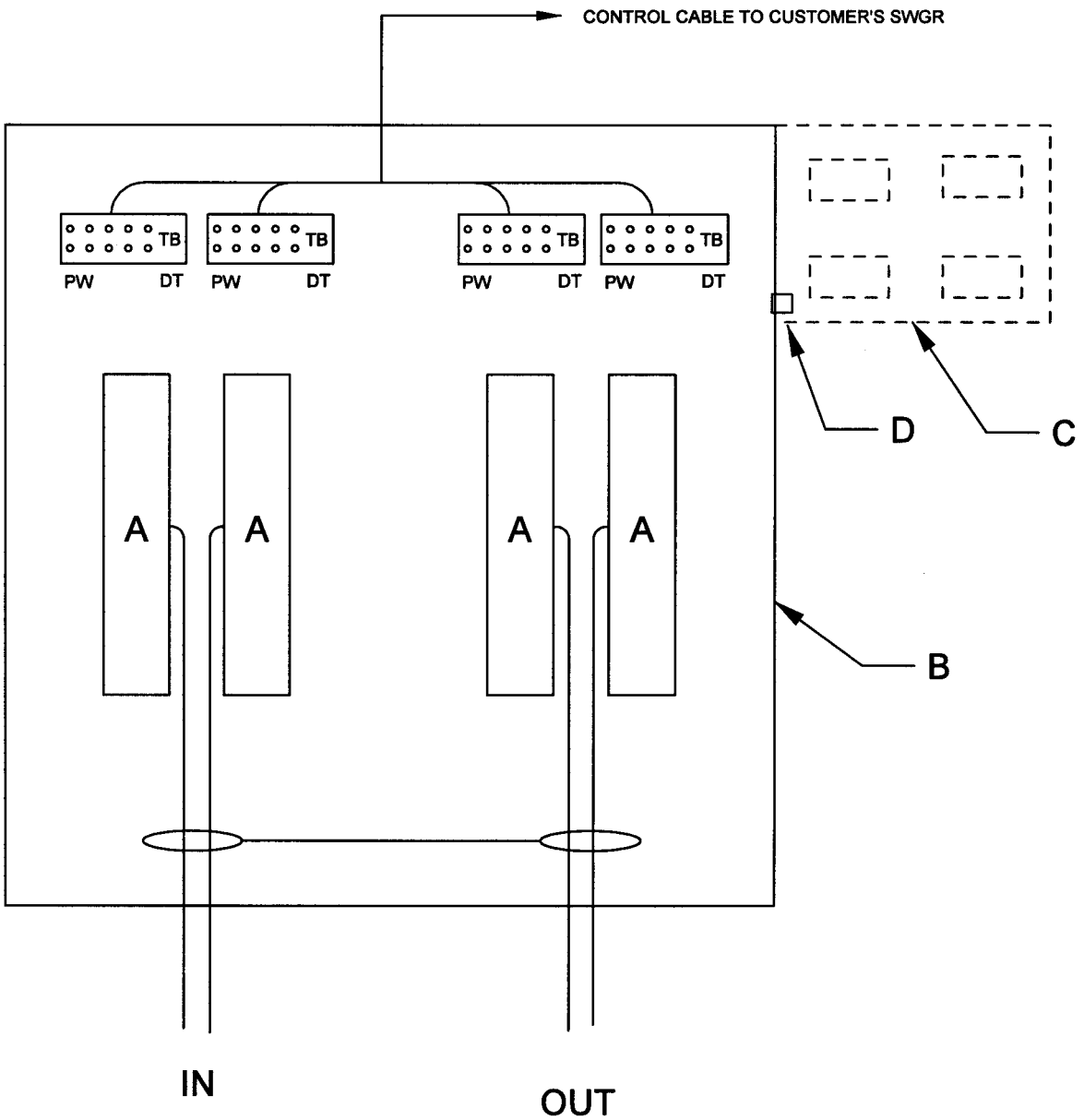
TYPICAL AUTOMATIC LOAD TRANSFER SCHEMATIC



NOTES:

1. ALL DIMENSIONS IN MILLIMETERS.
2. NON SLIP RUBBER MAT INSTALLED ON TOP OF PLATFORM.
3. 19mm PLYWOOD CONSTRUCTION.
4. FINISHED TO BE LEFT IN THE STATION. BOTH ENDS OF PLATFORM TO BE MARKED "TORONTO HYDRO - DO NOT REMOVE".

SKETCH 6
TORONTO HYDRO WORK PLATFORM



NOTES & LEGEND

THE 25PR. INTERSTATION CABLE SHALL BE LOOPED. THE LOOP MAY ENTER & EXIT AT EITHER THE TOP OR BOTTOM OF THE CABINET.

PW - PILOT WIRE
DT- DIRECT TRIP
A - TEST STRIP BY PHOENIX TYPE URTK/S-26 SINGLE CONDUCTOR POINTS
B - WEATHERPROOF CABINET 900 X 900 X 300mm.
TB - TERMINAL BLOCKS 10 POINTS
C - REMOTE TRIPPING RELAY BOX
300 X 300 X 150 mm HOUSING 48V RELAYS
EACH WITH 2 NO CONTACTS
D - 38mm NIPPLE WITH BUSHINGS AT BOTH ENDS

SKETCH 7
INTERSTATION CONTROL CABLE CABINET
FOR
PILOT WIRES

toronto hydro
electric system

SECTION 6 - REFERENCE #5

THESL REQUIREMENTS
FOR
CUSTOMER-OWNED STRUCTURES

PREPARED BY: _____
ENGINEER, STANDARDS & MATERIALS

REVIEWED BY: _____
SUPERVISOR, STANDARDS & MATERIALS

CERTIFICATE OF APPROVAL **THIS TECHNICAL SPECIFICATION MEETS THE SAFETY REQUIREMENTS OF SECTION 4 OF ONTARIO REGULATION 22/04**	
R Sironi, P. Eng **ROMANO SIRONI, P.Eng.** **MANAGER, POLICY & STANDARDS**	October 3, 2006 **DATE**

TABLE OF CONTENTS

Reference #	Title
31-6000	Design & Construction Requirements
31-6010	Transformer Vault Design Requirements
31-6020	On-Grade Transformer Vault
31-6030	Below Grade Transformer Vault
31-6040	Stair & Access Well Details for Below Grade Transformer Vault
31-6050	Louver Details For Vent Openings
31-6060	Bird Screen Details
31-6080	13.8kV Radial System for Below-Grade Vaults

CUSTOMER-OWNED STRUCTURES
DESIGN & CONSTRUCTION REQUIREMENTS

1.0 PURPOSE CLAUSE

1.1. The purpose of this document is to provide guidance to Toronto Hydro Customers and their agents in the preparation of plans and proposals for the construction of Structures (i.e. Customer-owned cable chamber, cable pull room, conduit/ ductbank, pad, splice box or vaults including submersible-vaults where Toronto Hydro equipment will be present).

1.2. Nothing contained in this document shall prejudice or supercede various other codes or regulations published in the current edition of Ontario Electrical Safety Code

1.3 It shall be the responsibility of the Customer to comply with Toronto Hydro requirements and all the other documents referred to in the Reference section of this document.

2.0 DEFINITIONS

2.1 Cable Chamber
A reinforced concrete underground structure where ducts are terminated for the purpose of making cable connections or accommodating a change in cable direction or level.

2.2 Cable Pull Room
An enclosed structure with a walk-in entrance where ducts are terminated for the purpose of making cable connections or accommodating a change in cable direction or level.

2.3 Conduit
A cable duct or grouping of ducts runs in parallel either direct buried or encased in concrete.

2.4 Customer
A person that has contracted for or intends to contract for connection to a building. This includes developers of residential or commercial subdivision.

2.5 Ductbank
Two or more conduits encased in concrete in accordance with Toronto Hydro Standard.

2.6 Easement
The right to use the real property of another for a specific purpose other than for general use and occupation of land.

2.7 Pad
A precast reinforced concrete foundation on which pad-mounted transformers, switchgears etc. are installed.

2.8 Splice Box
A fiberglass enclosure used for the making of multiple cable connection or terminating ducts.

2.9 Submersible Vault
A precast reinforced concrete structure used for the purpose of housing transformers in residential sub-divisions.

2.10 Structure
A general term to refer to one or more of the Customer-owned cable chamber, cable pull room, conduit/ ductbank, pad, splice box or vaults including submersible-vaults where Toronto Hydro equipment will be present.

2.11 Vault
A reinforced concrete structure used for the purpose of housing transformers, switchgear and other electrical distribution equipment.

3.0 REFERENCES

The Customer shall conform to the latest issue in effect at the date of construction of referenced codes, standards, regulations and by-laws.

3.1 APPLICABLE CODES

a. Canadian Electrical Code C22.1

b. National Building Code of Canada

c. National Fire Code of Canada

d. National Plumbing Code of Canada

e. Occupational Health & Safety Act and Regulation for Construction Project 1990 and Ontario Regulations 213/91

f. Ontario Building Code

g. Ontario Electrical Safety Code

h. Ontario Highway Bridge Design Code

3.2 REGULATIONS AND BY-LAWS

All local municipal and provincial regulations and by-laws shall apply.

3.3 OTHER REFERENCES

3.3.1 Toronto Hydro Publications:

a. Alternate Bid
b. Conditions of Service
c. Requirements for Design & Construction of Customer-Owned High Voltage Substation
d. Offer to Connect
e. Rule Book
f. Supply Agreement
g. Technical Specification for Civil Construction Work, CV-CON-01

3.3.2 City of Toronto Works and Emergency Services, Municipal Consent Document- Requirements for the installation of services within the City of Toronto Road Allowance.

3.4 TORONTO HYDRO STANDARDS

Standard #	Title
31-0100	Underground Clearances
31-1120	Concrete Encased & Direct Buried Ducts
31-1360	Identification of Hydro Ducts in Building Complexes
31-2130	Cable Chamber Structural Details
31-4030	Three Phase Precast Padmount 1830 x 1830 x 1220mm Deep
31-4080	Padmount Guard Posts Protection from Vehicular Traffic
31-5050	Vaults:- Minimum Clearances
31-6070	Cable Pull Room - Typical Installation of Low & High Voltage Cables
31-8210	Cable Pulling Loop for Poured & Precast Concrete Walls
31-8390	Transformer Vault Ladder
31-8410	Caulking of Removing Slabs
31-8470	Sleeve – Lifting for Removable Concrete Slab

4.0 TORONTO HYDRO REQUIREMENTS

3.5 ENGINEERING DRAWINGS

4.1.1 The unit of measurement shall be metric.

4.1.2 The Customer shall submit fully dimensioned scaled drawings in digital file (Microstation .dgn format) and two hard copies of the following drawings to Toronto Hydro for review for compliance to Toronto Hydro requirements:

4.1.2.1 Site Service Plan showing:

a. Location and grade levels of the building
b. Location of the electrical equipment and vault
c. Vehicle access route to the vault
d. Personnel access route to the vault
e. Grade levels at the vault
f. Location of incoming ductbank
g. References to the nearest intersecting streets
h. Property lines
i. Building lines with overhang
j. Adjacent utilities like gas, sewers, cables etc.
k. Any easements
l. Surface and sub-surface features including any obstructions.

4.1.2.2 Electrical Drawings showing:

a. Site Plan
b. Single line distribution drawings
c. Shop drawings of customer HV/LV service entrance, equipment, transformers, and protection co-ordination study.
d. Grounding details.
e. On-site commissioning of transformer and cable testing results for Customer-owned HV service entrance equipment.

4.1.2.3 Plan, elevation and section views of any proposed Structures.

4.1.2.4 Proposed drainage details from the proposed Structures according to latest Plumbing / Building codes.

4.1.3 All drawings must be reviewed and accepted by Toronto Hydro prior to commencement of construction.

4.1.4 If any drawings require revision, then the revised digital file and two hard copies shall be submitted to Toronto Hydro for further review and acceptance.

4.2 EASEMENT

4.2.1 Registered easements are required whenever Toronto Hydro's plant is to be located on private property to service a Customer other than the owner of the property where the plant is to be located.

4.2.2 When easement requirements have been identified for a particular project, the Customer shall be responsible for the following:

4.2.2.1 Preparation of a legal survey plan identifying the proposed easement for the underground hydro plant and also easements for access to the hydro plant where necessary. It may be necessary to identify the easements in three dimensions.

4.2.2.2 Prior to depositing the easement, the site survey plan should be reviewed and accepted by Toronto Hydro.

4.2.2.3 Preparation of a registrable easement in favour of Toronto Hydro comprising of:

a. Transfer Land Title Deed
b. Schedule 'A'
c. Land Transfer Tax Affidavit

The documents shall be prepared to the satisfaction of Toronto Hydro's solicitor.

4.2.2.4 The Customer shall deposit the easement. The cost of preparing a reference plan, easement, its registration and any other associated cost is to be borne by the Customer as part of the consideration for the provisions of electrical power supply.

4.3 STRUCTURES

4.3.1 The Structures shall be constructed in accordance with the Toronto Hydro Standard drawings. If it cannot be constructed to Toronto Hydro Standards, then detailed construction drawings shall be submitted to Toronto Hydro for review and acceptance. Construction must not commence until these drawings are accepted by Toronto Hydro.

4.3.2 When a Toronto Hydro Standard drawing is provided, the Customer shall be responsible for ensuring that a Registered Professional Engineer of Ontario does the structural design of the Structure to meet specific site conditions. The drawings shall be stamped by the Professional Engineer.

4.3.3 The Customer shall be responsible for ensuring that the Structure is constructed in accordance with the design criteria established by the Customer's Professional Engineer.

4.3.4 The Customer shall be responsible for the installation and maintenance of all the Structures.

4.3.5 During construction of a building, cranes shall not operate overhead in the vicinity of a Structure while Toronto Hydro personnel are working in or around the Structure.

4.3.6 If hoarding exists around a building under construction, a section of hoarding adjacent to the Structure shall be removed by the Customer on request to allow access for cranes, floats and other vehicles required to install Toronto Hydro equipment.

4.3.7 VAULTS

4.3.7.1 In addition to the requirements specified in this document, Transformer Vaults shall be designed in accordance with Standard 31-6010.

4.3.8 CABLE CHAMBERS

4.3.8.1 The cable chambers shall be designed in accordance with the Ontario Highway Bridge Design Code, Level-3 truck loading.

4.3.8.2 Cable Chambers shall be made of precast or cast-in-situ concrete.

4.3.8.1 Cable chambers shall have a drainage system built in accordance with the latest applicable codes and by-laws.

4.3.9 CABLE PULL ROOM

Cable pull rooms shall be built in accordance with Toronto Hydro Standards.

4.3.10 PADS

Pads shall be of precast concrete built in accordance with Toronto Hydro Standards.

4.3.11 SUBMERSIBLE VAULTS

Submersible vaults shall be of precast concrete built in accordance with Toronto Hydro Standards.

4.3.12 SPLICE BOX

Splice boxes shall be of fiberglass in accordance with Toronto Hydro Standards.

4.3.13 CONDUITS

4.3.13.1 The underground conduits shall be constructed in accordance with Toronto Hydro Standards.

4.3.13.2 The minimum depth of cover for conduits shall be 800mm. This depth is measured from the top of the final grade to the top of the concrete encasement of the ductbank.

4.3.13.3 Bends in conduits shall not be less than 900mm radius. Where sweeping bends are necessary, 5° (degree) couplings or sections of long sweep bends should be used.

4.3.13.4 Unless otherwise specified ducts to terminate in Structures with bell end fittings flush with encasement 150mm above finished floor or flush with the inside surface of the wall as applicable.

4.3.13.5 The conduits shall be graded away from the Customer's building and Structures to prevent water entering the building.

4.3.13.6 Customer shall design and install rebars where the ducts enter the Structure/building. The duct entry installation shall also be made watertight.

4.3.13.7 All spare ducts shall be roped and plugged.

4.3.13.8 It is the Customer's responsibility to build all the Structures in such a way that there is no water leakage into the Customers building and/or Structure. The Customer shall provide an undertaking to absolve Toronto Hydro from any damage to the building or equipment in the building due to water entering by means of conduit or excavation.

4.4 ACCESS REQUIREMENTS

4.4.1 Vehicle access routes to a Structure must be maintained 24-hours a day during the life of the Structure. Landscaping or other changes to an access route before or after installation of equipment shall not be made without prior approval of Toronto Hydro.

4.4.2 Access routes must be solely on the Customer's property containing the installation.

4.4.3 Customer shall maintain clean access wells for below-grade Structures at all times.

1 4.4.4 Hoarding or any other construction shall not be built over a Structure. If hoarding must encroach on below-grade Structure, it shall not block access to ladderway grids or personnel doors. A gate for access by Toronto Hydro personnel shall be provided in hoarding adjacent to the Structure. The gate shall be equipped with a hasp for a Toronto Hydro padlock.

4.4.5 Parking of vehicles is not permitted at any time on top of the below-grade Structures.

1 4.4.6 Landscaping of any kind is not permitted on top of below-grade Structures without the written approval from Toronto Hydro.

4.4.7 Access to a Structure located on Customer property shall be available to Toronto Hydro 24-hours daily.

4.4.8 The Customer shall provide Toronto Hydro with the appropriate access keys or magnetic cards to allow entry from the street to the Structure. The access keys or magnetic cards shall be placed in an accessible key box, which can be opened by Toronto Hydro's keys. Also, if a fence is erected around the Structure, it must be provided with Toronto Hydro padlock to allow Toronto Hydro personnel to gain access.

1 4.4.9 Any structure, tree, shrub, fence, landscaping or material shall not be built, planted or placed near the Structure that could obstruct the running of the distribution lines, endanger the equipment of Toronto Hydro or interfere with the proper and safe operations of Toronto Hydro's facilities or adversely affect compliance with any applicable legislation.

4.5 COMPLETION DATE

4.6.1 Vaults must be completed and accepted by Toronto Hydro eight (8) weeks before the requested service date to allow sufficient time for scheduling construction of associated conduit and for installation and connection of Toronto Hydro transformers and other equipment.

4.6.1 Equipping of the vault shall not commence until the vault construction is completed in full and accepted by Toronto Hydro and the vault can be locked without further entry being required by the Customer or Customer's agents.

4.6 INSPECTION BY TORONTO HYDRO

4.6.1 Toronto Hydro must be given 48- hours notice so that the Structures can be inspected at the following stages of construction:

a. before any concrete is poured and before ducts are covered
b. when formwork for the vault or cable chamber is completed
c. As soon as the construction is completed.

4.6.2 Toronto Hydro will inspect the Structures to ensure that the following items meet Toronto Hydro requirements:

a. Dimensions of Structures
b. Vault ventilation
c. Personnel access
d. Equipment access
e. Vault drainage
f. Location and elevation of primary and secondary conduits
g. Pulling eyes
h. Locations of ground rod, ground loops and bonding of all metallic hardware
i. Proper clearances of hatchways, grids, removable slabs and caulking (a trial lift must be arranged by the Customer to satisfy this requirement)
j. Adherence to Toronto Hydro safety requirements
k. Lighting and 120V supply receptacle

TRANSFORMER VAULT DESIGN REQUIREMENTS

1. GENERAL

a. This document is to be read in conjunction with the following Standards for Customer-Owned Structures:

Standard #	Title
31-6000	Design & Construction Requirements
31-6020	On-Grade Vaults
31-6030	Below-Grade Vaults
31-6040	Stair & Access Well Details
31-6050	Louver Details For Vent Openings
31-6060	Bird Screen Details
31-6080	13.8kV Radial System: Below-Grade Vaults

b. The vault sizes must comply with Toronto Hydro Standards and shall be suitable for oil-filled transformers.

c. Nothing contained in this document shall prejudice or supercede various other codes or regulations published in the current edition of Ontario Electrical Safety Code.

d. Based on the rating of the transformers, the vaults are classified as:

Type 1 – up to 2000kVA, Single Phase Banks
Type 2 – 2500 - 4000kVA, Three Phase Units

2. VAULT LOCATION

a. The vault location, size and personnel access route shall be discussed with Toronto Hydro before the preparation of the formal drawings. The proposed final location of the vault shall be approved by Toronto Hydro.

b. On-Grade Vault: Where the size of the Customer's electrical service warrants, the Customer shall, on the premises to be served, provide Toronto Hydro with a suitable vault at ground level.

c. Below-Grade Vault: If a suitable ground level location is not available, Toronto Hydro may accept a below-grade vault with conditions specified in this document, provided the vault will be at the floor immediately below the ground level.

d. The preferred location for a vault is on that part of the premises closest to Toronto Hydro's demarcation point of connection. Normally this will be adjacent to the street.

e. The effect of sound (low frequency vibrations) produced by the transformers should be considered in the selection of a vault location, especially for a building having living accommodations. Any sound dampening material/equipment that will be used shall be approved by the Customer's Professional Engineer and shall be acceptable to Toronto Hydro. The cost of all such work shall be borne by the Customer

f. A vault on Customer's property shall be in a location accessible at all times to Toronto Hydro personnel and vehicles required for maintenance and installation of transformers and other equipment.

g. A 6.0m wide paved driveway access is required to the vault.

h. The vault must be accessible for a large tractor-float combination. There shall be no obstruction or overhang above the vault for safe handling of transformers and other equipment.

i. A vault shall not be located close to a loading dock, storage areas or areas like restaurants, processing plants that have a potential of generating liquid waste.

j. A vault shall not be located directly under building egress/exits, in parking lots or beneath garage ramps.

k. Storage of any kind of materials or bins is not allowed on top of below-grade vaults at any time.

3. DESIGN & CONSTRUCTION

a. Vault shall be constructed in accordance with the latest editions of the applicable codes, standards and by-laws referred in Standard 31-6000.

b. Where vaults will be subject to vehicular loading, they shall be designed in accordance with the Ontario Highway Bridge Design Code, Level-3 truck loading.

c. The thickness of walls, floor and roof slabs of the vault shall not be less than 150mm.

d. The access route shall also be designed permanently for crane loadings. The design load for crane shall be to suit the Customer's equipment and location.

e. The grading around the below-grade vault shall be such that water will flow away from the vault roof.

f. No materials may be attached to any of the inside wall, ceiling or floor surfaces of the vault unless specified and/or installed by Toronto Hydro.

g. The inside walls, ceiling and floor to be painted with 2 coats acrylic latex white waterproof and non-flammable paint.

1 h. Pulling eyes to be installed on the wall or ceiling inside the cable entry room directly opposite to the duct entry, as specified by Toronto Hydro. Also, a pulling eye to be installed on the ceiling at door entrance for lifting of transformer into the vault. Pulling eye to be installed as per standard 31-8210.

i. Ductbank to be installed as per standard 31-1120. Preferred location of Ductbank entry are shown on the drawings. Ductbank to terminate in vault with bell end fittings flush with encasement 150mm above finished floor or flush with the inside surface of the wall as applicable.

4. GROUNDING

a. All metal parts to be grounded. Ground rods shall be taken to the last level of the building into the ground.

b. Four 19mm x 3.0m long galvanized steel ground rods are to be supplied and installed by the Customer. Connect a 2/0 stranded Cu. ground to the main service ground leaving a 3.0m long coil in the vault. Cable to be clipped at every 600mm.

c. Alternative grounding methods to be used only when ground rods cannot be placed within 150mm of inside vault wall and with prior approval of Toronto Hydro.

d. 48-hours notice required by Toronto Hydro to inspect grounding before floor is poured.

5. LIGHTING

a. Lighting system incandescent bulbs (4 x 200W in Type 1 vault and 6 x 200W in Type 2 vault) and power outlets to be supplied and installed in the vault by the owner

b. A 200W weatherproof incandescent bulb to be supplied and installed by the owner along with a suitable switch in the Access Well as per the Ontario Electrical Safety Code and connected to the building emergency lighting system where possible. This circuit to be supplied separately from the circuit feeding the vault.

c. For on-grade vault, 1-70W HPS amber light must be installed on the outside wall 300mm above center of doors and connected to building emergency and security lighting systems.

d. 2 x 200W incandescent bulbs along with a suitable switch are to be supplied and installed by the owner in the Air Intake Chamber as per the Ontario Electrical Safety Code.

e. A separate 120V/ 30A service is to be installed in the vault.

6. VENTILATION

a. The combined NET area of inlet and outlet openings for ventilation shall not be less than 19 sq. cm per kVA of maximum projected transformer capacity with a minimum of 930 sq. cm. The net area is based on the reduction in airflow due to louvers, bird screens and security bars.

b. Natural cross-ventilation is the best-suited way to ventilate the transformer vault. Inlet and outlet vents to be located in such a way as to provide maximum separation.

c. Mechanically assisted ventilation, if required, shall be approved by a Professional Engineer of Ontario hired by the Customer. A letter signed by the Professional Engineer that the ventilation meets the minimum requirements shall be submitted to Toronto Hydro prior to commencement of the vault construction.

d. Where mechanical ventilation is installed, the Customer shall routinely inspect and maintain the mechanical ventilation.

e. All ventilation openings shall be covered with double-louvers, bird screens and security bars, constructed of durable materials. They shall be installed in such a way that they are tamper proof.

f. The Customer shall be responsible to keep the ventilation openings clean in order to have adequate ventilation at all times

7. FIRE PROTECTION

a. Fire protection/damper shall be built in accordance with the latest applicable codes and by-laws.

b. The Customer shall own and maintain at all times the fire protection/dampening systems.

c. If smoke detectors are installed, they must be located in the ceiling above the door. No other location in the vault will be accepted. Control wires and/or conduit must not enter the vault except at the smoke detector. Smoke detectors shall meet applicable Building Code requirements and shall be connected to the building fire alarm system.

d. The transformer vault shall be totally enclosed by a fire separation of solid masonry or concrete having a fire rating of not less than 3 hours.

e. No sprinkler system is allowed inside the transformer vault.

2 f. All vault doors must be hollow metal fire doors having a fire separation rating of 3 hours. A free sliding pad, tamper proof pad bolt and Mortise strike to be installed. Pad bolt must be fastened to door and frame with tamper proof bolts. All metal parts including doors, hinges and pad bolts must be rust proofed. Astragal strips and Cadmium plated cane bolts (top & bottom of stationary door) are required on double door installations.

g. All door hinges must be stainless steel, i.e. Mortise type rust proof hinge with non-removable pin and ball bearings or equivalent.

h. An emergency door is required, location of which is to be approved by Toronto Hydro. This emergency door is in addition to the doors shown on Standards 31-6020 and 31-6030. Emergency door to have panic hardware installed to allow door to open from the inside. There shall be no method of opening an emergency door from the outside.

8. VAULT DRAINAGE

The transformers are oil-filled and therefore the Customer shall provide the drainage to the vault, where applicable, according to the latest codes and by-laws.

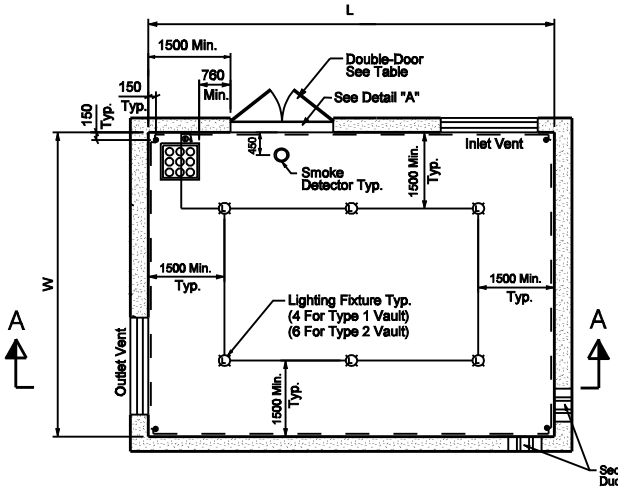
General Notes:

1). All dimensions are in millimeters unless noted otherwise.

2). This drawing shall be read in conjunction with Standards 31-6000 and 31-6010.

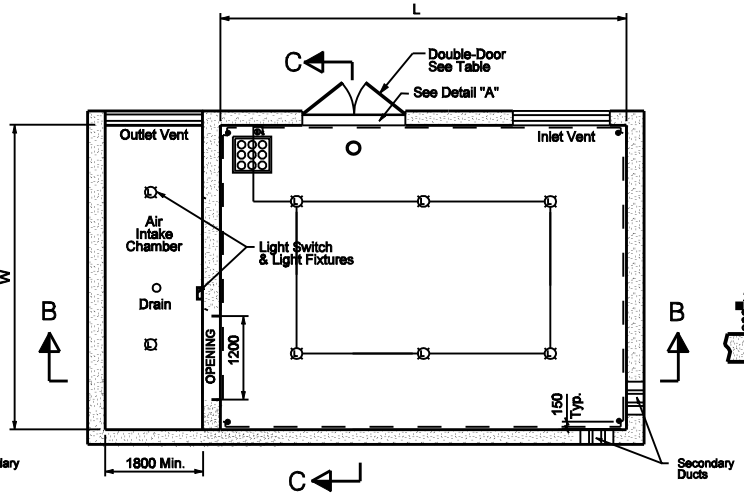
3). An emergency door is required, location of which is to be approved by Toronto Hydro. This door is in addition to those shown on the drawing.

3). Emergency door to have panic hardware installed to allow door to open from the inside. There shall be no method of opening an emergency door from the outside.



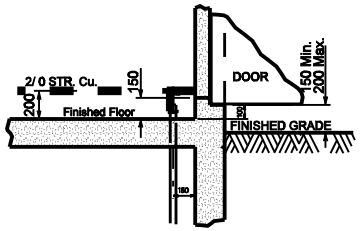
PLAN VIEW

NATURAL CROSS–VENTILATION



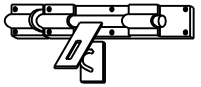
PLAN VIEW

ALTERNATIVE VENTILATION



DETAIL 'A'

DOOR & GROUNDING DETAIL



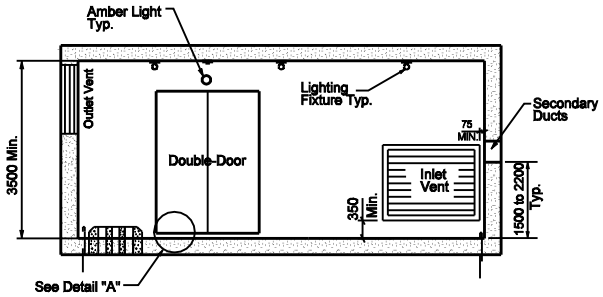
DETAIL 'B'

DOOR PAD BOLT

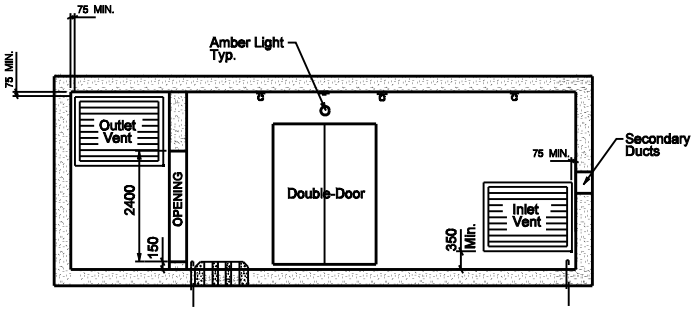
250mm BOLT

ON-GRADE VAULT SIZES				
TYPE	TX. RATING	L (m)	W (m)	DOUBLE-DOOR SIZE (mm)
1	up to 2000 kVA	8.0	6.0	1200 x 2400 High
2	2500 - 4000 kVA	10.0	8.0	1200 x 3000 High

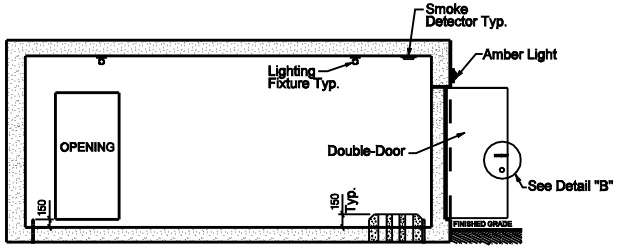
3



SECTION A-A



SECTION B-B



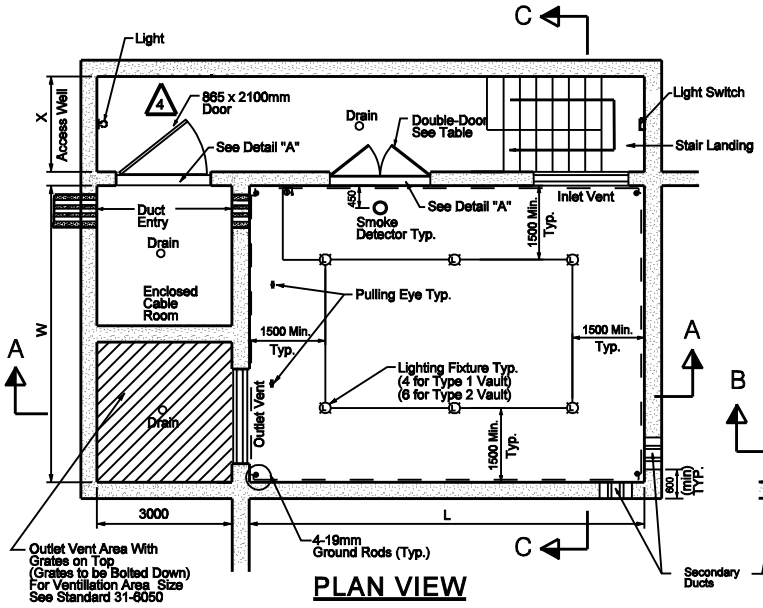
SECTION C-C

Reference	Standard
DESIGN AND CONSTRUCTION REQUIREMENTS	31–6000
TRANSFORMER VAULT DESIGN REQUIREMENTS	31–6010
LOUVER DETAILS FOR VENT OPENING	31–6050
BIRD SCREEN DETAILS	31–6060

DISTRIBUTION CONSTRUCTION STANDARD
Civil Construction

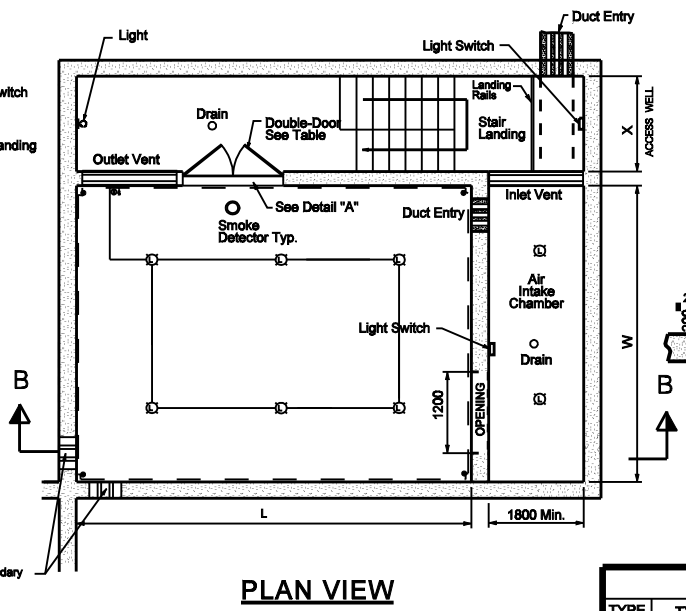
toronto hydro electric system

civil: G.D.	electrical: C.P.	CUSTOMER-OWNED STRUCTURES ON-GRADE TRANSFORMER VAULT				
original issue: 2003-11-27	scale: N.T.S.	rev. 1 G.D. C.P. 2004-03-31	rev. 2 G.D. C.P. 2004-07-30	rev. 3 G.D. C.P. 2004-11-30	31-6020	1/1



PLAN VIEW

NATURAL CROSS–VENTILATION



PLAN VIEW

ALTERNATIVE VENTILATION

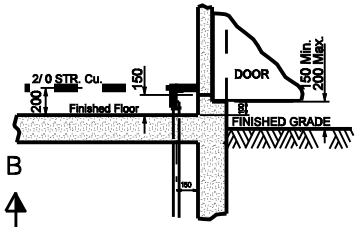
General Notes:

1). All dimensions are in millimeters unless noted otherwise.

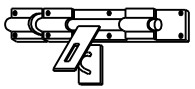
2). This drawing shall be read in conjunction with Standards 31-6000 and 31-6010.

3). An emergency door is required, location of which is to be approved by Toronto Hydro. This door is in addition to those shown on the drawing.

4). Emergency door to have panic hardware installed to allow door to open from the inside. There shall be no method of opening an emergency door from the outside.



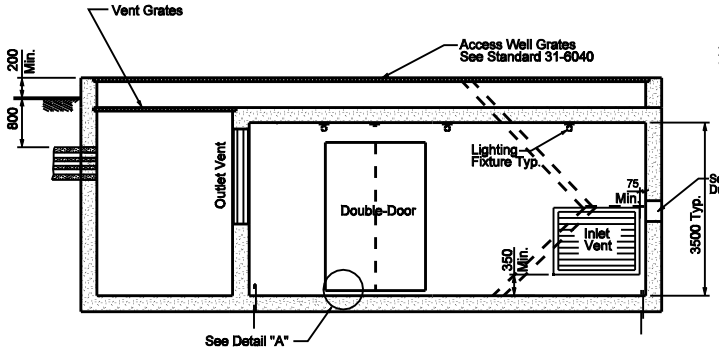
DETAIL 'A'
DOOR & GROUNDING DETAIL



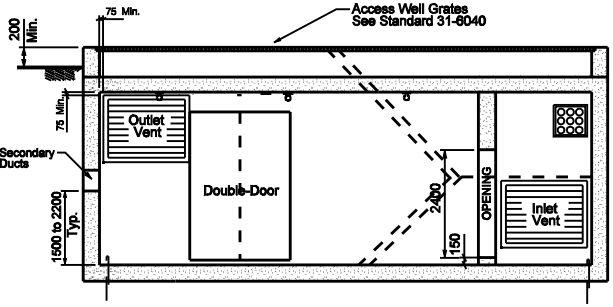
DETAIL 'B'
DOOR PAD BOLT

250mm BOLT

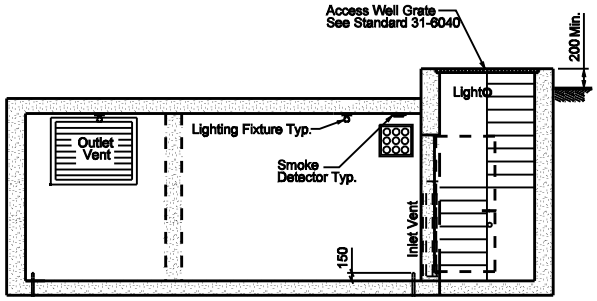
BELOW-GRADE VAULT SIZES					
TYPE	TX. RATING	L (m)	W (m)	X (m)	DOUBLE-DOOR SIZE (mm)
1	up to 2000 kVA	8.0	6.0	1.9	1200 x 2400 High
2	2500 - 4000 kVA	10.0	8.0	3.0	1200 x 3000 High



SECTION A-A



SECTION B-B



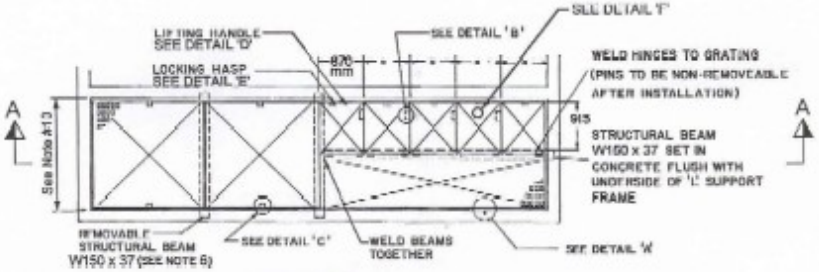
SECTION C-C

Reference	Standard
DESIGN AND CONSTRUCTION REQUIREMENTS	31–6000
TRANSFORMER VAULT DESIGN REQUIREMENTS	31–6010
STAIR & ACCESS WELL DETAILS	31–6040
LOUVER DETAILS FOR VENT OPENING	31–6050
BIRD SCREEN DETAILS	31–6060

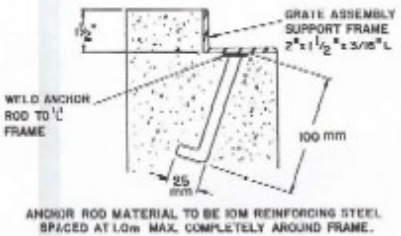
DISTRIBUTION CONSTRUCTION STANDARD

toronto hydro electric system

civil: G.D.	electrical: C.P.	CUSTOMER-OWNED STRUCTURES BELOW-GRADE TRANSFORMER VAULT			
original issue: 2003-11-27	scale: N.T.S.	rev. 4 G.D. - C.P. 2005-04-28	rev. 5	rev. 6	31-6030	1/1



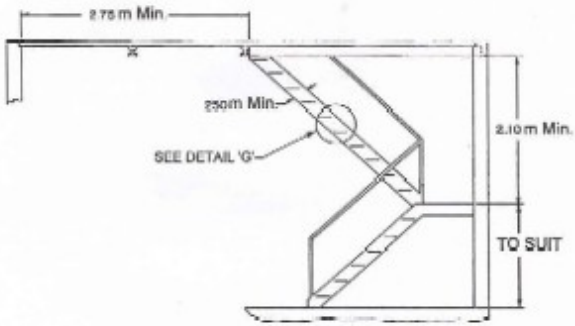
PLAN VIEW
ACCESS WELL GRATE ASSEMBLY



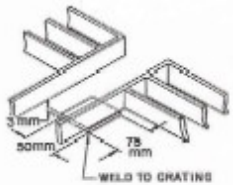
DETAIL "A"
ANCHOR ROD

NOTES -

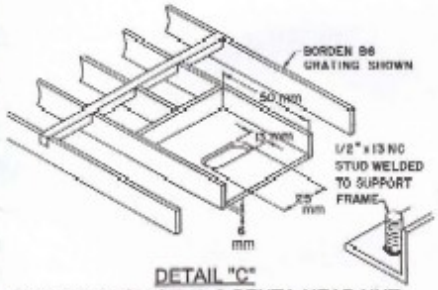
1. ALL METAL COMPONENTS TO BE HOT DIPPED GALVANIZED AS PER CSA SPEC. G-164. CLEANED, PRIMED AND PAINTED AFTER WELDING.
2. DETAILS SHOWN ARE INTENDED TO BE TYPICAL ARRANGEMENTS ONLY. SHOP DRAWINGS MUST BE ACCEPTED BY TORONTO HYDRO BEFORE CONSTRUCTION.
3. ACCESS WELL TO BE COMPLETE WITH STANDARD GRATING TYPE 'B6' AS MANUFACTURED BY BORDEN METAL PRODUCTS OR APPROVED EQUIVALENT.
4. LOCKING HASPS FOR GRATING TO BE SUPPLIED BY OWNER AS PER DIAGRAM. LOCKS WILL BE SUPPLIED BY TORONTO HYDRO.
5. PENTA-HEAD NUTS FOR GRATING WILL BE SUPPLIED BY TORONTO HYDRO.
6. BEAM IS TO BE SEATED IN A SUITABLE SADDLE (i.e. METAL, CONCRETE) WITH NO FASTENING DEVICES. (i.e. BOLTS).
7. STAIRS, HANDRAIL & GUARDS TO BE CONSTRUCTED TO ONTARIO BUILDING CODE REQUIREMENTS FOR AN EXIT STAIR AND SHALL BE INSTALLED IN A SECURE MANNER.
8. STAIRS, HANDRAIL & GUARDS TO BE OF ALL METAL CONSTRUCTION WITH WELDED JOINTS AND SHALL BE HOT DIPPED GALVANIZED AS PER CSA SPEC. G 164.
9. STAIR TREADS & LANDING TO BE I.S.G. SAFETY GRIP GRADING OR APPROVED EQUIVALENT.
10. REFER TO STANDARD 31-6020 & 31-6030 FOR LOCATION OF ACCESS WELL. WIDTH OF GRATING TO SUIT THE WIDTH OF ACCESS WELL.
11. ALL GRATINGS TO BE BOLTED DOWN.



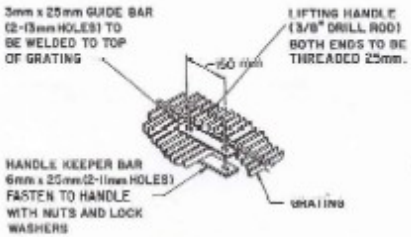
SECTION "A-A"



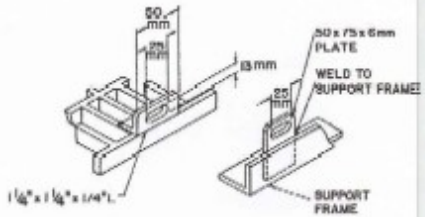
DETAIL "B"
HOLD DOWN PLATES



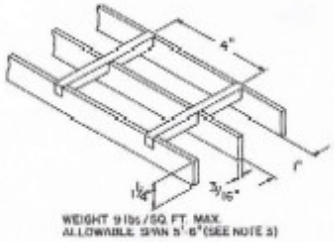
DETAIL "C"
BOLT PAD FOR STUD & PENTA-HEAD NUT
(IN AREAS SUBJECT TO PEDESTRIAN TRAFFIC)



DETAIL "D"
GRATE LIFTING HANDLE



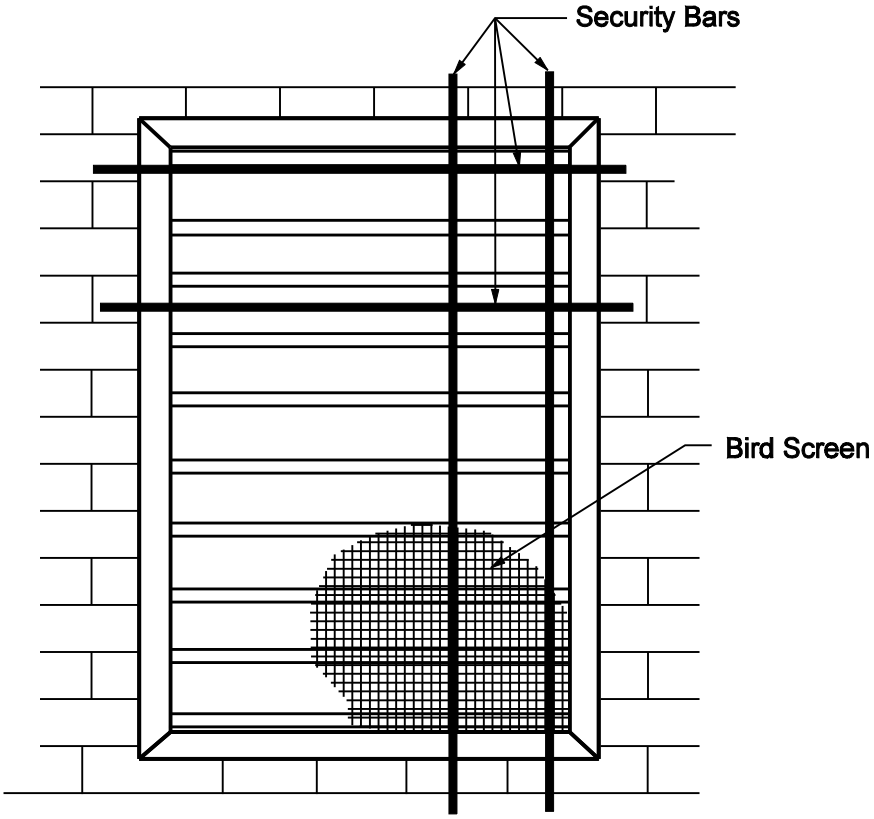
DETAIL "E"
TYPICAL GRATE LOCKING HASP



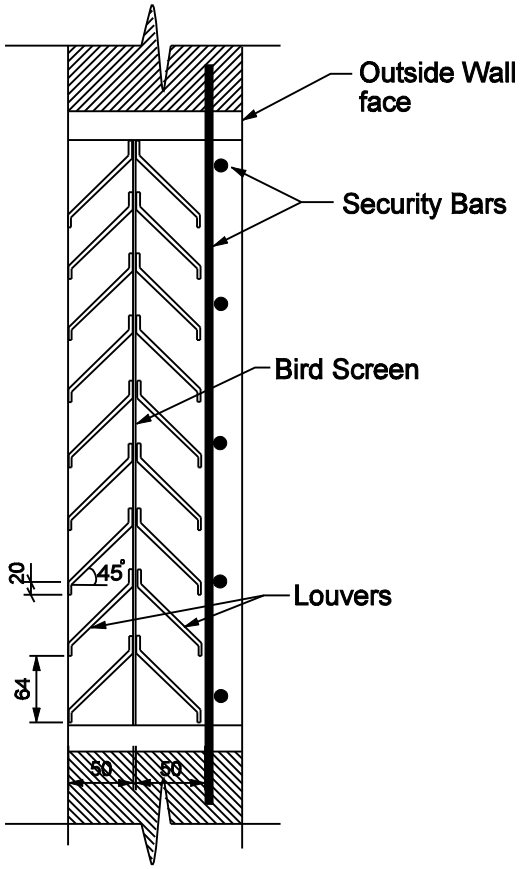
DETAIL "F"
TYPICAL GRATING

DETAIL "G"
SAFETY GRIP STAIR TREAD

DISTRIBUTION CONSTRUCTION STANDARD Civil Construction			CUSTOMER-OWNED STRUCTURES STAIR & ACCESS WELL DETAILS FOR BELOW-GRADE VAULTS				
toronto hydro	civil	electrical					
	original issue: 27 Nov. 03	scale: N.T.S.	rev. 1	rev. 2	rev. 3	31-6040	1/1



FRONT VIEW



CROSS SECTION

Notes:

1). All dimensions are in millimeters unless noted otherwise.

2). The allowable NET area of inlet and outlet openings for ventillation in vaults shall not be less than 19 sq. cm per kVA of maximum projected transformer capacity with a minimum of 930 sq. cm. The net area is based on the reduction in air flow due to double sided louvers, bird screen and security bars.

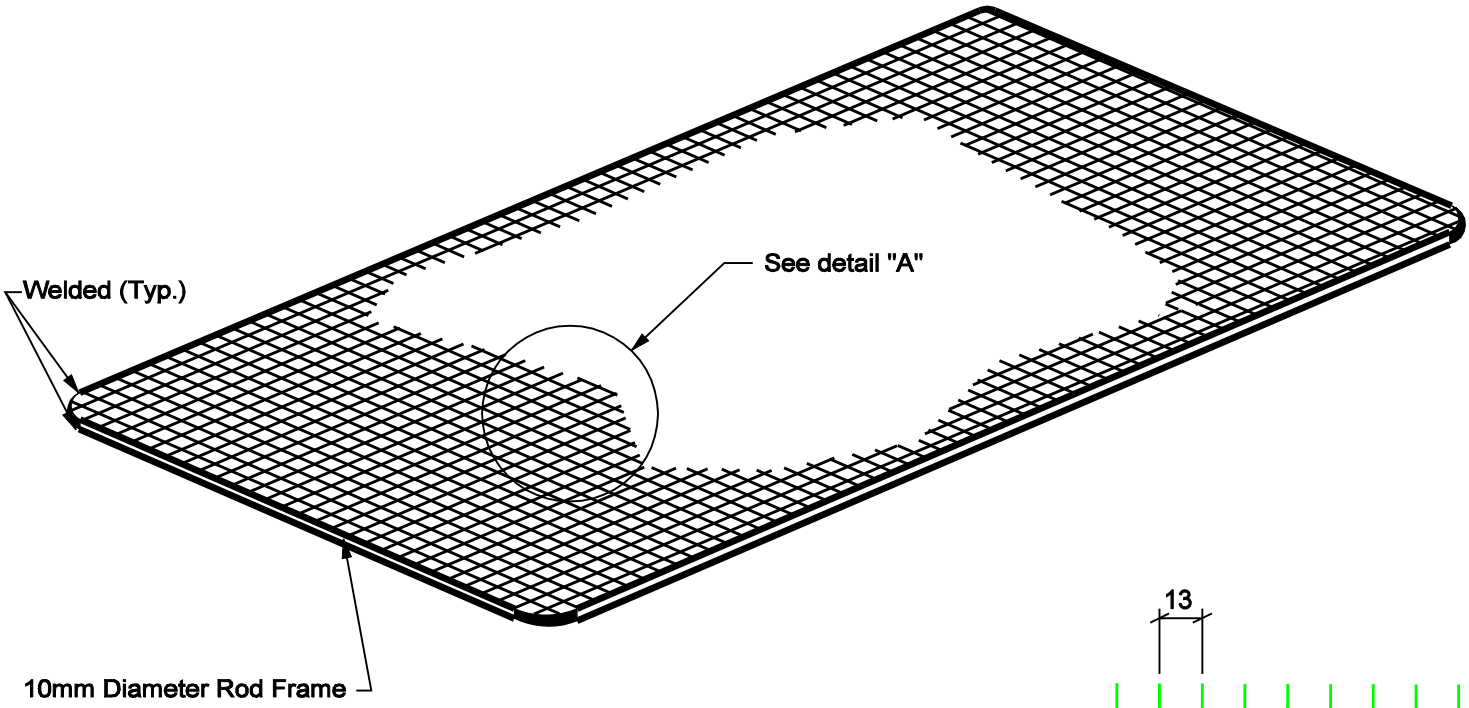
3). Vent openings to have 64mm spaced gabled double louver vent. Construction to be of minimum 16 gauge steel using 13mm square mesh bird screen. Both the vent & the screen to be galvanized as per CSA Standard G-164.

4). Refer to Standard 31-6060 for details of bird screen.

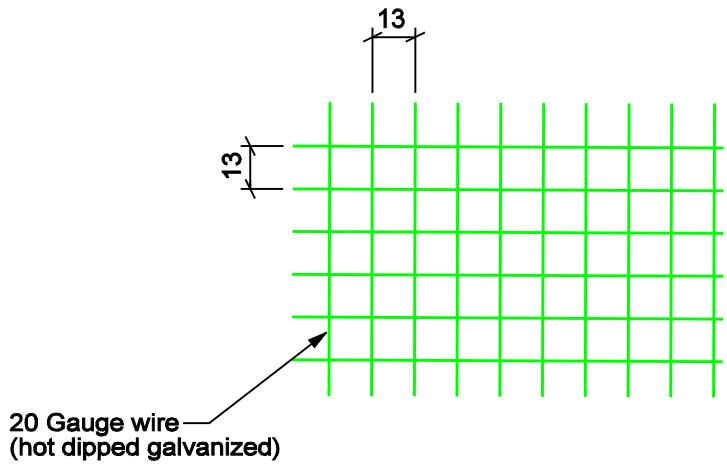
5). Shop drawings must be reviewed and accepted by Toronto Hydro before fabrication.

6). 15mm (#5) security bars to be mounted on wall, spaced vertically at 200mm centers and horizontally at 500mm centers with welds at intersecting points.

DISTRIBUTION CONSTRUCTION STANDARD Civil Construction			CUSTOMER-OWNED STRUCTURES LOUVER DETAILS FOR VENT OPENINGS				
toronto hydro	civil: G.D.	electrical: C.P.					
	original issue: 2003-11-27	scale: N.T.S.	rev. 1	rev. 2	rev. 3	31-6050	1/1



ISOMETRIC VIEW



DETAIL "A"

13mm Welded Wire Mesh

Notes:

1). All dimensions are in millimeters unless noted otherwise.

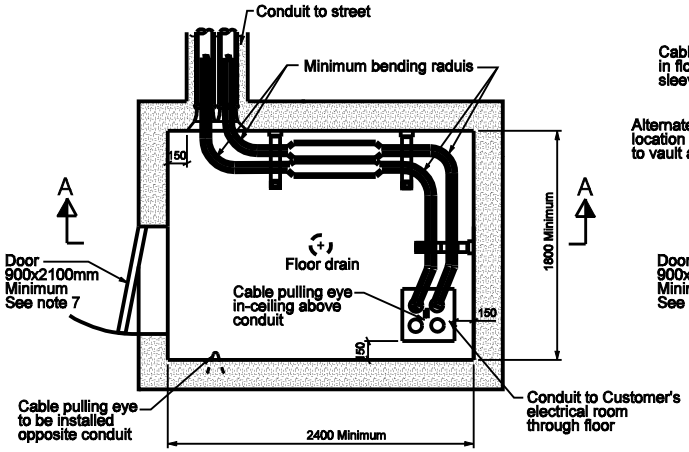
2). Bird Screen to be of metal construction with welded joints.

3). Bird Screen & all mounting hardware to be hot dipped galvanized after fabrication as per CSA G-164.

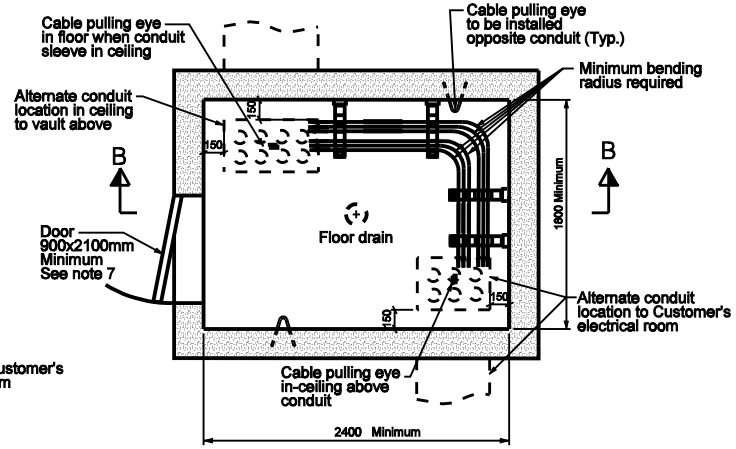
4). Shop drawings must be reviewed and accepted by Toronto Hydro before fabrication.

5). Refer to Standard 31-6050 for details of Louver Vent.

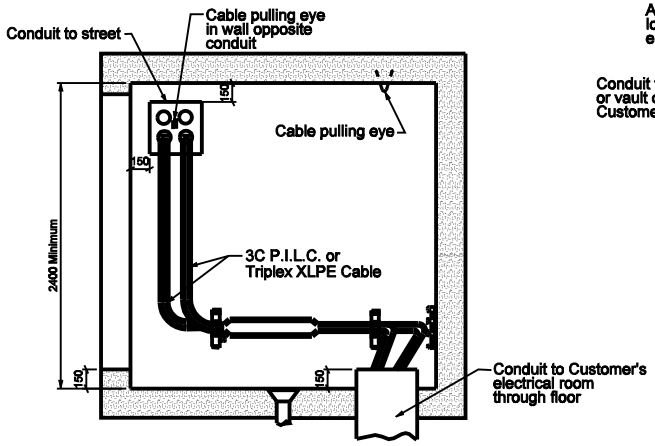
DISTRIBUTION CONSTRUCTION STANDARD Civil Construction			CUSTOMER-OWNED STRUCTURES BIRD SCREEN DETAILS				
toronto hydro	civil: G. D.	electrical: C. P.					
	original issue: 2003-11-27	scale: N.T.S.	rev. 1	rev. 2	rev. 3	31- 6060	1/1



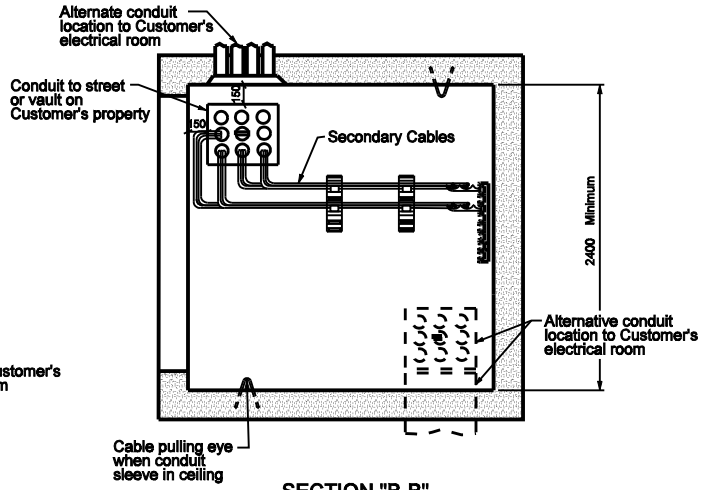
ROOM FOR HIGH-VOLTAGE CABLES PLAN



ROOM FOR LOW-VOLTAGE CABLES PLAN



SECTION "A-A"



SECTION "B-B"

Notes:

1). All dimensions are in millimeters unless noted otherwise.

2). When high voltage primary cables/ low voltage secondary cables are routed through the cable pull room, the following points are to be considered in determining the construction requirements and general layout:

a). It must, in all cases, be possible to make cable joints in the room.

b). Joints in cable must be horizontal.

c). The wall on which the cable joint is to be racked must be long enough to accommodate the joint, and two cable bends. The cable joint must be at least 300mm from the floor.

3). The walls of the room must be at least 2400mm long, and 1800mm wide, and the minimum headroom is 2400mm. Larger dimensions are required when:

a). Steps, railings, columns are located in the "clear" working area.

b). More than 2 circuits are installed.

c). Conduits are located such that the cables must encircle the pull room i.e., ducts located close together. Headroom dimensions to increase in such cases.

4). Cable pulling eyes are to be installed and located as per Standard 31-8210.

5). The conduit entrances should be near the corner s of the room and be as far apart as possible in the room, and should be offset from each other. Also, the ducts that go to the street must slope away from the Pull Room.

6). Lighting and drainage must be provided by the Customer. Light to be located in the center of room.

7). Pull room to be equipped with a door and frame having a fire rating of 1.5 hours.

8). Where possible, the doorway should be located opposite a duct face and positioned so that it does not interfere with jointing or cable installation.

9). Padlock hasp to be provided for door (or provision for Toronto Hydro cylinder lock - 29mm diameter cylinder).

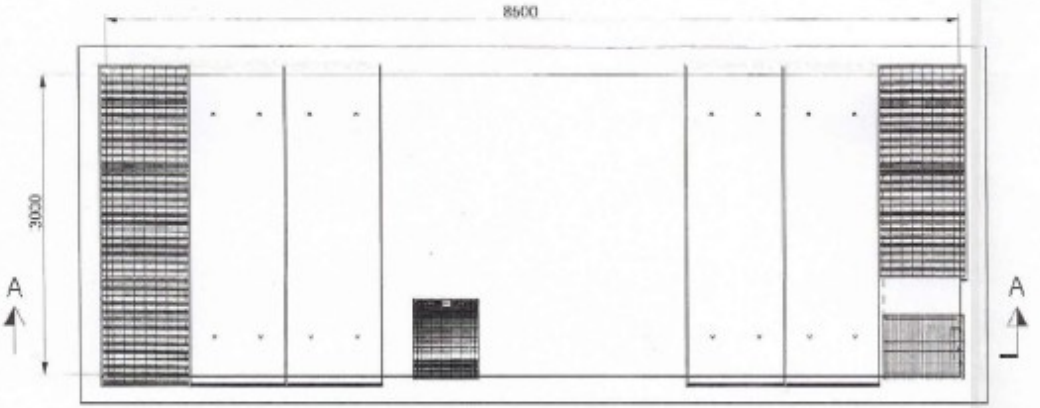
10). No foreign equipment or pipes are allowed in the Pull Room.

11). Cable racks and arms will be supplied and installed by Toronto Hydro and charged to the Customer.

12). 24 hr. access is required to Pull Room.

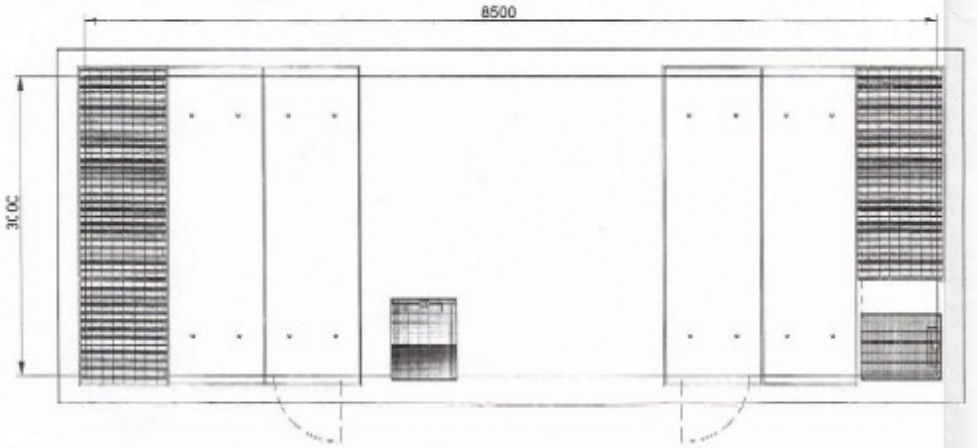
13). The above requirements are to be shown on the customer's drawings for Toronto Hydro's review and acceptance.

DISTRIBUTION CONSTRUCTION STANDARD Civil Construction			CABLE PULL ROOMS				
	civil: G.D.	electrical: C.P.	TYPICAL INSTALLATION OF HIGH & LOW VOLTAGE CABLES				
toronto hydro	original issue: 2004-07-30	scale: N.T.S.	rev. 1	rev. 2	rev. 3	31-6070	1/1



TOP-ENTRY

3000 x 8500 x 3660mm Head Room



BASEMENT-ENTRY

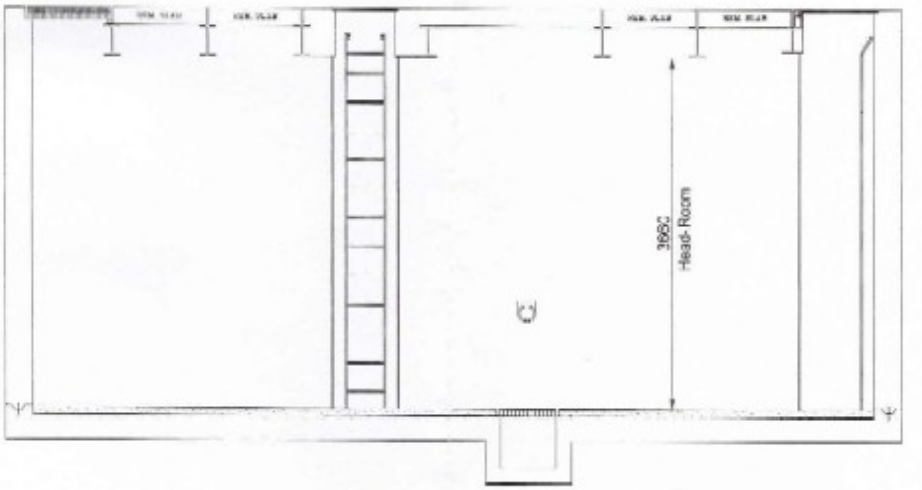
3000 x 8500 x 3660mm Head Room

General Notes:

1). All dimensions are in millimeters unless noted otherwise.

2). This drawing shall be read in conjunction with Standards 31-6000 and 31-6010.

3). Refer to standard 31-5410 for details.



SECTION A-A

DISTRIBUTION CONSTRUCTION STANDARD Civil Construction			CUSTOMER-OWNED STRUCTURES 13.8 KV RADIAL SYSTEM BELOW - GRADE VAULTS				
toronto hydro	original issue: 27 NOV - 03	electrical scale: N.T.S.	rev. 1	rev. 2	rev. 3	31-6080	1/1

toronto hydro

electric system

TORONTO HYDRO-ELECTRIC SYSTEM

METERING REQUIREMENTS
750 VOLTS OR LESS

FIRST EDITION: March 2003

REVISION #4: January 23, 2007

PREPARED BY: _____
ENGINEER, STANDARDS & MATERIALS SECTION

REVIEWED BY: _____
SUPERVISOR, STANDARDS & MATERIALS SECTION

CERTIFICATE OF APPROVAL THIS TECHNICAL SPECIFICATION MEETS THE SAFETY REQUIREMENTS OF SECTION 4 OF ONTARIO REGULATION 22/04	
R. Sironi, P. Eng. ROMANO SIRONI, P. Eng. MANAGER, POLICY & STANDARDS	Jan. 23, 2007 DATE

SECTION 6 - REFERENCE #6

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1. SCOPE

1.1 Toronto Hydro Requirements

This publication covers the requirements of Toronto Hydro, in addition to the requirements of the "Supply Authority" stated in the Ontario Electrical Safety Code, for service entrance, connection, and metering of electrical energy to Toronto Hydro customers for Permanent and Temporary Services.

1.2 Ontario Electrical Safety Code

Nothing contained in these Requirements shall prejudice or supersede any requirements of the Ontario Electrical Safety Code or affect regulations of existing building codes, unless specifically stated herein.

Some of these requirements identified by the latest edition of the Ontario Electrical Safety Code have been included for convenience and references purposes, even though they may be under the Electrical Safety Authority (ESA) jurisdiction.

Where reference is made to a particular Rule, then this should be taken also as a reference to an applicable Appendix.

2. PURPOSE

This document is intended to provide guidance to Toronto Hydro customers and their agents in the design, preparation of plans and construction of the proposed service installation with respect to revenue metering. The requirements apply to all new, rearranged or upgraded services, both permanent and temporary, and are intended to provide an efficient and safe supply of electrical energy with respect to revenue metering.

It shall be the responsibility of the customer to conform to the latest edition of the Toronto Hydro Requirements, the Toronto Hydro Conditions of Service and the Ontario Electrical Safety Code.

3. DEFINITIONS, PUBLICATIONS AND THE INTERNATIONALO SYSTEM OF UNITS

3.1 Definitions

3.1.1 In addition to the definitions stated in Section "0" of the Electrical Safety Code, the following meanings have been ascribed to the already defined or new terms.

Acceptable	Meets Toronto Hydro Requirements
Approval	Approval of drawings and customer's equipment is limited to Toronto Hydro's requirements and should not be construed as acceptance of liability due to faulty design and/or workmanships.
Compartment	A subdivision of a switchgear/switchboard unit.
Customer/ Consumer	The person or persons, firm, Corporation or their agents who request or use Toronto Hydro Services.
Service Entrance Equipment Sprinkler Proof Enclosure	An enclosure for indoor application so constructed or protected that water from sprinkler systems will not interfere with the successful operation of the enclosed Switchgear, excluding flooding.
Switchgear	A full height and full depth module of a switchgear or switchboard assembly. It is sometimes referred to as "cell", Unit, "cubicle" or "section".

3.2 Associated Publications and Standards

In addition to the applicable reference publications listed in the latest edition of the Ontario Electrical Safety Code, and all the applicable Toronto Hydro Standards the following publications shall also apply:

- Toronto Hydro Conditions of Service.
- Ontario Electrical Safety Code
- CSA Standard, C22.2 No. 4, Enclosed Switches
- CSA Standard, C22.2 No. 31, Switchgear Assemblies
- CSA Standard, C22.2 No. 115, Meter Mounting Devices
- EEMAC Standard for Switchgear Assemblies G8 – 2
- MEA (of Ontario) Guide to Municipal Standard Construction Part V-Metering and Service Entrance Equipment
- Electrical and Electronic Manufacturers Association for Revenue Metering Equipment in Switchgear Assemblies G10-1
- Ontario Building Code
- The Occupational Health and Safety Act and Regulations for Industrial Establishments
- CSA Standard, C235-83 – Preferred Voltage Levels for AC Systems 0 to 50,000 V.

NOTE: All publications shall be of the latest edition.

3.3 The International System of Units

SI units have been used in this publication for measurements and weights. The metric units have been rounded as close as possible to the previously used units. Equipment or materials not available in metric units shall be equal to or larger than the units specified in this publication. Equivalent substitution shall have prior approval from Toronto Hydro.

All drawings submitted by customers shall be in metric units.

4. PROCEDURE FOR SERVICE APPLICATION

4.1 Approval Routine

4.1.1 Initial Data Requirements

Application for supply of service shall include service address, load details, size and location of service and desired service date.

4.1.2 Drawings Required

Once the type of service has been determined, detailed drawings and specifications shall be submitted for review and acceptance. (see Section 4.2.)

4.1.3 Approvals Prior to Manufacture

Manufacture or work associated with the installation of equipment should start only after the design has been reviewed and accepted by Toronto Hydro.

4.2 Engineering Drawings and Specifications

4.2.1 Drawings Required for Acceptance

Fully dimensioned and scaled drawings submitted for Toronto Hydro's review and acceptance shall include but not be limited to the following list. The minimum number of copies of drawings required is indicated in brackets. The requirement may change without notice.

(a) Electrical room layout drawing showing the location of the electrical switchboard and all revenue metering (meter cabinets and or meter centres). (2)

(b) Single line distribution diagram. (2)

(c) Manufacturer's or shop drawings of the proposed switchboard, with a utility compartment detail drawing. (2)

(d) Meter center drawings (2)

Note: Additional drawings may be requested.

4.2.2 Drawing Revisions

If any drawings require revision Toronto Hydro will determine the number of copies of each drawing to be re-submitted for further review and acceptance.

4.3 Customer's Responsibilities - Service Change, Relocations and New Services

4.3.1 Meter Disconnection, Storage and Pick-up

When work is required on the customer's service entrance equipment, it shall be the responsibility of the customer or the customer's representative to:

(a) Notify Toronto Hydro of intention to disconnect a meter or metering equipment before removing any such equipment.

(b) Store the removed equipment in a safe place on site and immediately advise Toronto Hydro of this location for pick-up. Toronto Hydro will charge for lost or damaged meter (s) or metering equipment.

(c) Tag meter with the following information:
- date of removal
- address
- customer's name and telephone number

5. SERVICE ENTRANCE and ELECTRICAL ROOMS

5.1 General Requirements

5.1.1 Residential Outdoor Meters

Meters for new, changed or relocated residential services shall be mounted outdoors.

5.1.2 Non-Residential Outdoor Meters – 300 Volts or Less

Meters for other than residential services may be mounted outdoors in a weatherproof enclosure if an acceptable location is available.

5.2 Legislation and Specified Requirements

Where a service entrance electrical room contains a switchboard, the means of egress from such a hazardous room shall conform to the latest revisions of the Ontario Building Code and to the Ontario Occupational Health and Safety Act and Regulations for Industrial Establishments.

5.3 Exit Doors & Hardware

In addition to Section 3.4 of the Ontario Building Code on "Exits", the following shall be provided:

Exit Doors

(i) Exit doors shall open in the direction of exit travel and shall be equipped with panic type hardware.

(ii) No exit door shall open directly to the street or open space where there is danger of blockage from ice or snow and pedestrian or vehicular traffic. Such situations shall be discussed with Toronto Hydro to find solutions.

(iii) Exit doors shall be clearly identified.

5.4 600 Volt Delta and 347/600 Volt Y – In Electrical Rooms

600 V delta and 347/600 V Y services are NOT ACCEPTABLE in the same electrical room.

5.5 Fire Pump Services

1) Pending ESA approval; where the service cables for a fire pump service are 3/0 or less, the fire pump service shall be metered using an approved meter mounting device (meter socket).

2) Where the service cables for a fire pump service are larger than 3/0, the fire pump service shall be metered using a 1220mm x 1220mm x 305mm (48" x 48" 12") meter cabinet.

6. SWITCHBOARDS

6.1 Compartments

6.1.1 Compartment Isolation

The following items of equipment shall be isolated by means of separate compartments:

(a) Each service entrance switch or breaker (CSA Standard C22.2 No. 4).

(b) Each set of Toronto Hydro revenue metering instrument transformers.

NOTE: Barriers shall be installed between metered and unmetered sections.

6.2 Electrical Clearances

6.2.1 CSA Requirements

Where cable or bus connections are made to any component supplied or installed by Toronto Hydro (i.e. revenue metering current and voltage transformers), such connections shall be assumed to be bare conductor and full clearances shall be maintained in accordance with the following CSA table and the foot note:

Table 3 of CSA Standard C22.2 No. 31, M89

Nominal voltage Rating (v)	Minimum Spacing (mm)			
	Opposite Polarity		To ground	
	Through Air	Over Surface	Through Air	Over Surface
120 ac	12.5	19	12.5	19
240 ac	19	31	19	25
480 ac	22	44	22	34
600 ac	25	50	25	38

NOTE: Where a neutral is involved, the spacing between the neutral and other current-carrying parts may be based on the lower voltage that normally occurs between them. The spacing from neutral to grounded metal parts are to be the same as those between the current carrying conductors and grounded metal parts.

6.3 Equipment Access Doors

6.3.1 Equipment Working Space Requirement

Doors with vertical hinges shall be installed on the electrical cabinets and compartments containing live equipment where Toronto Hydro personnel will be required to work, such as service entrance switches, metering compartments, switchboard covers over main breakers and unmetered sections of the switchboards.

6.3.2 Provision for Sealing and Padlocking Equipment Access Doors

Hinged doors as described in 6.3.1 shall have provision for sealing. Where bolts are used for fastening they shall be of the captive knurled type with minimum 25mm diameter slotted heads.

Equipment access doors shall be equipped with padlock hasps measuring at least 30mm wide by 5mm thick capable of accepting a standard Toronto Hydro padlock with a 8mm shackle.

6.3.3 Equipment Access Door Openings

All hinged outer access doors shall open at least 135° and all hinged inner doors or screens shall open at least 90°.

7. TORONTO HYDRO REVENUE METERING EQUIPMENT

7.1 General Information

7.1.1 Scope of Supply

Toronto Hydro will supply all meters, instrument transformers and secondary wiring required for revenue metering. All revenue metering equipment shall remain the property of Toronto Hydro.

7.1.2 Customer's Instrumentation

(a) Customer's instrumentation shall be connected on the load side of the Toronto Hydro metering.

(b) Customer's relays, instruments or other devices shall not be connected in the metering circuit.

(c) Bottom connected A and P base type meters shall not be used as splitter boxes.

7.2 Metering Instrument Transformers

7.2.1 Instrument Transformer Data

Toronto Hydro will provide the manufacturer's name, type and rating of metering instrument transformers. Additional information, if required, will be available at the request of the customer.

7.2.2 Meter Enclosures

All metering instrument transformers and associated meters shall be installed in approved enclosures.

7.2.3 Metering Transformers on Load Side

Metering transformers shall be connected on the load side of the main fused switch or circuit breaker, excluding approved 400 amp single phase sockets.

7.2.4 Mounting Arrangements

Provision shall be made by the customer for mounting the metering transformers (See 7.4 and 7.5) including the supply and installation of all material for the primary connections to the current transformers.

7.3 Space Requirements for Meters without Instrument Transformers

7.3.1 Space for Meters Only

Minimum space requirements for meters are shown in Table I. All dimensions are in mm.

TABLE I

Meter Type	Phase	No. of Meters	Cabinet Size (min.)	Socket Type
Self-contained up to 200 A 600V	Poly or single phase	1	Not applicable	CSA/UL Approved
Transformer Rated Bottom Connected	Single or Poly	1 **or** 2	915w x 915h x 305d	Not Applicable
*RIMS Metering Transformer-rated Bottom Connected	3PH 3Wire	1	915w x 915h x 305d	TSU8; CT108; CTS800PW – See Diag. #4 for layout. See Note 1 below.
	3PH 4Wire	1	915w x 915h x 305d	TSU13; CT113; CTS130PW – See Diag. #4 for layout. See Note 1 below.
*Transformer rated Socket (S base)	3PH 3Wire	1	Not applicable	TSU8; CT108; CTS800PW
	3PH 4Wire	1	Not applicable	TSU13; CT113; CTS130PW
Transformer-rated Socket (S base) 201-400 Amp; 240 V. Residential/ Commercial	Single	1	Not applicable	JS4AB-300/5; CT4-TSB3 See Diag. #3 For Wiring

***Where metering transformers are located remotely (i.e. in switchboard).**

Note 1: Not applicable for totalized services.

7.3.2 Multiple Metering Points

Where there are multiple metering points requiring more than one set of metering transformers to be totalized, or where a recording instrument or special equipment is required, Toronto Hydro shall be consulted regarding cabinet size.

7.4 Space Requirements for Meters with Instrument Transformers

7.4.1 Space for Meters and Transformers

Minimum cabinet size for meters, instrument transformers and associated equipment is shown in Table II. All dimensions are in mm.

TABLE II

Voltage (V)	Phase	Wire	Main Switch Size	Cabinet Size (Min.)
120/240	1	3	>400 – 800 A.	1220w x 1220h x 305d
600* 120/208 347/600 Y	3 3	3 4	>200 – 800 A.	1220w x 1220h x 305d
240/416*	3	4	>200 - 800 A.	1220w x 1220h x 305d

*For existing services only.

Note: (1) A larger cabinet or 2 separate cabinets may be required:
(a) Where cable size exceeds the main switch capacity.
(b) Where more than 2-500 kcmil CU or 2-750 kcmil AL are used.
(c) Where meter cables do not enter the meter cabinet in a location to permit efficient use of space.

(2) Meter cables in a meter cabinet will be located so that the most efficient use of the space is accomplished. Diagram #2 shows the preferred meter cabinet area that will be utilized for the installation of meter (s) and accompanying test switches. The cables and instrument transformers must not encroach on the metering area shown in the diagram.

(3) Once the meter cabinet has been installed, but before the conduit/corflex cable has been installed, the customer/electrician **must** contact the Toronto Hydro Meter Services Department Crew Leader (see diagram #2 for phone numbers) to arrange for metering inspection.

(4) Where main switch capacity exceeds 800A, a switchboard is required with a separate revenue metering compartment. See Section 7.11 for details.

(5) A neutral wire is required for metering 120/208 and 347/600 volt services. The customer shall provide and install a full size neutral cable (white) from the neutral bus in the main switch or splitter to the meter cabinet. The neutral is to terminate at an insulated neutral block. See diagram #2.

7.5 Meter Cabinets

7.5.1 General

(a) Meter cabinets containing Toronto Hydro equipment shall not be used as splitter boxes.

(b) Meter cabinets, installed outdoors or where sprinklers are used, shall be weatherproof type.

(c) Meter cabinets installed outdoors shall be equipped with door stops.

7.5.2 Material

All meter cabinets shall be made of sheet steel, #16 MSG minimum.

7.5.3 Doors

Meter cabinets for indoor and outdoor installation shall be equipped with vertically hinged doors. Cabinets 915mm x 915mm x 305mm or larger shall have double doors opening at the center.

7.5.4 Locking and Sealing

Meter cabinets for indoor and outdoor installation shall be equipped with door latch and handle (or combination latch-handle) with provision for a Toronto Hydro padlock and seal.

7.5.5 Mounting Panel (Back Plate)

Meter cabinets shall be equipped with removable #16 MSG min. sheet metal interior panels. The panel shall be 75mm narrower and 75mm shorter than the meter cabinet and mounted with a clearance of 15mm behind it.

7.6 Mounting Height for Meter Cabinets

7.6.1 Minimum – Maximum Heights

Minimum distance from floor to base of cabinets shall be 600mm.
Maximum distance from floor to top of cabinets shall be 2000mm.

Note: Any deviation from these dimensions shall require Toronto Hydro approval

7.7 Freedom from Vibration

7.7.1 Mounting

Meter cabinets and panels shall be mounted so as to be free from vibration and mechanical shock.

7.8 Meter Cables

7.8.1 Cable Length, Material, Type & Size

(a) Where instrument transformers are installed in a meter cabinet the minimum length of each meter cable, both line and load side, shall be 1200mm.

(b) Mineral insulated solid or hard drawn wire conductors are not acceptable for meter cables.

(c) Line and load meter cables shall be identical in type, number of conductors and wire size.

(d) Meter cables shall be on the load side of the main switch or breaker.

7.8.2 Entry Points

Line and load entry points shall be located so that meters and/or instrument transformers can be mounted to permit efficient use of space provided. [See 7.4.1 note 2 and Diagram #2].

7.8.3 Primary Connections in Meter Cabinet

The customer/electrician shall make all primary connections on the meter cables in the meter cabinet:

a) The customer/electrician is to contact the Toronto Hydro Meter Services Department Crew Leader (see diagram #2 for phone number) to arrange installation of the metering current transformers.

b) Once the metering transformers have been installed, the customer/electrician is to either insert the primary meter cables through the window type current transformers or make compression sleeve connection on the primary meter cables. Should bar type metering current transformers be used, then the customer/ electrician shall make compression type terminal lug connections to the bar type metering current transformers. Mechanical connections are not acceptable.

c) The customer/electrician shall supply all compression sleeves and or compression lugs.

d) Toronto Hydro will wrap all the connections at the current transformers.

NOTE: Any deviation from these dimensions shall require Toronto Hydro approval.

7.9 Socket-type Meter Mounting Devices – 200 Amps or Less

7.9.1 Customer Supplied Devices

(a) Meter mounting devices shall be provided and maintained by the customer, be of a type approved by Toronto Hydro and conform to the latest edition of CSA Standards.

(b) Round and shallow square meter mounting devices are not permitted.

(c) Meter mounting devices shall have a supplied metal sealing ring.

(d) Automatic bypass devices are not permitted.

(e) Meter mounting devices installed indoors shall be on the load side of the service switch.

(f) Meters for new and upgraded residential services shall be mounted outdoors in a location approved by Toronto Hydro.

7.9.2 Approved-Type Devices

(a) Meter mounting devices are required for all services up to 200A. The requirements are indicated below and shown in Diagram #1.

120/240V	1 Phase	3 Wire	4-jaw socket
120/208V	1 Phase	3 Wire	5-jaw socket
120/208V	3 Phase	4 Wire	7-jaw socket
347/600V	3 Phase	4 Wire	7-jaw socket
600V*	3 Phase	3 Wire	5-jaw socket

* (Existing Services Only)

(b) Dual socket meter mounting devices are not permitted.

(c) Ringless meter mounting devices are not permitted.

7.9.3 Rating

(a) Approved meter mounting devices shall have a minimum rating of 100A, and be rated no less than the service capacity. For example, a 125A service requires a 200A meter-mounting device.

(b) All new and upgraded residential services rated up to 200A shall utilize an approved meter mounting device.

7.9.4 Mounting and Space Requirements

(a) Meter mounting devices shall be installed in an acceptable manner and location. They must be mounted level in the horizontal and vertical planes (see Diagram #1 for terminal arrangements) at heights indicated below:

Outdoors – The centerline of the meter shall be 1700mm ± 100mm.

Indoors – The centerline of the meter shall be approximately 1700mm but in no case shall it be more than 1800mm or less than 600mm.

(b) A clear space of 400mm w x 600 mm h shall be provided for each meter mounting device.

7.9.5 Energization Prior to Installation of Meter

When the service is to be energized prior to the installation of the meter, acceptable temporary jumper bars may be used in the meter mounting devices. Should the meter jaws be found to be damaged by improper use of jumpers, the customer shall replace the meter socket.

7.10 Service Identification

7.10.1 Marking and Labeling of Service Boxes and Equipment

(i) The customer shall permanently and legibly identify each metered service with respect to its specific address which shall include the store or apartment number, where applicable.

(ii) The identification shall be applied to all service switches and circuit breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to their service switches or circuit breakers.

(iii) Non-permanent markers or paper labels are not acceptable on equipment which requires identification.

7.11 Metering Requirements for Enclosed Switchboards

7.11.1 Separate Compartment

A separate compartment with a vertically hinged access door having provision for sealing and locking shall be provided for each set of metering instrument transformers for the exclusive use of Toronto Hydro. See Section 6.3 for sealing and locking requirements.

7.11.2 Mounting Hardware

Mounting bolts or nuts shall be installed in a manner which will permit complete installation and/or removal of the instrument transformers from within the compartment in which they are installed. Fixed mounting nuts or bolts shall be required for this purpose.

7.11.3 Installation by Manufacturer/Customer

(a) When the switchboard drawings have been approved, the metering instrument transformers will be delivered upon request to the switchboard manufacturer for installation in the switchboard. The current transformers shall be installed with the polarity marks on the line side. The type and rating of instrument transformers to be supplied shall be determined by Toronto Hydro.

(b) Metering instrument transformers delivered to the site by Toronto Hydro are to be installed in the switchboard by the customer/manufacturer.

(c) All hardware, bus work and/or cable required for primary connections to metering current transformers shall be provided by the customer or the switchboard manufacturer.

(d) The customer and or manufacturer shall not disassemble and/or change in any manner the Toronto Hydro equipment sent to them.

7.11.4 Window Type Current Transformers

(a) Where window-type current transformers are to be installed, the bus shall be sectionalized. The removable bus links through the current transformers shall be bolted in the vertical bus section directly above and below the current transformers. Where three window-type current transformers are used, they shall be mounted in a staggered arrangement.

(b) Where window current transformers are used and the switchboard bus is larger than the window opening, the customer or switchboard manufacturer shall modify the bus to accommodate the current transformers.

(c) The instrument transformers will be supplied by and will remain the property of Toronto Hydro.

7.11.5 Voltage Transformers

Where required provision shall be made for the installation of voltage transformers on a #16 MSG steel panel in an accessible location in the instrument transformer compartment. This panel must not obstruct access to the current transformers or the removable bus links through the current transformers. This panel is to be a minimum of 140 mm from the front of the instrument transformer compartment.

The voltage transformers are to be installed in the instrument transformer compartment by the switchboard manufacturer and/or electrician on site.

7.11.6 Neutral Bus Tap

A readily accessible continuous neutral copper bus of 25mm x 3mm or equivalent (#6 copper white TW75 wire), with three 10-24 tapped holes, shall be provided in each instrument transformer compartment for all 3 phase 4 wire services. If the main neutral bus passes through a metering instrument transformer compartment, the bus shall be provided with three 10-24 tapped holes.

7.11.7 Grounding Stud

A readily accessible grounding stud with a connector suitable for a #10 copper wire or a ground bar provided with three 10-24 tapped hole shall be provided in each instrument transformer compartment. The grounding facility in the compartment shall be connected directly to the switchboard ground bus.

7.11.8 Compartment Sizes

Minimum metering transformer compartment size in mm are given in Table III.

TABLE III

METERING INSTRUMENT TRANSFORMER COMPARTMENT – MINIMUM SIZES

Metering Transformers and Compartments						
Voltage (Volts)	Phase	Wire	Service Size (Amperes)	Compartment Size	Number of Metering Transformers (Provision for)	
					Current	Voltage
240/120 208/120 N/W	1 3	3 3	Up to 800	A	1 or 2	0
			Over 800 Up to 4000	B		
208/120 416/240 600/347	3	4	Up to 800	A	3	3
			Over 800 Up to 4000	B	3	
600*	3	3	Up to 800	A	2	2
			Over 800 Up to 4000	B	2	
Voltages up to 600	(*) 3 3	(*) 3 4	Over 4000	C	2 3	2 3

* For existing services only.

COMPARTMENT SIZES [width x height x depth (from CT mounting plate)]

A - 762mm x 762mm x 210mm (30” x 30” x 8.25”)
B - 965mm x 762mm x 324mm (38” x 30” x 12.75”)
C - 965mm x 914mm x 381mm (38” x 36” x 15”)

7.12 Meter Cabinets and Conduit Requirements

7.12.1 Location of Meter Cabinet

Meter cabinets associated with revenue metering transformers mounted in a switchboard shall be located in an approved location close to the switchboard.

7.12.2 Conduit and Metering Compartment

A separate conduit (to be continuous within the switchboard) is required from each revenue metering compartment to the meter cabinet. The meter conduit is to terminate at the front right or left corner of the revenue metering compartment and be unobstructed.

7.12.3 Conduit Length and Size

The maximum length of conduit shall be no longer than 30m. The customer shall supply and install a conduit of a nominal diameter of not less than 38 mm.

7.12.4 Conduit Fittings and Covers

(a) The number of bends shall be kept to a minimum, but in no case shall there be more than three 90 degree bends.

(b) The metering conduit run within the switchboard and between the switchboard and the meter cabinet shall not have fittings with removable covers. Pull boxes and or 'LBs" are not permitted.

(c) The 38mm metering conduit between the revenue metering instrument transformer compartment in the switchboard and the meter cabinet is to be rigid steel, EMT or PVC. Flexible conduit is not permitted.

7.12.5 Pull Line In Conduit Run

The customer shall install a strong nylon or polyrope pull line in the conduit between each revenue metering transformer compartment and the meter cabinet. An excess of 1500mm loop shall be left at each end.

7.12.6 Connection of Meter Wires

Under no circumstances will Toronto Hydro install and connect meter wires unless the service is de-energized.

7.12.7 Meter Cabinet Bonding

The meter cabinet is to be bonded to the system ground in accordance with the Ontario Electrical Safety Code.

7.13 Meter Centres

7.13.1 Provision for Sealing

The customer shall make provision for the installation of Toronto Hydro seals on the following:

(a) removable covers and doors which provide access to unmetered circuits.

(b) handles of all circuit breakers in the "OFF" position.

7.13.2 Provision for Padlocking

Circuit breakers or fused switches protecting a meter socket shall have provision for padlocking in the open position.

7.13.3 Approved Meter Socket Assemblies

Only meter socket assemblies listed in Section 7.9.2 shall be used in Meter Centres. The meter sockets shall be properly aligned and mounted on a rigid base to prevent subsequent misalignment.

7.13.4 Protection of Meter Mounting Devices

Each meter-mounting device shall be protected by a rated circuit breaker having adequate short circuit interruption capacity. The circuit breaker shall be connected ahead of the meter-mounting device commonly known as "cold" metering.

7.13.5 Identification of Socket and Cover

Each removable meter socket and circuit breaker cover shall be identified by a permanent and unique mark (number, letter, etc.) so that it cannot be interchanged with other similar covers. The same identification mark shall appear on the frame of the meter centre at the compartment where the cover belongs and shall be clearly visible when the covers and meters are in place. This identification mark need not be the number of the suite metered, thus making it feasible to have the identification marks applied during manufacture of the meter centre.

7.13.6 Identification of Individual Service

Each circuit breaker required for an individual service shall have a permanent customer identification plate (metal or engraved plastic) which cannot be erased or obscured by paint. The circuit breakers must easily be recognized.

7.13.7 Positioning of Meters

(a) The centerline of the lowest meters shall not be less than 600mm from the finished floor level. The centerline of the upper meters shall not exceed 1800mm from the finished floor level.

(b) The minimum horizontal distance between the adjacent meter and sockets shall be 152mm rim-to-rim.

(c) The minimum vertical distance rim-to-rim between the adjacent meter socket openings shall be as follows:

(i) 76mm: for 100A, 4 or 5 jaw.
(ii) 152mm: for 100A, 7 jaw.
(iii) 152mm: for 200A, 4, 5 and 7 jaw.

7.13.8 Neutral for Meters

Where a neutral is required for metering, the meter mounting device shall have a pre-wired neutral connection (see Diagram #1). This neutral connection shall be ungrounded. The connection to the 5th or 7th terminal, if not made directly to the distribution neutral bus, shall be not less than #12 AWG copper or equivalent. Where a connection is to be made between aluminum and copper conductors, a proper bi-metallic connector shall be used.

7.13.9 Barrier for Meters

Each meter socket shall be separated from others by a suitable barrier.

7.13.10 Sealing Ring

Each meter socket shall be equipped with a metal sealing ring.

7.14 Remote Metering (RIMS) – Services 200 kW and Greater

The customer is to provide and install the following:

(a) 1-13mm (1/2”) EMT or PVC conduit complete with bushings at both ends between the revenue metering cabinet/ebox and the telephone room (punch-board). The 13mm (1/2”) conduit is to terminate at the top right corner of the meter cabinet/ebox.

A 2 pair (4 conductors) telephone cable is to be installed in the 13 mm (1/2") conduit. A RJ11 (4 pin) telephone jack is also to be provided and installed on the telephone cable in the meter cabinet/ebox. The telephone jack is to be left at the bottom of the meter cabinet/ebox with enough telephone cable to allow mounting the jack anywhere in the cabinet/ebox. The telephone cable terminating in the telephone room is to be clearly labeled "TORONTO HYDRO METERING".

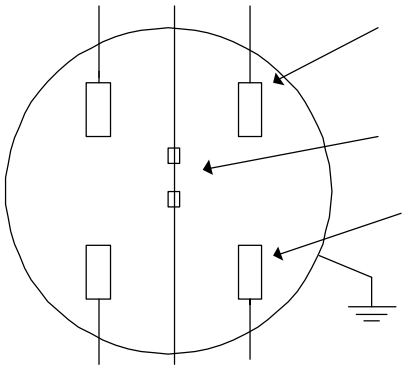
(b) Toronto Hydro will arrange to have the telephone line activated. Customer owned telephone lines or customer shared telephone lines are not acceptable.

(c) 1 – 120 Volt duplex receptacle, to be located at the bottom right corner inside the meter cabinet/ebox. The receptacle is to be connected to an uninterruptible power supply (UPS) if available.

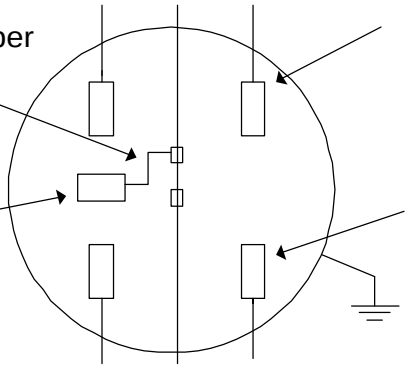
(d) The name and phone number of an on site contact person.

Diagram # 1

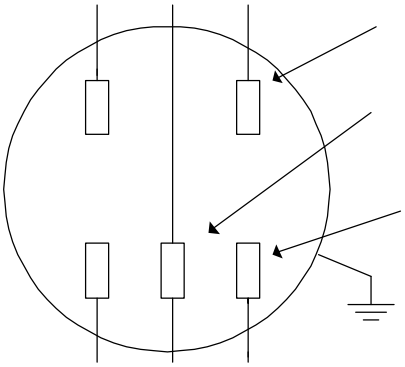
Terminal Arrangements for Meter Mounting Devices



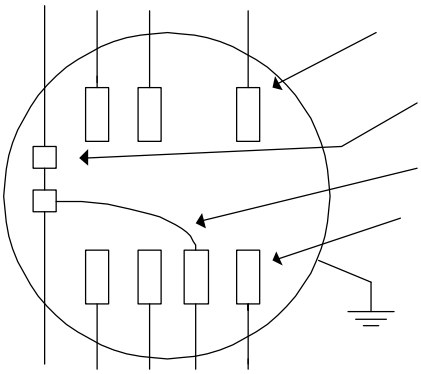
120/240
Single Phase



120/208, Two Phase plus Neutral



600 Volt
3 Phase, 3 Wire

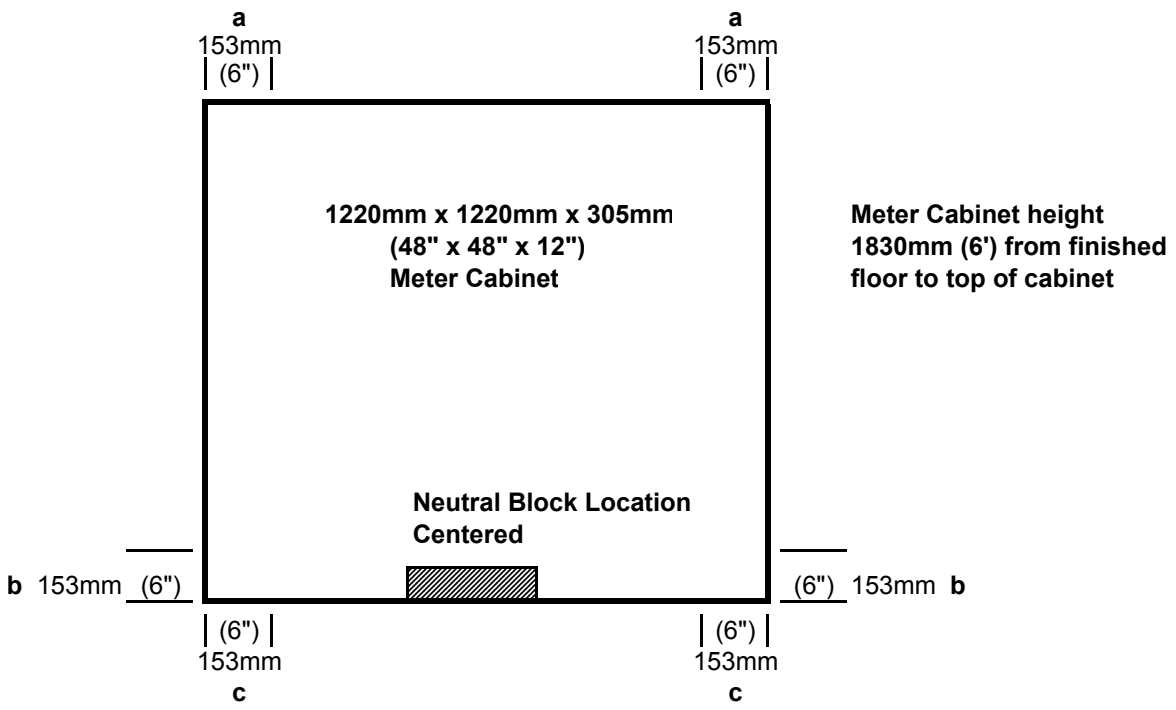


3 Phase 4 Wire

Revison Date: 03/01/14

Cabinet Layout for CTs/PTs Located Within the Meter Cabinet

Diagram # 2



1. Entry and exit points must be at points **a to a, b to b or c to c**. Any other conditions require approval from Meter Crew Leader from the district you are working within.

2. The electrican will inform the Meter Crew Leader once the meter cabinet is mounted but before the conductors are pulled in. The Crew Leader will the arrange for the installation of the metering equipment. All new jobs will utilize window type current transformers. The current transformers must be installed prior to the electrican pulling in the conductors.

3. The electrican will be responsible for pullling the cables through the appropriate current transformers and ensuring that phases correspond in cases of multiple conductors per phase. The electrican will lock off the switch until the metering installation is complete and all conditions are met with Toronto Hydro Electric System and ESA.

4. The electrican will be responsible for any splices, sleeve or lugs in the meter cabinet once the cable is pulled through the current transformers. Toronto Hydro will **not** provide any material for splices. Compression sleeves are recommended. All spice material must pass inspection by ESA.

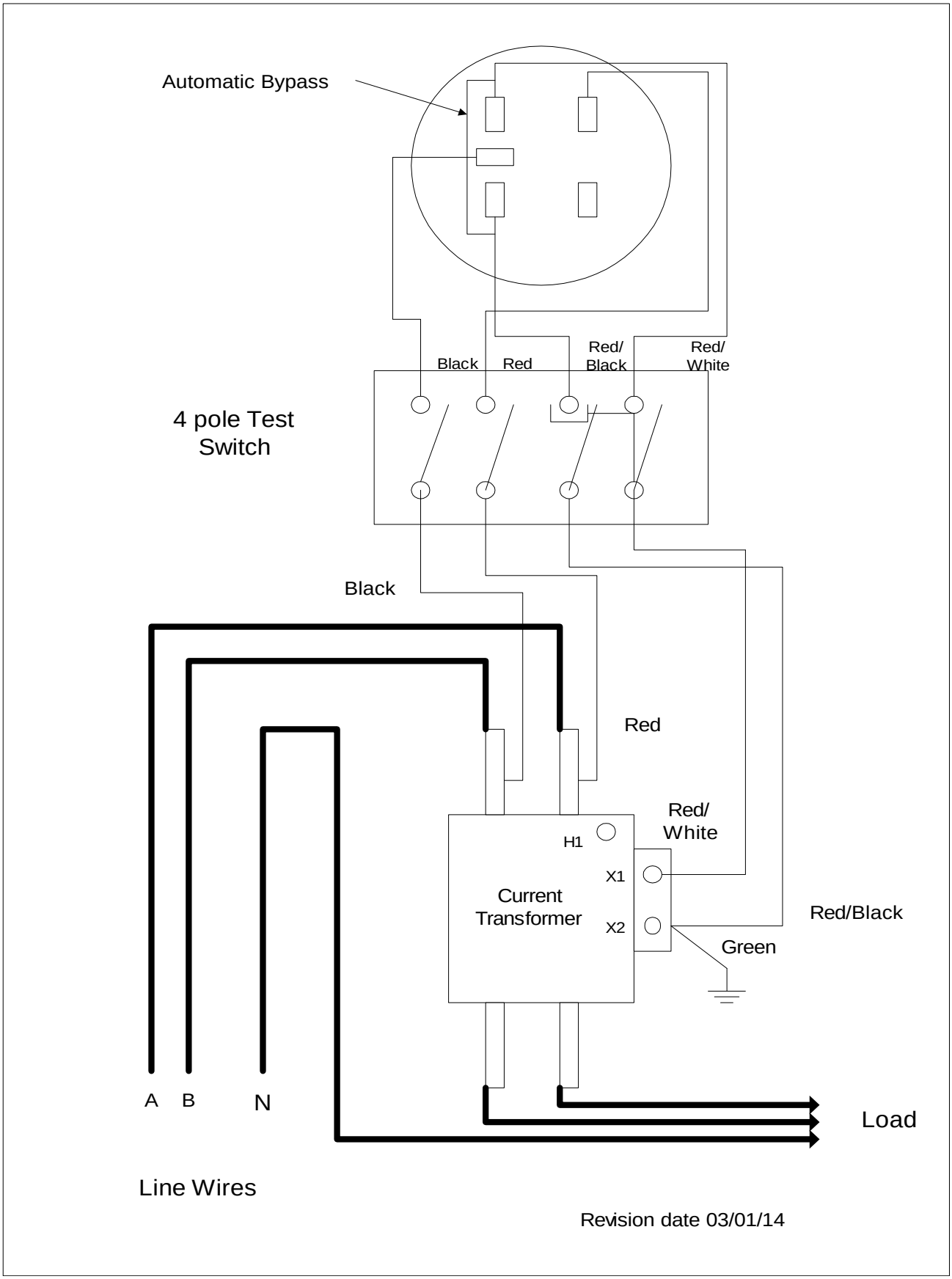
5. For WYE type installation, the neutral must enter the meter cabinet. In all situations the neutral will be terminated on an insulated neutral block centered at the bottom of the meter cabinet even when the neutral is continued past the meter cabinet to the customer. For any deviation from this, please contact the Crew Leader for the area.

Crew Leader: East of Yonge St., South of Eglinton Ave. - Clive Cobbett - 416-542-7883
Crew Leader: East of Yonge St., North of Eglinton Ave. - Les Lemieux - 416-542-8003
Crew Leader: Old city of Toronto, West of Yonge ST. & Old city of York - Fred Donofrio - 416-542-3281
Crew Leader: Old city of North York, West of Yonge St. & Old city of Etobicoke - Len Perrone - 416-542-3282

Revision Date:12/1/06

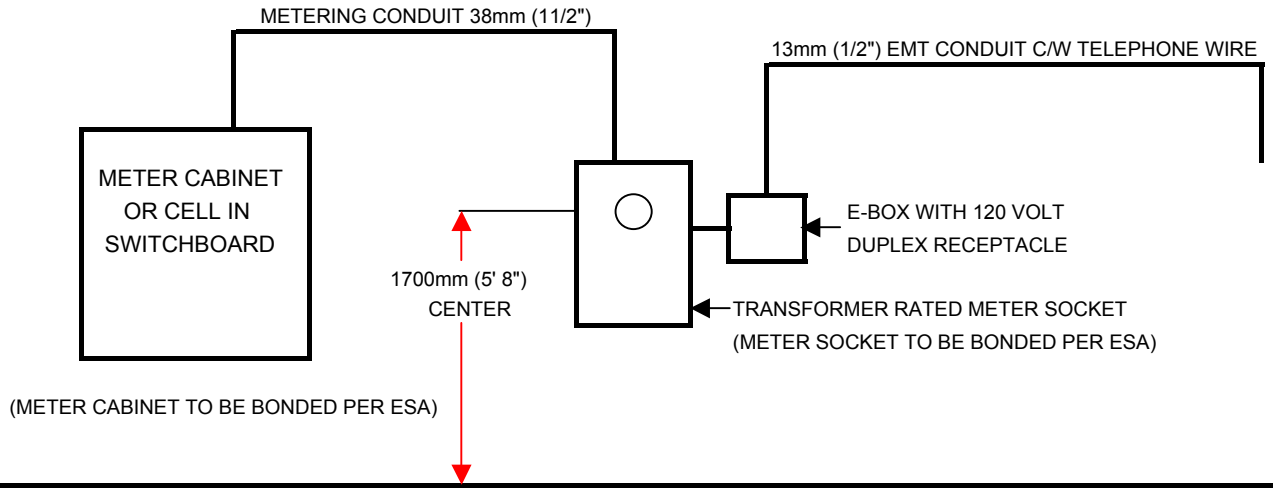
400 Amp Meter Socket Wiring Diagram

Daigram # 3



Revision date 03/01/14

METER REQUIREMENTS - NON TOTALIZED RIMS SERVICES ≥ 200 kW



Requirements

1. **Meter Socket** - must be transformer rated, no automatic bypass, provision for a 10 pole test panel, lockable cover to be bounded as per ESA, 1700mm (5' 8") to center of opening, socket can be located outdoors.

2. **Meter Conduit** - 38mm (11/2") conduit, no LB's permitted, continuous from the meter instrument transformers to the meter socket, maximum of three 90 degree bends, maximum conduit length is 30m (100').

3. **E-Box** - A 305mm x 305mm x 102mm (12" x 12" x 4") e-box with a hinged door directly adjacent [less than 102mm (4")] to the meter socket. The e-box will be connected to the socket with a 13mm (1/2") conduit. The connection to the meter socket is to be made at the top half of the meter socket opposite the meter socket jaws assembly. A 120 Volt duplex receptacle is to be located in this e-box. If possible, the 120 Volt supply should come from a UPS. The e-box must be lockable and when mounted outdoors, it must be weatherproof.

4. **Telephone Conduit** - A 13mm (1/2") EMT conduit, with bushings at both ends, complete with a 2-pair telephone cable, must extend from the e-box to where the telephone trunk lines terminate in the main telephone room. The telephone cable in the telephone room is to be clearly labelled "TORONTO HYDRO METERING". A RJ11 (4 pin) telephone jack is to be connected to the telephone cable in the e-box and left at the bottom of the e-box. See item 7.14 for further information. If the meter socket is located outdoors, the contractor will be required to install the conduit to a box that will allow the telephone provider to install an outdoor style phone jack.

5. **Meter Cabinet** - If a meter cabinet is to be utilized to house the instrument transformers, it must be 1220mm x 1220mm x 305mm (48" x 48" x 12"). The cabinet will be mounted at 2m (6'6") to the top +/- 78mm (3"). The entry points for the cables will be bottom right, bottom left or top left and top right. Entry and exit points must be within 153mm (6") from the corners. Please contact the District Crew Leader when the cabinet is mounted so that the Crew Leader can arrange installation of the metering transformers before the conductors are pulled in. The current transformers may be window type or bar type. The contractor is to pull the cables through the window type current transformers or, if bar type, make the connections to the current transformers bars. The meter conduit will extend from the cabinet to the meter socket.

6. **Meter Compartment in Switchboard** - Housing the metering transformers. The meter conduit is to extend continuously from this compartment to the meter socket. See item 2 above for meter conduit requirements.

toronto hydro

electric system

TORONTO HYDRO-ELECTRIC SYSTEM

METERING REQUIREMENTS
750 VOLTS OR LESS

FIRST EDITION: March 2003

REVISION #4: January 23, 2007

PREPARED BY: _____
ENGINEER, STANDARDS & MATERIALS SECTION

REVIEWED BY: _____
SUPERVISOR, STANDARDS & MATERIALS SECTION

CERTIFICATE OF APPROVAL THIS TECHNICAL SPECIFICATION MEETS THE SAFETY REQUIREMENTS OF SECTION 4 OF ONTARIO REGULATION 22/04	
R. Sironi, P. Eng. ROMANO SIRONI, P. Eng. MANAGER, POLICY & STANDARDS	Jan. 23, 2007 DATE

SECTION 6 - REFERENCE #6

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1. SCOPE

1.1 Toronto Hydro Requirements

This publication covers the requirements of Toronto Hydro, in addition to the requirements of the "Supply Authority" stated in the Ontario Electrical Safety Code, for service entrance, connection, and metering of electrical energy to Toronto Hydro customers for Permanent and Temporary Services.

1.2 Ontario Electrical Safety Code

Nothing contained in these Requirements shall prejudice or supersede any requirements of the Ontario Electrical Safety Code or affect regulations of existing building codes, unless specifically stated herein.

Some of these requirements identified by the latest edition of the Ontario Electrical Safety Code have been included for convenience and references purposes, even though they may be under the Electrical Safety Authority (ESA) jurisdiction.

Where reference is made to a particular Rule, then this should be taken also as a reference to an applicable Appendix.

2. PURPOSE

This document is intended to provide guidance to Toronto Hydro customers and their agents in the design, preparation of plans and construction of the proposed service installation with respect to revenue metering. The requirements apply to all new, rearranged or upgraded services, both permanent and temporary, and are intended to provide an efficient and safe supply of electrical energy with respect to revenue metering.

It shall be the responsibility of the customer to conform to the latest edition of the Toronto Hydro Requirements, the Toronto Hydro Conditions of Service and the Ontario Electrical Safety Code.

3. DEFINITIONS, PUBLICATIONS AND THE INTERNATIONALO SYSTEM OF UNITS

3.1 Definitions

3.1.1 In addition to the definitions stated in Section "0" of the Electrical Safety Code, the following meanings have been ascribed to the already defined or new terms.

Acceptable	Meets Toronto Hydro Requirements
Approval	Approval of drawings and customer's equipment is limited to Toronto Hydro's requirements and should not be construed as acceptance of liability due to faulty design and/or workmanships.
Compartment	A subdivision of a switchgear/switchboard unit.
Customer/ Consumer	The person or persons, firm, Corporation or their agents who request or use Toronto Hydro Services.
Service Entrance Equipment Sprinkler Proof Enclosure	An enclosure for indoor application so constructed or protected that water from sprinkler systems will not interfere with the successful operation of the enclosed Switchgear, excluding flooding.
Switchgear	A full height and full depth module of a switchgear or switchboard assembly. It is sometimes referred to as "cell", Unit, "cubicle" or "section".

3.2 Associated Publications and Standards

In addition to the applicable reference publications listed in the latest edition of the Ontario Electrical Safety Code, and all the applicable Toronto Hydro Standards the following publications shall also apply:

- Toronto Hydro Conditions of Service.
- Ontario Electrical Safety Code
- CSA Standard, C22.2 No. 4, Enclosed Switches
- CSA Standard, C22.2 No. 31, Switchgear Assemblies
- CSA Standard, C22.2 No. 115, Meter Mounting Devices
- EEMAC Standard for Switchgear Assemblies G8 – 2
- MEA (of Ontario) Guide to Municipal Standard Construction Part V-Metering and Service Entrance Equipment
- Electrical and Electronic Manufacturers Association for Revenue Metering Equipment in Switchgear Assemblies G10-1
- Ontario Building Code
- The Occupational Health and Safety Act and Regulations for Industrial Establishments
- CSA Standard, C235-83 – Preferred Voltage Levels for AC Systems 0 to 50,000 V.

NOTE: All publications shall be of the latest edition.

3.3 The International System of Units

SI units have been used in this publication for measurements and weights. The metric units have been rounded as close as possible to the previously used units. Equipment or materials not available in metric units shall be equal to or larger than the units specified in this publication. Equivalent substitution shall have prior approval from Toronto Hydro.

All drawings submitted by customers shall be in metric units.

4. PROCEDURE FOR SERVICE APPLICATION

4.1 Approval Routine

4.1.1 Initial Data Requirements

Application for supply of service shall include service address, load details, size and location of service and desired service date.

4.1.2 Drawings Required

Once the type of service has been determined, detailed drawings and specifications shall be submitted for review and acceptance. (see Section 4.2.)

4.1.3 Approvals Prior to Manufacture

Manufacture or work associated with the installation of equipment should start only after the design has been reviewed and accepted by Toronto Hydro.

4.2 Engineering Drawings and Specifications

4.2.1 Drawings Required for Acceptance

Fully dimensioned and scaled drawings submitted for Toronto Hydro's review and acceptance shall include but not be limited to the following list. The minimum number of copies of drawings required is indicated in brackets. The requirement may change without notice.

(a) Electrical room layout drawing showing the location of the electrical switchboard and all revenue metering (meter cabinets and or meter centres). (2)

(b) Single line distribution diagram. (2)

(c) Manufacturer's or shop drawings of the proposed switchboard, with a utility compartment detail drawing. (2)

(d) Meter center drawings (2)

Note: Additional drawings may be requested.

4.2.2 Drawing Revisions

If any drawings require revision Toronto Hydro will determine the number of copies of each drawing to be re-submitted for further review and acceptance.

4.3 Customer's Responsibilities - Service Change, Relocations and New Services

4.3.1 Meter Disconnection, Storage and Pick-up

When work is required on the customer's service entrance equipment, it shall be the responsibility of the customer or the customer's representative to:

(a) Notify Toronto Hydro of intention to disconnect a meter or metering equipment before removing any such equipment.

(b) Store the removed equipment in a safe place on site and immediately advise Toronto Hydro of this location for pick-up. Toronto Hydro will charge for lost or damaged meter (s) or metering equipment.

(c) Tag meter with the following information:
- date of removal
- address
- customer's name and telephone number

5. SERVICE ENTRANCE and ELECTRICAL ROOMS

5.1 General Requirements

5.1.1 Residential Outdoor Meters

Meters for new, changed or relocated residential services shall be mounted outdoors.

5.1.2 Non-Residential Outdoor Meters – 300 Volts or Less

Meters for other than residential services may be mounted outdoors in a weatherproof enclosure if an acceptable location is available.

5.2 Legislation and Specified Requirements

Where a service entrance electrical room contains a switchboard, the means of egress from such a hazardous room shall conform to the latest revisions of the Ontario Building Code and to the Ontario Occupational Health and Safety Act and Regulations for Industrial Establishments.

5.3 Exit Doors & Hardware

In addition to Section 3.4 of the Ontario Building Code on "Exits", the following shall be provided:

Exit Doors

(i) Exit doors shall open in the direction of exit travel and shall be equipped with panic type hardware.

(ii) No exit door shall open directly to the street or open space where there is danger of blockage from ice or snow and pedestrian or vehicular traffic. Such situations shall be discussed with Toronto Hydro to find solutions.

(iii) Exit doors shall be clearly identified.

5.4 600 Volt Delta and 347/600 Volt Y – In Electrical Rooms

600 V delta and 347/600 V Y services are NOT ACCEPTABLE in the same electrical room.

5.5 Fire Pump Services

1) Pending ESA approval; where the service cables for a fire pump service are 3/0 or less, the fire pump service shall be metered using an approved meter mounting device (meter socket).

2) Where the service cables for a fire pump service are larger than 3/0, the fire pump service shall be metered using a 1220mm x 1220mm x 305mm (48" x 48" 12") meter cabinet.

6. SWITCHBOARDS

6.1 Compartments

6.1.1 Compartment Isolation

The following items of equipment shall be isolated by means of separate compartments:

(a) Each service entrance switch or breaker (CSA Standard C22.2 No. 4).

(b) Each set of Toronto Hydro revenue metering instrument transformers.

NOTE: Barriers shall be installed between metered and unmetered sections.

6.2 Electrical Clearances

6.2.1 CSA Requirements

Where cable or bus connections are made to any component supplied or installed by Toronto Hydro (i.e. revenue metering current and voltage transformers), such connections shall be assumed to be bare conductor and full clearances shall be maintained in accordance with the following CSA table and the foot note:

Table 3 of CSA Standard C22.2 No. 31, M89

Nominal voltage Rating (v)	Minimum Spacing (mm)			
	Opposite Polarity		To ground	
	Through Air	Over Surface	Through Air	Over Surface
120 ac	12.5	19	12.5	19
240 ac	19	31	19	25
480 ac	22	44	22	34
600 ac	25	50	25	38

NOTE: Where a neutral is involved, the spacing between the neutral and other current-carrying parts may be based on the lower voltage that normally occurs between them. The spacing from neutral to grounded metal parts are to be the same as those between the current carrying conductors and grounded metal parts.

6.3 Equipment Access Doors

6.3.1 Equipment Working Space Requirement

Doors with vertical hinges shall be installed on the electrical cabinets and compartments containing live equipment where Toronto Hydro personnel will be required to work, such as service entrance switches, metering compartments, switchboard covers over main breakers and unmetered sections of the switchboards.

6.3.2 Provision for Sealing and Padlocking Equipment Access Doors

Hinged doors as described in 6.3.1 shall have provision for sealing. Where bolts are used for fastening they shall be of the captive knurled type with minimum 25mm diameter slotted heads.

Equipment access doors shall be equipped with padlock hasps measuring at least 30mm wide by 5mm thick capable of accepting a standard Toronto Hydro padlock with a 8mm shackle.

6.3.3 Equipment Access Door Openings

All hinged outer access doors shall open at least 135° and all hinged inner doors or screens shall open at least 90°.

7. TORONTO HYDRO REVENUE METERING EQUIPMENT

7.1 General Information

7.1.1 Scope of Supply

Toronto Hydro will supply all meters, instrument transformers and secondary wiring required for revenue metering. All revenue metering equipment shall remain the property of Toronto Hydro.

7.1.2 Customer's Instrumentation

(a) Customer's instrumentation shall be connected on the load side of the Toronto Hydro metering.

(b) Customer's relays, instruments or other devices shall not be connected in the metering circuit.

(c) Bottom connected A and P base type meters shall not be used as splitter boxes.

7.2 Metering Instrument Transformers

7.2.1 Instrument Transformer Data

Toronto Hydro will provide the manufacturer's name, type and rating of metering instrument transformers. Additional information, if required, will be available at the request of the customer.

7.2.2 Meter Enclosures

All metering instrument transformers and associated meters shall be installed in approved enclosures.

7.2.3 Metering Transformers on Load Side

Metering transformers shall be connected on the load side of the main fused switch or circuit breaker, excluding approved 400 amp single phase sockets.

7.2.4 Mounting Arrangements

Provision shall be made by the customer for mounting the metering transformers (See 7.4 and 7.5) including the supply and installation of all material for the primary connections to the current transformers.

7.3 Space Requirements for Meters without Instrument Transformers

7.3.1 Space for Meters Only

Minimum space requirements for meters are shown in Table I. All dimensions are in mm.

TABLE I

Meter Type	Phase	No. of Meters	Cabinet Size (min.)	Socket Type
Self-contained up to 200 A 600V	Poly or single phase	1	Not applicable	CSA/UL Approved
Transformer Rated Bottom Connected	Single or Poly	1 **or** 2	915w x 915h x 305d	Not Applicable
*RIMS Metering Transformer-rated Bottom Connected	3PH 3Wire	1	915w x 915h x 305d	TSU8; CT108; CTS800PW – See Diag. #4 for layout. See Note 1 below.
	3PH 4Wire	1	915w x 915h x 305d	TSU13; CT113; CTS130PW – See Diag. #4 for layout. See Note 1 below.
*Transformer rated Socket (S base)	3PH 3Wire	1	Not applicable	TSU8; CT108; CTS800PW
	3PH 4Wire	1	Not applicable	TSU13; CT113; CTS130PW
Transformer-rated Socket (S base) 201-400 Amp; 240 V. Residential/ Commercial	Single	1	Not applicable	JS4AB-300/5; CT4-TSB3 See Diag. #3 For Wiring

***Where metering transformers are located remotely (i.e. in switchboard).**

Note 1: Not applicable for totalized services.

7.3.2 Multiple Metering Points

Where there are multiple metering points requiring more than one set of metering transformers to be totalized, or where a recording instrument or special equipment is required, Toronto Hydro shall be consulted regarding cabinet size.

7.4 Space Requirements for Meters with Instrument Transformers

7.4.1 Space for Meters and Transformers

Minimum cabinet size for meters, instrument transformers and associated equipment is shown in Table II. All dimensions are in mm.

TABLE II

Voltage (V)	Phase	Wire	Main Switch Size	Cabinet Size (Min.)
120/240	1	3	>400 – 800 A.	1220w x 1220h x 305d
600* 120/208 347/600 Y	3 3	3 4	>200 – 800 A.	1220w x 1220h x 305d
240/416*	3	4	>200 - 800 A.	1220w x 1220h x 305d

*For existing services only.

Note: (1) A larger cabinet or 2 separate cabinets may be required:
(a) Where cable size exceeds the main switch capacity.
(b) Where more than 2-500 kcmil CU or 2-750 kcmil AL are used.
(c) Where meter cables do not enter the meter cabinet in a location to permit efficient use of space.

(2) Meter cables in a meter cabinet will be located so that the most efficient use of the space is accomplished. Diagram #2 shows the preferred meter cabinet area that will be utilized for the installation of meter (s) and accompanying test switches. The cables and instrument transformers must not encroach on the metering area shown in the diagram.

(3) Once the meter cabinet has been installed, but before the conduit/corflex cable has been installed, the customer/electrician **must** contact the Toronto Hydro Meter Services Department Crew Leader (see diagram #2 for phone numbers) to arrange for metering inspection.

(4) Where main switch capacity exceeds 800A, a switchboard is required with a separate revenue metering compartment. See Section 7.11 for details.

(5) A neutral wire is required for metering 120/208 and 347/600 volt services. The customer shall provide and install a full size neutral cable (white) from the neutral bus in the main switch or splitter to the meter cabinet. The neutral is to terminate at an insulated neutral block. See diagram #2.

7.5 Meter Cabinets

7.5.1 General

(a) Meter cabinets containing Toronto Hydro equipment shall not be used as splitter boxes.

(b) Meter cabinets, installed outdoors or where sprinklers are used, shall be weatherproof type.

(c) Meter cabinets installed outdoors shall be equipped with door stops.

7.5.2 Material

All meter cabinets shall be made of sheet steel, #16 MSG minimum.

7.5.3 Doors

Meter cabinets for indoor and outdoor installation shall be equipped with vertically hinged doors. Cabinets 915mm x 915mm x 305mm or larger shall have double doors opening at the center.

7.5.4 Locking and Sealing

Meter cabinets for indoor and outdoor installation shall be equipped with door latch and handle (or combination latch-handle) with provision for a Toronto Hydro padlock and seal.

7.5.5 Mounting Panel (Back Plate)

Meter cabinets shall be equipped with removable #16 MSG min. sheet metal interior panels. The panel shall be 75mm narrower and 75mm shorter than the meter cabinet and mounted with a clearance of 15mm behind it.

7.6 Mounting Height for Meter Cabinets

7.6.1 Minimum – Maximum Heights

Minimum distance from floor to base of cabinets shall be 600mm.
Maximum distance from floor to top of cabinets shall be 2000mm.

Note: Any deviation from these dimensions shall require Toronto Hydro approval

7.7 Freedom from Vibration

7.7.1 Mounting

Meter cabinets and panels shall be mounted so as to be free from vibration and mechanical shock.

7.8 Meter Cables

7.8.1 Cable Length, Material, Type & Size

(a) Where instrument transformers are installed in a meter cabinet the minimum length of each meter cable, both line and load side, shall be 1200mm.

(b) Mineral insulated solid or hard drawn wire conductors are not acceptable for meter cables.

(c) Line and load meter cables shall be identical in type, number of conductors and wire size.

(d) Meter cables shall be on the load side of the main switch or breaker.

7.8.2 Entry Points

Line and load entry points shall be located so that meters and/or instrument transformers can be mounted to permit efficient use of space provided. [See 7.4.1 note 2 and Diagram #2].

7.8.3 Primary Connections in Meter Cabinet

The customer/electrician shall make all primary connections on the meter cables in the meter cabinet:

a) The customer/electrician is to contact the Toronto Hydro Meter Services Department Crew Leader (see diagram #2 for phone number) to arrange installation of the metering current transformers.

b) Once the metering transformers have been installed, the customer/electrician is to either insert the primary meter cables through the window type current transformers or make compression sleeve connection on the primary meter cables. Should bar type metering current transformers be used, then the customer/ electrician shall make compression type terminal lug connections to the bar type metering current transformers. Mechanical connections are not acceptable.

c) The customer/electrician shall supply all compression sleeves and or compression lugs.

d) Toronto Hydro will wrap all the connections at the current transformers.

NOTE: Any deviation from these dimensions shall require Toronto Hydro approval.

7.9 Socket-type Meter Mounting Devices – 200 Amps or Less

7.9.1 Customer Supplied Devices

(a) Meter mounting devices shall be provided and maintained by the customer, be of a type approved by Toronto Hydro and conform to the latest edition of CSA Standards.

(b) Round and shallow square meter mounting devices are not permitted.

(c) Meter mounting devices shall have a supplied metal sealing ring.

(d) Automatic bypass devices are not permitted.

(e) Meter mounting devices installed indoors shall be on the load side of the service switch.

(f) Meters for new and upgraded residential services shall be mounted outdoors in a location approved by Toronto Hydro.

7.9.2 Approved-Type Devices

(a) Meter mounting devices are required for all services up to 200A. The requirements are indicated below and shown in Diagram #1.

120/240V	1 Phase	3 Wire	4-jaw socket
120/208V	1 Phase	3 Wire	5-jaw socket
120/208V	3 Phase	4 Wire	7-jaw socket
347/600V	3 Phase	4 Wire	7-jaw socket
600V*	3 Phase	3 Wire	5-jaw socket

* (Existing Services Only)

(b) Dual socket meter mounting devices are not permitted.

(c) Ringless meter mounting devices are not permitted.

7.9.3 Rating

(a) Approved meter mounting devices shall have a minimum rating of 100A, and be rated no less than the service capacity. For example, a 125A service requires a 200A meter-mounting device.

(b) All new and upgraded residential services rated up to 200A shall utilize an approved meter mounting device.

7.9.4 Mounting and Space Requirements

(a) Meter mounting devices shall be installed in an acceptable manner and location. They must be mounted level in the horizontal and vertical planes (see Diagram #1 for terminal arrangements) at heights indicated below:

Outdoors – The centerline of the meter shall be 1700mm ± 100mm.

Indoors – The centerline of the meter shall be approximately 1700mm but in no case shall it be more than 1800mm or less than 600mm.

(b) A clear space of 400mm w x 600 mm h shall be provided for each meter mounting device.

7.9.5 Energization Prior to Installation of Meter

When the service is to be energized prior to the installation of the meter, acceptable temporary jumper bars may be used in the meter mounting devices. Should the meter jaws be found to be damaged by improper use of jumpers, the customer shall replace the meter socket.

7.10 Service Identification

7.10.1 Marking and Labeling of Service Boxes and Equipment

(i) The customer shall permanently and legibly identify each metered service with respect to its specific address which shall include the store or apartment number, where applicable.

(ii) The identification shall be applied to all service switches and circuit breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to their service switches or circuit breakers.

(iii) Non-permanent markers or paper labels are not acceptable on equipment which requires identification.

7.11 Metering Requirements for Enclosed Switchboards

7.11.1 Separate Compartment

A separate compartment with a vertically hinged access door having provision for sealing and locking shall be provided for each set of metering instrument transformers for the exclusive use of Toronto Hydro. See Section 6.3 for sealing and locking requirements.

7.11.2 Mounting Hardware

Mounting bolts or nuts shall be installed in a manner which will permit complete installation and/or removal of the instrument transformers from within the compartment in which they are installed. Fixed mounting nuts or bolts shall be required for this purpose.

7.11.3 Installation by Manufacturer/Customer

(a) When the switchboard drawings have been approved, the metering instrument transformers will be delivered upon request to the switchboard manufacturer for installation in the switchboard. The current transformers shall be installed with the polarity marks on the line side. The type and rating of instrument transformers to be supplied shall be determined by Toronto Hydro.

(b) Metering instrument transformers delivered to the site by Toronto Hydro are to be installed in the switchboard by the customer/manufacturer.

(c) All hardware, bus work and/or cable required for primary connections to metering current transformers shall be provided by the customer or the switchboard manufacturer.

(d) The customer and or manufacturer shall not disassemble and/or change in any manner the Toronto Hydro equipment sent to them.

7.11.4 Window Type Current Transformers

(a) Where window-type current transformers are to be installed, the bus shall be sectionalized. The removable bus links through the current transformers shall be bolted in the vertical bus section directly above and below the current transformers. Where three window-type current transformers are used, they shall be mounted in a staggered arrangement.

(b) Where window current transformers are used and the switchboard bus is larger than the window opening, the customer or switchboard manufacturer shall modify the bus to accommodate the current transformers.

(c) The instrument transformers will be supplied by and will remain the property of Toronto Hydro.

7.11.5 Voltage Transformers

Where required provision shall be made for the installation of voltage transformers on a #16 MSG steel panel in an accessible location in the instrument transformer compartment. This panel must not obstruct access to the current transformers or the removable bus links through the current transformers. This panel is to be a minimum of 140 mm from the front of the instrument transformer compartment.

The voltage transformers are to be installed in the instrument transformer compartment by the switchboard manufacturer and/or electrician on site.

7.11.6 Neutral Bus Tap

A readily accessible continuous neutral copper bus of 25mm x 3mm or equivalent (#6 copper white TW75 wire), with three 10-24 tapped holes, shall be provided in each instrument transformer compartment for all 3 phase 4 wire services. If the main neutral bus passes through a metering instrument transformer compartment, the bus shall be provided with three 10-24 tapped holes.

7.11.7 Grounding Stud

A readily accessible grounding stud with a connector suitable for a #10 copper wire or a ground bar provided with three 10-24 tapped hole shall be provided in each instrument transformer compartment. The grounding facility in the compartment shall be connected directly to the switchboard ground bus.

7.11.8 Compartment Sizes

Minimum metering transformer compartment size in mm are given in Table III.

TABLE III

METERING INSTRUMENT TRANSFORMER COMPARTMENT – MINIMUM SIZES

Metering Transformers and Compartments						
Voltage (Volts)	Phase	Wire	Service Size (Amperes)	Compartment Size	Number of Metering Transformers (Provision for)	
					Current	Voltage
240/120 208/120 N/W	1 3	3 3	Up to 800	A	1 or 2	0
			Over 800 Up to 4000	B		
208/120 416/240 600/347	3	4	Up to 800	A	3	3
			Over 800 Up to 4000	B	3	
600*	3	3	Up to 800	A	2	2
			Over 800 Up to 4000	B	2	
Voltages up to 600	(*) 3 3	(*) 3 4	Over 4000	C	2 3	2 3

* For existing services only.

COMPARTMENT SIZES [width x height x depth (from CT mounting plate)]

A - 762mm x 762mm x 210mm (30” x 30” x 8.25”)
B - 965mm x 762mm x 324mm (38” x 30” x 12.75”)
C - 965mm x 914mm x 381mm (38” x 36” x 15”)

7.12 Meter Cabinets and Conduit Requirements

7.12.1 Location of Meter Cabinet

Meter cabinets associated with revenue metering transformers mounted in a switchboard shall be located in an approved location close to the switchboard.

7.12.2 Conduit and Metering Compartment

A separate conduit (to be continuous within the switchboard) is required from each revenue metering compartment to the meter cabinet. The meter conduit is to terminate at the front right or left corner of the revenue metering compartment and be unobstructed.

7.12.3 Conduit Length and Size

The maximum length of conduit shall be no longer than 30m. The customer shall supply and install a conduit of a nominal diameter of not less than 38 mm.

7.12.4 Conduit Fittings and Covers

(a) The number of bends shall be kept to a minimum, but in no case shall there be more than three 90 degree bends.

(b) The metering conduit run within the switchboard and between the switchboard and the meter cabinet shall not have fittings with removable covers. Pull boxes and or 'LBs" are not permitted.

(c) The 38mm metering conduit between the revenue metering instrument transformer compartment in the switchboard and the meter cabinet is to be rigid steel, EMT or PVC. Flexible conduit is not permitted.

7.12.5 Pull Line In Conduit Run

The customer shall install a strong nylon or polyrope pull line in the conduit between each revenue metering transformer compartment and the meter cabinet. An excess of 1500mm loop shall be left at each end.

7.12.6 Connection of Meter Wires

Under no circumstances will Toronto Hydro install and connect meter wires unless the service is de-energized.

7.12.7 Meter Cabinet Bonding

The meter cabinet is to be bonded to the system ground in accordance with the Ontario Electrical Safety Code.

7.13 Meter Centres

7.13.1 Provision for Sealing

The customer shall make provision for the installation of Toronto Hydro seals on the following:

(a) removable covers and doors which provide access to unmetered circuits.

(b) handles of all circuit breakers in the "OFF" position.

7.13.2 Provision for Padlocking

Circuit breakers or fused switches protecting a meter socket shall have provision for padlocking in the open position.

7.13.3 Approved Meter Socket Assemblies

Only meter socket assemblies listed in Section 7.9.2 shall be used in Meter Centres. The meter sockets shall be properly aligned and mounted on a rigid base to prevent subsequent misalignment.

7.13.4 Protection of Meter Mounting Devices

Each meter-mounting device shall be protected by a rated circuit breaker having adequate short circuit interruption capacity. The circuit breaker shall be connected ahead of the meter-mounting device commonly known as "cold" metering.

7.13.5 Identification of Socket and Cover

Each removable meter socket and circuit breaker cover shall be identified by a permanent and unique mark (number, letter, etc.) so that it cannot be interchanged with other similar covers. The same identification mark shall appear on the frame of the meter centre at the compartment where the cover belongs and shall be clearly visible when the covers and meters are in place. This identification mark need not be the number of the suite metered, thus making it feasible to have the identification marks applied during manufacture of the meter centre.

7.13.6 Identification of Individual Service

Each circuit breaker required for an individual service shall have a permanent customer identification plate (metal or engraved plastic) which cannot be erased or obscured by paint. The circuit breakers must easily be recognized.

7.13.7 Positioning of Meters

(a) The centerline of the lowest meters shall not be less than 600mm from the finished floor level. The centerline of the upper meters shall not exceed 1800mm from the finished floor level.

(b) The minimum horizontal distance between the adjacent meter and sockets shall be 152mm rim-to-rim.

(c) The minimum vertical distance rim-to-rim between the adjacent meter socket openings shall be as follows:

(i) 76mm: for 100A, 4 or 5 jaw.
(ii) 152mm: for 100A, 7 jaw.
(iii) 152mm: for 200A, 4, 5 and 7 jaw.

7.13.8 Neutral for Meters

Where a neutral is required for metering, the meter mounting device shall have a pre-wired neutral connection (see Diagram #1). This neutral connection shall be ungrounded. The connection to the 5th or 7th terminal, if not made directly to the distribution neutral bus, shall be not less than #12 AWG copper or equivalent. Where a connection is to be made between aluminum and copper conductors, a proper bi-metallic connector shall be used.

7.13.9 Barrier for Meters

Each meter socket shall be separated from others by a suitable barrier.

7.13.10 Sealing Ring

Each meter socket shall be equipped with a metal sealing ring.

7.14 Remote Metering (RIMS) – Services 200 kW and Greater

The customer is to provide and install the following:

(a) 1-13mm (1/2”) EMT or PVC conduit complete with bushings at both ends between the revenue metering cabinet/ebox and the telephone room (punch-board). The 13mm (1/2”) conduit is to terminate at the top right corner of the meter cabinet/ebox.

A 2 pair (4 conductors) telephone cable is to be installed in the 13 mm (1/2") conduit. A RJ11 (4 pin) telephone jack is also to be provided and installed on the telephone cable in the meter cabinet/ebox. The telephone jack is to be left at the bottom of the meter cabinet/ebox with enough telephone cable to allow mounting the jack anywhere in the cabinet/ebox. The telephone cable terminating in the telephone room is to be clearly labeled "TORONTO HYDRO METERING".

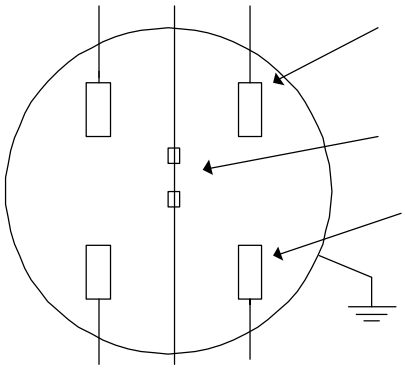
(b) Toronto Hydro will arrange to have the telephone line activated. Customer owned telephone lines or customer shared telephone lines are not acceptable.

(c) 1 – 120 Volt duplex receptacle, to be located at the bottom right corner inside the meter cabinet/ebox. The receptacle is to be connected to an uninterruptible power supply (UPS) if available.

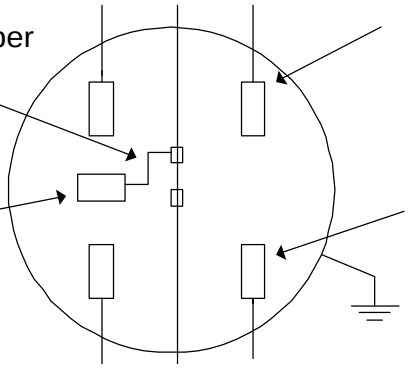
(d) The name and phone number of an on site contact person.

Diagram # 1

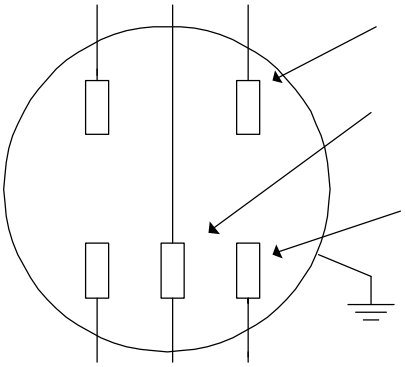
Terminal Arrangements for Meter Mounting Devices



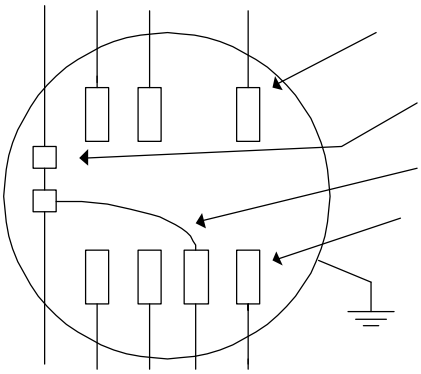
120/240
Single Phase



120/208, Two Phase plus Neutral



600 Volt
3 Phase, 3 Wire

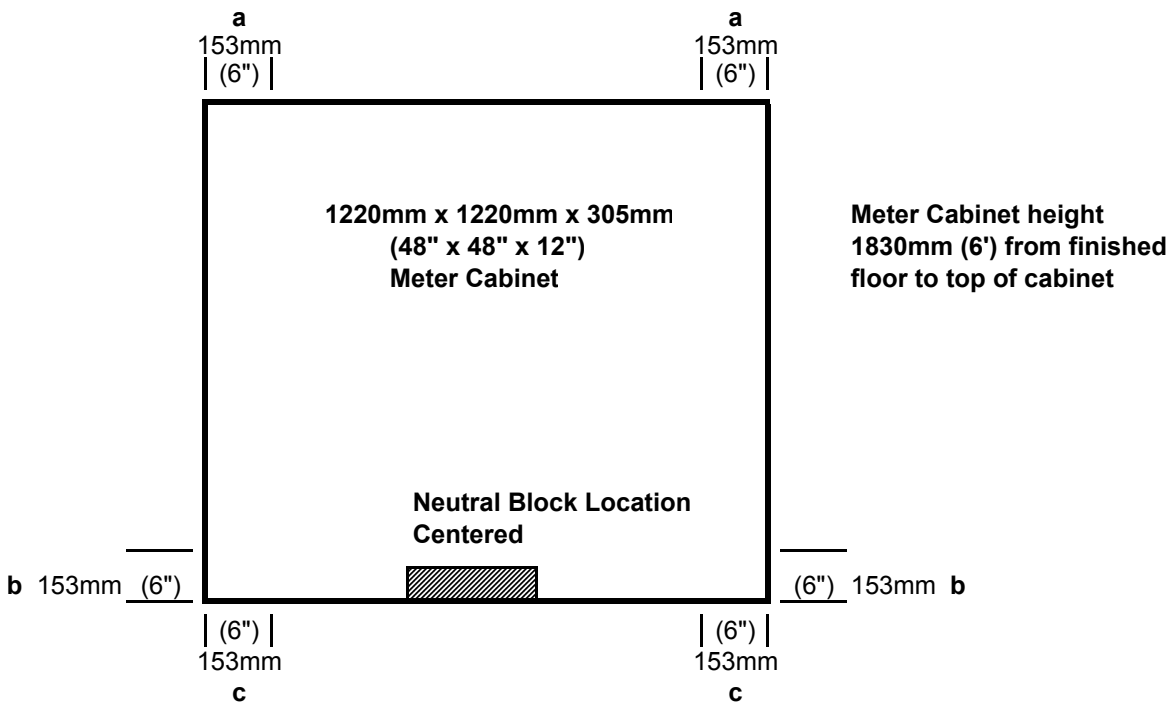


3 Phase 4 Wire

Revison Date: 03/01/14

Cabinet Layout for CTs/PTs Located Within the Meter Cabinet

Diagram # 2



1. Entry and exit points must be at points **a to a, b to b or c to c**. Any other conditions require approval from Meter Crew Leader from the district you are working within.

2. The electrican will inform the Meter Crew Leader once the meter cabinet is mounted but before the conductors are pulled in. The Crew Leader will the arrange for the installation of the metering equipment. All new jobs will utilize window type current transformers. The current transformers must be installed prior to the electrican pulling in the conductors.

3. The electrican will be responsible for pullling the cables through the appropriate current transformers and ensuring that phases correspond in cases of multiple conductors per phase. The electrican will lock off the switch until the metering installation is complete and all conditions are met with Toronto Hydro Electric System and ESA.

4. The electrican will be responsible for any splices, sleeve or lugs in the meter cabinet once the cable is pulled through the current transformers. Toronto Hydro will **not** provide any material for splices. Compression sleeves are recommended. All spice material must pass inspection by ESA.

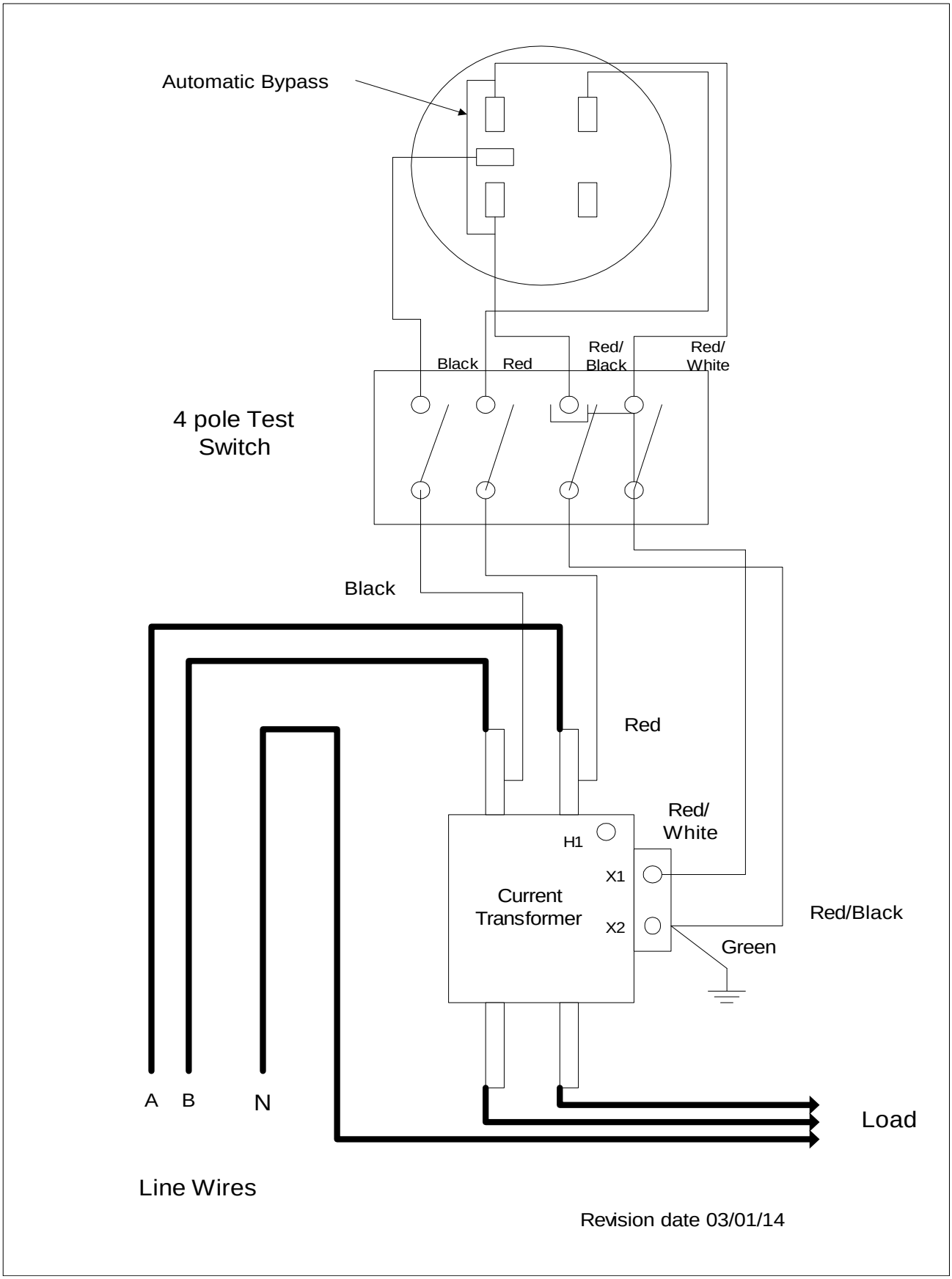
5. For WYE type installation, the neutral must enter the meter cabinet. In all situations the neutral will be terminated on an insulated neutral block centered at the bottom of the meter cabinet even when the neutral is continued past the meter cabinet to the customer. For any deviation from this, please contact the Crew Leader for the area.

Crew Leader: East of Yonge St., South of Eglinton Ave. - Clive Cobbett - 416-542-7883
Crew Leader: East of Yonge St., North of Eglinton Ave. - Les Lemieux - 416-542-8003
Crew Leader: Old city of Toronto, West of Yonge ST. & Old city of York - Fred Donofrio - 416-542-3281
Crew Leader: Old city of North York, West of Yonge St. & Old city of Etobicoke - Len Perrone - 416-542-3282

Revision Date:12/1/06

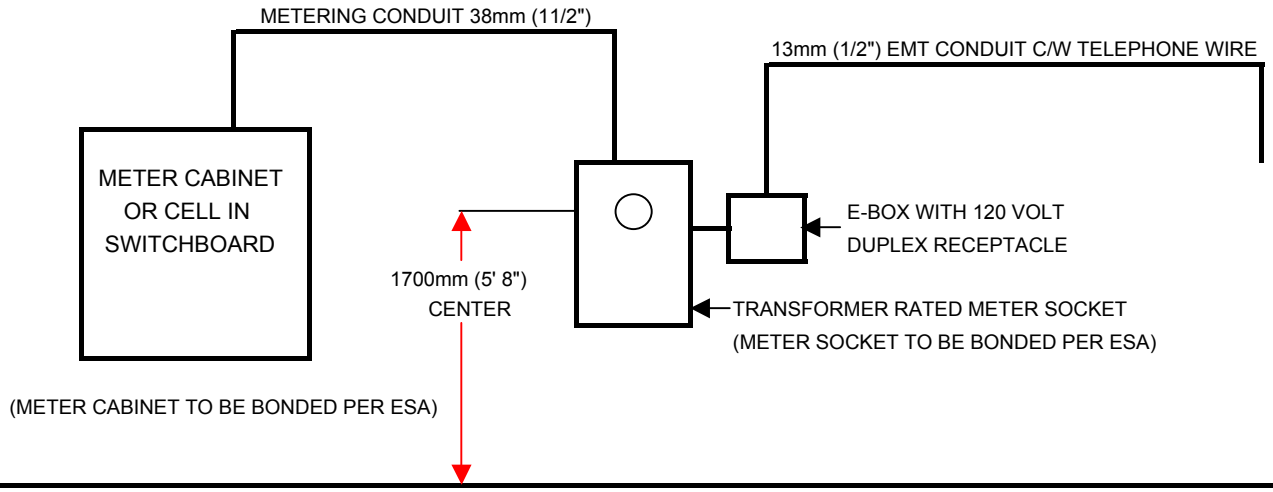
400 Amp Meter Socket Wiring Diagram

Daigram # 3



Revision date 03/01/14

METER REQUIREMENTS - NON TOTALIZED RIMS SERVICES ≥ 200 kW



Requirements

1. **Meter Socket** - must be transformer rated, no automatic bypass, provision for a 10 pole test panel, lockable cover to be bounded as per ESA, 1700mm (5' 8") to center of opening, socket can be located outdoors.

2. **Meter Conduit** - 38mm (11/2") conduit, no LB's permitted, continuous from the meter instrument transformers to the meter socket, maximum of three 90 degree bends, maximum conduit length is 30m (100').

3. **E-Box** - A 305mm x 305mm x 102mm (12" x 12" x 4") e-box with a hinged door directly adjacent [less than 102mm (4")] to the meter socket. The e-box will be connected to the socket with a 13mm (1/2") conduit. The connection to the meter socket is to be made at the top half of the meter socket opposite the meter socket jaws assembly. A 120 Volt duplex receptacle is to be located in this e-box. If possible, the 120 Volt supply should come from a UPS. The e-box must be lockable and when mounted outdoors, it must be weatherproof.

4. **Telephone Conduit** - A 13mm (1/2") EMT conduit, with bushings at both ends, complete with a 2-pair telephone cable, must extend from the e-box to where the telephone trunk lines terminate in the main telephone room. The telephone cable in the telephone room is to be clearly labelled "TORONTO HYDRO METERING". A RJ11 (4 pin) telephone jack is to be connected to the telephone cable in the e-box and left at the bottom of the e-box. See item 7.14 for further information. If the meter socket is located outdoors, the contractor will be required to install the conduit to a box that will allow the telephone provider to install an outdoor style phone jack.

5. **Meter Cabinet** - If a meter cabinet is to be utilized to house the instrument transformers, it must be 1220mm x 1220mm x 305mm (48" x 48" x 12"). The cabinet will be mounted at 2m (6'6") to the top +/- 78mm (3"). The entry points for the cables will be bottom right, bottom left or top left and top right. Entry and exit points must be within 153mm (6") from the corners. Please contact the District Crew Leader when the cabinet is mounted so that the Crew Leader can arrange installation of the metering transformers before the conductors are pulled in. The current transformers may be window type or bar type. The contractor is to pull the cables through the window type current transformers or, if bar type, make the connections to the current transformers bars. The meter conduit will extend from the cabinet to the meter socket.

6. **Meter Compartment in Switchboard** - Housing the metering transformers. The meter conduit is to extend continuously from this compartment to the meter socket. See item 2 above for meter conduit requirements.

toronto hydro
electric system

TORONTO HYDRO
METERING REQUIREMENTS
for
13.8kV & 27.6kV CUSTOMER-OWNED SUBSTATIONS

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PREPARED BY: _____
ENGINEER, STANDARDS & MATERIALS

REVIEWED BY: _____
SUPERVISOR, STANDARDS & MATERIALS

CERTIFICATE OF APPROVAL **THIS TECHNICAL SPECIFICATION MEETS THE SAFETY REQUIREMENTS OF SECTION 4 OF ONTARIO REGULATION 22/04**	
R. Sironi **ROMANO SIRONI, P.Eng.** **MANAGER, POLICY & STANDARDS**	Oct. 10, 2006 **DATE**

SECTION 6 - REFERENCE #7

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1.0 SCOPE

1.1 Toronto Hydro Requirements

This publication covers the metering requirements for Toronto Hydro customers. They apply to both permanent and temporary services. These requirements are in addition to those of the "Supply Authority" stated in the Ontario Electrical Safety Code for service entrance, connection, and metering of electrical energy.

1.2 Ontario Electrical Safety Code

Nothing contained in these Requirements shall prejudice or supersede any requirements of the Ontario Electrical Safety Code or affect regulations of existing building codes, unless specifically stated herein.

Some requirements identified by the latest edition of the Ontario Electrical Safety Code have been included for convenience and reference purposes, even though they may be under the Electrical Safety Authority (ESA) jurisdiction.

Where reference is made to a particular Rule, then this should be taken also as a reference to the applicable Diagram.

2.0 PURPOSE

This document is intended to provide guidance to Toronto Hydro customers and their agents in the design, preparation of plans, and construction of the proposed service installation with respect to revenue metering. These requirements apply to all new, rearranged or upgraded services, both permanent and temporary, and are intended to provide an efficient and safe supply of electrical energy with respect to revenue metering.

It shall be the responsibility of the customer to conform to the latest edition of the Toronto Hydro Requirements, the Toronto Hydro Conditions of Service, and the Ontario Electrical Safety Code.

3.0 DEFINITIONS AND THE INTERNATIONAL SYSTEM OF UNITS

3.1 Definitions

In addition to the definitions stated in Section "O" of the Electrical Safety Code, the following meanings have been ascribed to the terms defined below.

Acceptable	Meets Toronto Hydro requirements.
Accessible	The equipment is not guarded by locked doors, elevation or other effective means.

Approval	Approval of drawings and customers' equipment is limited to the approval of Toronto Hydro's metering requirements and does not construe acceptance of liability arising from substandard design or workmanship.
Compartment	A subdivision of a unit.
Customer	Means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions
Customer-owned Substation	A customer-owned civil structure accommodating customer-owned electrical equipment connected to Toronto Hydro 13.8kV or 27.6kV system.
Exit	A path of travel, which leads from a floor area to a separate building, an open public thoroughfare or an exterior open space, which is protected from fire exposure from the building and has access to an open public thoroughfare.
High Voltage	In this document, high voltage means 13.8kV or 27.6kV.
Means of Egress	A means of egress is a continuous path of travel provided for the escape of persons from any point in a building or a contained open space (i.e. Substation) to an open public thoroughfare. The means of egress includes the exit and access to the exit.
MSG	Means Manufacturer's Standard Gauge for uncoated steel.
Readily Accessible	Capable of being reached quickly for operation, removal or inspection, without requiring climbing over or removing of obstacles or resorting to the use of portable ladders, chairs, etc.
Sprinkler-Proof Enclosure	An enclosure for indoor application so constructed or protected that water from sprinkler systems will not interfere with the successful operation of the enclosed switchgear, excluding flooding.
Switchboard	Means a switchgear assembly that consists of one or more panels upon which switching control, meters and protective regulatory equipment are mounted and in which the panel or panel supports may also carry the main switching and interrupting devices together with their connections.
Unit (Switchgear)	A full height and full depth module of a switchgear assembly. It is sometimes referred to as "cell", "cubicle" "section" or "enclosure".
Primary Metering	Revenue metering over 750 volts.

3.2 The International System of Units

Measurements and weights used in this publication are expressed in SI units. The metric units have been rounded as close as possible to the previously used units. Equipment or materials not available in metric units shall be equal to or larger than the units specified in this publication. Equivalent measurements will be accepted if equipment or materials are not manufactured in metric units.

4.0 METERING CHARGES

Metering charges will apply to all 13.8 and 27.6kV primary metering. Costs will be determined by Toronto Hydro.

5.0 PROCEDURE FOR OBTAINING TORONTO HYDRO APPROVAL

Following acceptance of a Customer's application for a primary metered service or a proposal to modify an existing primary metered service, the following procedure shall apply.

5.1 Drawings

The customer shall submit to Toronto Hydro for approval the drawings listed in Section 6.

5.2 Additional Drawings

If the drawings or information do not meet the Toronto Hydro requirements or are not sufficiently clear, then revised or additional drawings and information must be submitted when requested by Toronto Hydro.

5.3 Manufacture of Equipment – Drawing Approval

Manufacture of equipment should not start until all drawings and information have been approved. This will avoid costly changes to completed equipment. Final revision of all drawings must be delivered to Toronto Hydro as least four weeks prior to the delivery of the switchgear to the service site.

5.4 Inspection of Equipment Prior to Shipment

Toronto Hydro reserves the right to inspect the completed equipment at the manufacturer's plant, prior to shipment.

5.5 Compliance with Requirements

When the installation of the equipment has been completed, Toronto Hydro will inspect the equipment to ensure it complies with these requirements.

5.6 Metering Equipment Delivery

Metering equipment delivery may take up to 16 weeks after the switchgear drawings have been approved.

6.0 ENGINEERING DRAWINGS AND SPECIFICATIONS

6.1 Drawings Required for Acceptance

Fully dimensioned and scaled drawings submitted for Toronto Hydro's review and acceptance shall include but not be limited to those listed below. The minimum number of drawings required is indicated in brackets. The published requirements may change without notice.

(a) Electrical substation layout drawing showing the location of the electrical switchgear and all revenue metering (meter cabinets). (2)

(b) Single line distribution diagram. (2)

(c) Manufacturer's or shop drawings of the proposed switchgear with a utility compartment detail drawing. (2).

Note: Additional drawings may be requested.

6.2 DRAWING REVISIONS

If any drawings require revision, Toronto Hydro will determine the number of copies of each drawing to be re-submitted for further review and acceptance.

7.0 SUBSTATION REQUIREMENTS

7.1 Exits and Doors

7.1.1 Miscellaneous Requirements

Two exits, one at each opposite end of the substation, are required. The exit doors shall open in the direction of exit travel and shall be equipped with panic type hardware. The doors shall be fitted with a keyed cylinder lock and handle on the opposite side of the door from the bar, all to be acceptable to Toronto Hydro.

8. 0 SAFE WORKING SPACE

Safe working space in vicinity of service entrance equipment including metering shall be in accordance with the Electrical Safety Code Rule 2-308 (Working Space About Electrical Equipment) and shall include the following:

8.1 Minimum Space Requirement

A minimum of 1.5 metres shall be provided in front of all doors giving access to switchgear components and where Toronto Hydro is required to work.

8.2 Side or Rear Access Panels

Side or rear access panels are not acceptable for metering transformer installations.

8.3 Aisle Space

A clear passageway at least 0.9 metres wide and 2.2 metres high shall be maintained as an exit route from all service entrance equipment. This headroom must also be maintained in the working space in the vicinity of the service entrance equipment.

8.4 Blocking of Exit Route

Where the compartment hinged doors or draw-out components would block the exit route, then a clear minimum space of 0.6 metres must be maintained from the edge of the access door or components in their fully open position.

8.5 Illumination of Equipment

Adequate illumination shall be provided in accordance with Electrical Safety Code Rule 2-314 (Illumination of Equipment) to allow for proper operation and maintenance of electrical equipment. The lighting shall be controlled by wall switches located at the entrances to these areas.

8.6 Accessibility for Maintenance

Passageways and working space around electrical equipment shall not be used for storage and shall be kept clear of obstructions and so arranged as to give authorized persons ready access to all parts requiring attention in accordance with Electrical Safety Code Rule 2-312 (Accessibility for Maintenance).

8.7 Access to Substation by Toronto Hydro

Immediate access to the substation must be provided on a 24-hour basis for Toronto Hydro personnel. A door, equipped with a Toronto Hydro lock, giving direct access to the substation from the outside shall be provided where practicable. Alternatively, the doors along the route leading to the substation must be equipped with Toronto Hydro locks.

If Toronto Hydro locks are not practical, the customer shall provide Toronto Hydro the appropriate access keys or magnetic cards to enable entry from street to the substation.

9.0 EQUIPMENT REQUIREMENTS

9.1 Enclosures

9.1.1 Sheet Steel Enclosures

All enclosures including barriers between compartments containing high voltage components shall be of sheet steel not less than #11 MSG and all other covers, barriers, panels and doors shall not be less than #14 MSG.

9.1.2 Enclosure Interiors

Interiors of enclosures shall be finished in white enamel.

9.1.3 Mimic Bus

A mimic bus on front door of switchgear compartment with no rear access shall indicate the internal electrical arrangement of equipment in each compartment. The mimic bus shall be securely fastened to the panel. For switchgear with rear access doors, all components, both front and rear, shall be marked and labeled similarly.

9.1.4 Name Plates

Switchgear data nameplates shall be engraved or stamped type and mounted in accessible location. Photographic imprinting is not acceptable. Where weatherproof switchgear is installed the nameplates shall bear the CSA designation "C22.2 No. 94" and type of enclosures

9.2 Metering Compartments – 13.8kV Switchgear

The following switchgear components shall be installed within separate compartments formed by sheet steel barriers:

(a) Each set of metering current transformers and each set of metering voltage transformer fuses.

(b) Each set of voltage transformers.

9.3 Metering Compartment – 27.6 kV Switchgear

The current transformers and voltage transformers can be installed in the same compartment. Barriers and voltage transformers fuses are not required.

9.4 Compartments and Openings

There shall be no openings whatsoever in compartment walls, which will permit the flow of ionized gases or flame into adjacent compartments.

9.5 Primary Connections between Compartments

Where the primary connections pass from one compartment to another compartment, the through-bushings installed in metallic barriers shall be rated fully at the same insulation level as the switchgear. Insulating material between compartments is not permitted.

9.6 Access Doors – 13.8 kV Switchgear

Individual hinged access doors are required to provide access to the following compartments:

(a) Each set of metering current transformers and each set of voltage transformer fuses.

(b) Each set of voltage transformers.

9.7 Access Doors – 27.6 kV Switchgear

A single hinged access door is required to give access to the current transformers and voltage transformers.

9.8 Hinged Access Doors

All hinged outer access doors shall open at least 135° and all hinged inner doors shall open at least 90°.

9.8.1 Stops on Access Doors

Access doors shall have stops to hold the door in their fully open position.

9.9 Padlock Hasps

Access doors shall be equipped with padlock hasps measuring at least 30mm wide by 5mm thick capable of accepting a standard Toronto Hydro padlock with a 8mm shackle.

9.10 Securing Access Doors

Access doors shall be adequately secured with either 25mm knurled head captive bolts, which require no tools to unscrew, or handles with at least three latching points.

9.11 Barriers – 13.8 kV Switchgear

9.11.1 Requirement for Barriers

Phase to phase and phase to ground barriers shall be installed on each set of fixed metering voltage transformer fuses.

Such barriers shall extend from the base of the insulator supports to a point 50mm beyond the fuse ferrules.

9.11.2 Type of Barriers

The barriers must be white, flame retardant insulating material meeting N.E.M.A. requirements for grade GPO-3 and be minimum 5mm thick.

***Note: Barriers not required on 27.6kV switchgear**.

9.12 Electrical Clearances

9.12.1 Bare Conductors

The phase to phase and phase to ground clearances of bare conductors and other current carrying parts shall be in accordance with the requirements of CSA Standard C22.2 No. 31.

9.12.2 Connection Clearances

Where 13.8kV connections are made to any components supplied or installed by Toronto Hydro (e.g. current and voltage transformers and or fuses), such connections shall be assumed to be bare and full CSA through air clearances shall be maintained.

10.0 TORONTO HYDRO METERING REQUIREMENTS

10.1 General Information

10.1.1 Supply of Metering Equipment For Switchgear Assemblies

Toronto Hydro will supply to the switchgear manufacturer current transformers, voltage transformers and/or primary fuse supports, of a type determined by Toronto Hydro, for installation and connection by the manufacturer during the construction of the switchgear. The switchgear manufacturers shall at no time disassemble and/or change in any manner the Toronto Hydro equipment sent to them. Meters, fuses, test blocks, secondary wiring and associated equipment required for Toronto Hydro revenue metering will be supplied and installed by Toronto Hydro after installation of the switchgear at the service site.

The switchgear manufacturer and or electrical contractor is to make all primary connections in the revenue metering compartment of the switchgear including the appropriate ground connections (#2/0) to the metering transformers whenever a ground lug is provided on the base of the metering transformers.

10.1.2 Connections

The voltage transformers shall be connected on the line side of the current transformers. Customers' instrumentation shall be connected on the load side of the Toronto Hydro metering, unless special approval is obtained.

10.1.3 Equipment Mounting

Metering transformers and/or primary fuse supports shall be mounted in an arrangement acceptable to Toronto Hydro. They must be capable of being

easily installed or removed without access to other compartments and be readily accessible with readily accessible secondary terminals.

(Refer to sections 9.2 and 9.3 for compartment requirements. Also, see diagram #2 for 13.8kV switchgear and diagram #3 for 27.6 kV switchgear)

10.1.4 Internal Conduit and Fittings – 13.8kV Swtichgear

A 25mm rigid conduit with bushings shall be installed in the switchgear between the current transformers and the voltage transformers for the secondary wiring - see diagram #2 for location. Flexible conduit is not acceptable.

10.1.5 Internal Conduit and Fittings – 27.6 kV Switchgear

A 25mm rigid conduit with bushings shall be installed between the current transformer and voltage transformer secondary terminal boxes and a 260mm x 260mm junction box (c/w cover). The junction box shall be located on the side-wall of the metering cell near the front by the access door. See diagram #3. Flexible conduit is not acceptable.

10.2 Current Transformers

10.2.1 Number of Current Transformers

Provisions shall be made for three current transformers, although in some cases only two will be installed in each metering current transformer compartment.

10.2.2 Clearance and Spacing

The electrical clearance around the current transformers with respect to 13.8kV and 27.6kV bus sections or conductors shall meet the requirements of the latest CSA standard C22.2 No. 31.

10.2.3 Polarity and Mounting Arrangement

Metering current transformers shall be installed with their polarity marks towards the incoming Toronto Hydro lines. The metering current transformers are to be mounted across the front of the cells. Front to back mounting is not acceptable.

10.3 Voltage Transformers, Fuse Supports and Fuses

10.3.1 Fuse Supports and Fuses

Metering installations for 13.8kV switchgear shall have three primary fuse supports and fuses for each set of voltage transformers. Fuses will be supplied

and installed by Toronto Hydro at the time of meter installation. Fuse supports are not required for 27.6kV switchgear.

10.3.2 Voltage Transformer Connections – 13.8kV Switchgear

(a) The minimum acceptable copper cable (or equivalent bar) size for primary connections shall be #4/0 AWG or 11 mm diameter copper rod between the main bus and the fuse supports and #6 AWG between the current limiting fuses and the voltage transformers.

(b) Where the primary connections pass from one compartment to another compartment through a metal barrier, through bushings shall be provided. Insulating material between compartments is not permitted.

10.3.3 Voltage Transformer Connections – 27.6kV Switchgear

The minimum acceptable copper cable (or equipment bar) size for primary connections shall be #2 AWG or 6mm diameter copper rod between the main bus and the voltage transformers.

10.3.4 Mounting Arrangements – 13.8kV Switchgear

The voltage transformers and fuses must be installed in a fixed position. Draw-out or swing-out arrangements are not acceptable for revenue metering installations. See diagram #2 for preferred arrangement.

Revenue metering voltage transformers shall comply with the following:

(a) Revenue metering voltage transformers must be mounted on the base plate in the metering cell. The voltage transformer fuse supports shall be mounted in the compartment directly above {Refer to Clause 9.2 (a)}.

(b) The access opening for the voltage transformer compartment shall have a clear height of 0.66 metres minimum.

(c) Primary fuses supports shall be mounted so that the center line of each fuse is approximately 1.2 metres above the floor but in no case less than 0.9 metres or more than 1.5 metres.

(d) The voltage transformers are to be mounted with their secondary terminal blocks located at the front of the switchgear near the access doors.

10.3.5 Mounting Arrangements - 27.6 kV Switchgear

The voltage transformers must be installed in a fixed position. Draw-out or swing-out arrangements are not acceptable for revenue metering. See diagram #3 for preferred arrangement.

The voltage transformers are to be mounted with their secondary terminal blocks located at the front of the switchgear, near the access doors.

10.4 Meter Cabinet and Conduit Installation

10.4.1 Meter Cabinet

A CSA approved meter cabinet shall be supplied and installed by the customer in a protected and accessible location approved by Toronto Hydro.

(a) For indoor installations the meter cabinet shall be installed indoors, inside the electrical room. Where the meter cabinet is located in an area equipped with a sprinkler system, the meter cabinet is to be weatherproof.

(b) For outdoor substations the meter cabinet shall be mounted in an adjacent building; if this is not practicable the cabinet must be weatherproof, equipped with door stops and located outdoors. The location and mounting are to be approved by Toronto Hydro.

(c) The top of the cabinet shall not exceed 1.8 metres above floor level or finished grade. The bottom of the cabinet shall not normally be less than 0.6 metres above floor level or finished grade.

(d) A clear working space of 0.9m is to be provided in front of the meter cabinet. In order to maintain this clearance, the customer at the request of Toronto Hydro may be required to install bollards in front of the meter cabinet area.

(e) Revenue meters shall not be installed in or on the switchgear.

(f) A #2/0 bare copper ground wire is to be installed from the system ground in the electrical room to the exterior of the meter cabinet.

10.4.2 Cabinet Size and Construction

(a) The meter cabinet size shall normally be 915mm wide x 915mm high x 305mm deep. For specialized meter installations involving totalizing pulse-metering equipment, Toronto Hydro shall be consulted regarding cabinet requirements since circumstances may require a cabinet of different dimensions.

(b) The cabinets shall be constructed of sheet steel of a minimum of #14, MSG. They shall be equipped with a removable interior mounting panel of sheet steel of minimum of #12 MSG. This panel shall be 80mm narrower than the width and 80mm shorter than the height of the cabinet and be mounted to permit a clearance of 13mm behind it.

(c) Cabinets shall be equipped with hinged double doors opening at the middle. Doors shall be provided with a non-locking type latch and handle or latch-handle combinations and shall not have more than three latching points.

10.4.3 Metering Conduit

(a) A conduit, for the exclusive use for the Toronto Hydro meter wiring, shall be provided by the customer and installed between the cubicle in the switchgear containing the metering transformers and the meter cabinet. The maximum length of conduit shall be no longer than 30metres. The customer shall supply and install a conduit of a nominal diameter of not less than 51mm. The conduit is to terminate at the cubicle as shown on diagram #2 and #3.

(b) The number of bends shall be kept to a minimum but in no case no more than three (3) 90° bends should be installed. Pull boxes and or 'LBs' are not permitted.

(c) The Electrical Contractor shall install a strong nylon, polyrope or equivalent pull line in the conduit between each metering transformer compartment and the meter cabinet leaving 1.5metres excess at each end.

10.5 Remote Metering (RIMS) – Services 200 kW and Greater

The customer is to provide and install the following:

(a) 1- 13mm (½") EMT conduit c/w bushings at both ends between the revenue metering cabinet and the telephone room (punch-board). The 13mm (½") EMT is to terminate at the top right corner of the meter cabinet.

A 2 pair (4 conductor) telephone cable is to be installed in the 13mm (½") conduit. A RJ11 (4 pin) telephone jack is also to be provided and installed on the telephone cable in the meter cabinet. The telephone jack is to be left at the bottom of the meter cabinet with enough telephone cable to allow mounting the jack anywhere in the cabinet. The telephone cable terminating in the telephone room is to be clearly labeled "TORONTO HYDRO METERING".

(b) Toronto Hydro will arrange to have the telephone line activated. Customer owned telephone lines or customer shared telephone lines are not acceptable.

(c) 1-120 Volt duplex receptacle, to be located at the bottom right corner inside the meter cabinet. The receptacle is to be connected to an uninterruptible power supply (UPS).

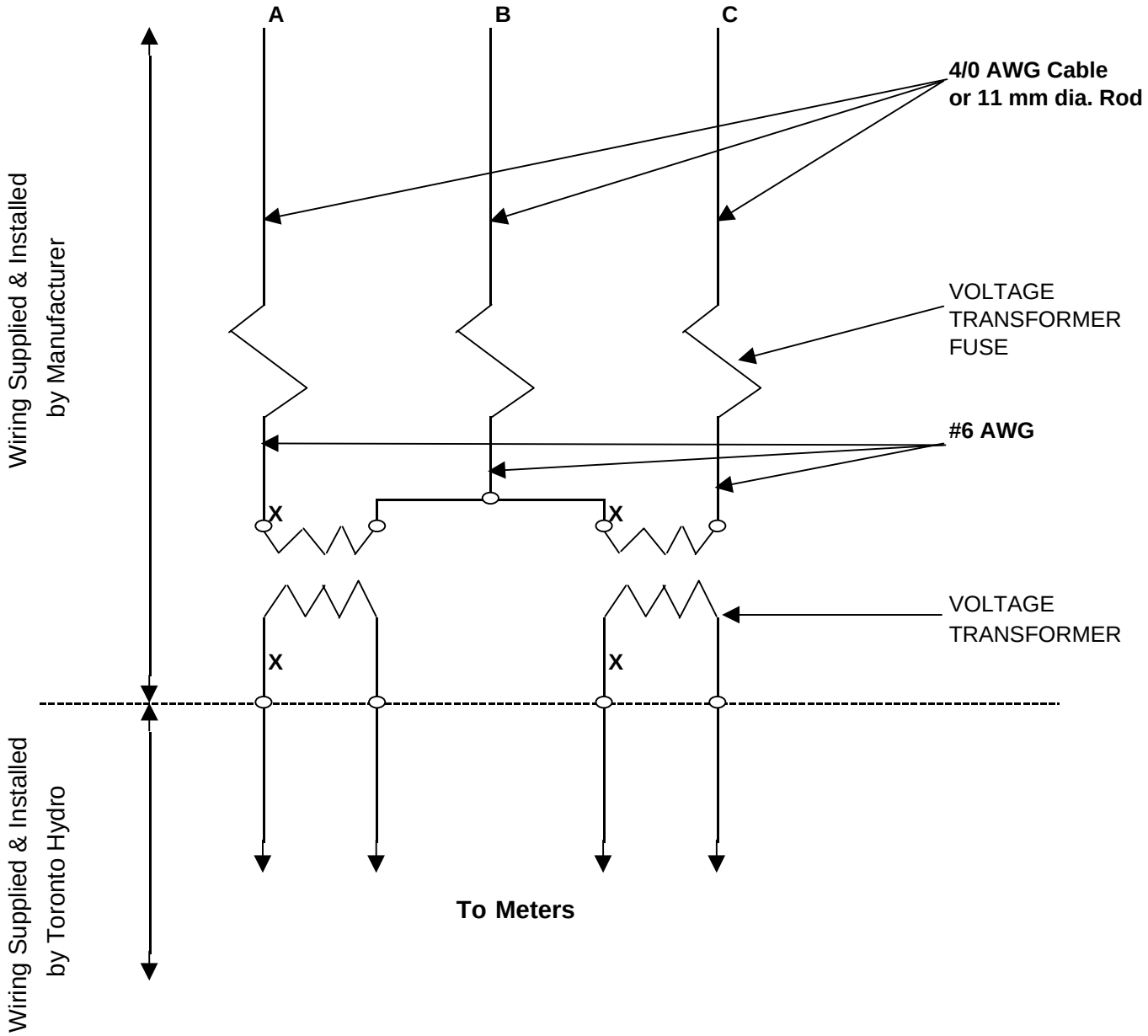
(d) The name and phone number of an on site contact person.

10.6 Pole/Structure Mounted 27.6kV Outdoor Substations

The customer shall provide facilities for mounting revenue metering transformers and or meters on the pole or structure. This type of arrangement will be approved on an individual basis as a special installation.

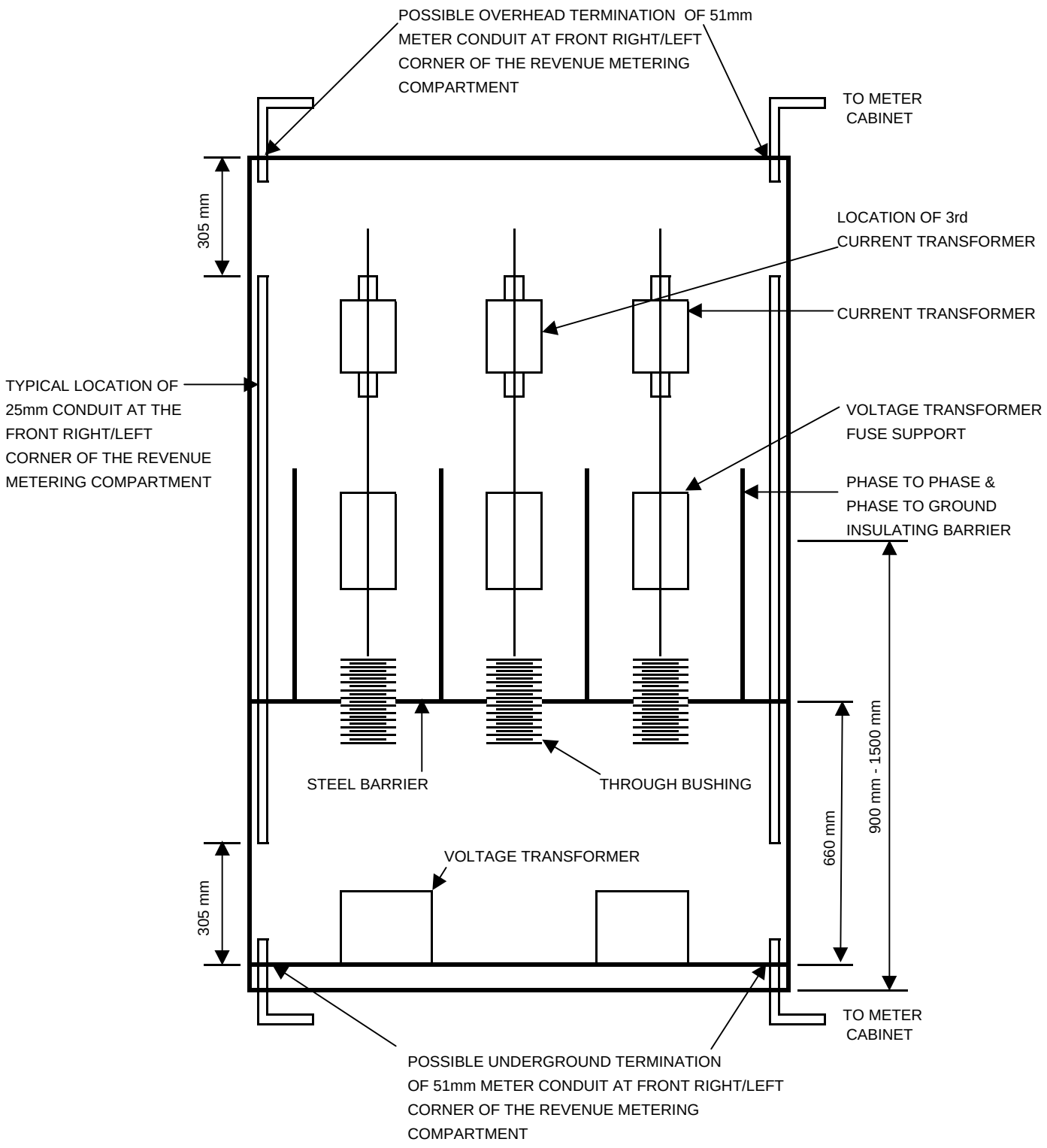
11.0 DIAGRAMS

FIXED MOUNTING



Connections to Revenue Metering
Voltage Transformers - 13.8 kV Switchgear - 3 Phase 3 Wire

Diagram #1



NOTE:

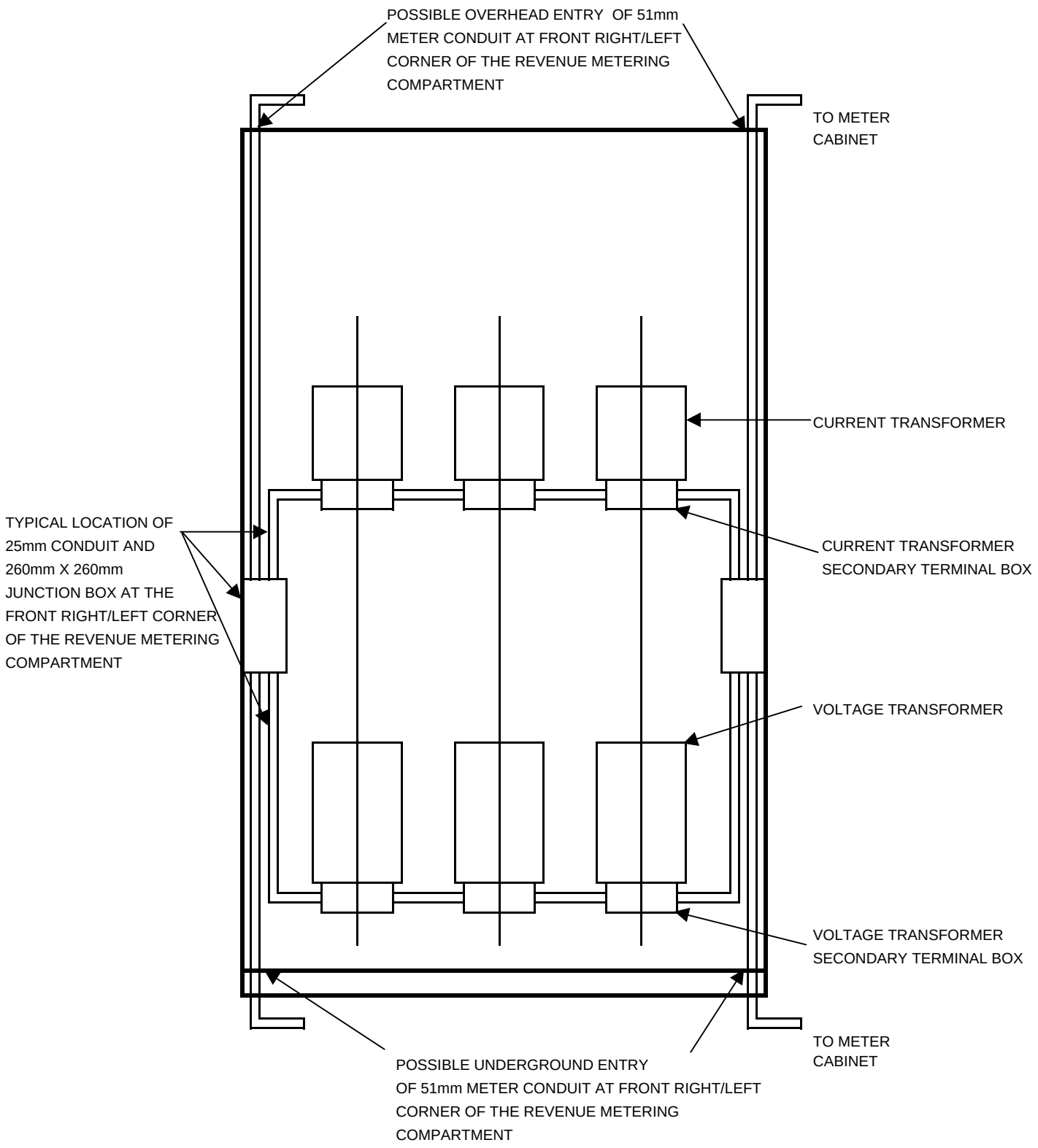
Current transformers and the voltage transfomer fuse supports are to be on the same vertical plane.

Refer to Section 10 for detailed specifications.

(DRAWING NOT TO SCALE)

Metering Compartment Front View Showing Relative Position of Metering Transformers and Fuse Supports - 13.8 kV Switchgear - 3 Phase 3 Wire

Diagram #2



NOTE:

Current transformers and the voltage transformers are to be on the same vertical plane.

Refer to Section 10 for detailed specifications.

(DRAWING NOT TO SCALE)

Metering Compartment Front View Showing Relative Position of Metering Transformers - 27.6 kV Switchgear - 3 Phase 4 Wire

Diagram #3

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Construction Contractor Qualification Application for Contestable Work

Version 1.0

January 23, 2007

SECTION 6 – Reference #8

INSTRUCTIONS TO CONTRACTORS

1. INTRODUCTION

(i) This Construction Contractor Qualification Application (the "Application ") is being issued and administered by the Toronto Hydro-Electric System Limited ("THESL") Procurement Department on behalf of THESL, "Toronto Hydro"), in order to Qualify one or more contractors that may result, if approved by Toronto Hydro, in contractors being approved to undertake construction of contestable work for customers as defined in the Toronto Hydro Conditions of Service and as described in relation to the project categories listed herein.

(ii) A contractor's designation as Qualified signifies that the Applicant has met the minimum requirements established by Toronto Hydro, and does not mean that the contractor is on equal footing with other Qualified contractors.

(iii) Toronto Hydro reserves the right, in its sole discretion, to seek out and obtain any additional information to confirm the qualification of the Applicant for specific categories of work.

2. QUALIFICATION

(i) Contractors interested in being designated as Qualified for purposes of undertaking contestable work for customers, shall complete and submit the following information to Toronto Hydro no later than 30 business days prior to their selection by a customer to undertake contestable work:

a) a duly signed copy of the Contractor Qualification Application Certificate;

b) Section One – identification of project categories of interest;

c) Section Two – the contractor's business information;

d) Section Three – references for construction projects the contractor has completed;

e) Section Four – health and safety information;

f) Section Five – minimum employee training requirements;

g) Section Six – vehicle and equipment description capabilities.

h) Details describing the Contractor’s Quality Assurance Program

(ii) Failure to complete the Application in its entirety or with sufficient information and/or detail, or if the Application contains fraudulent, false, deceptive or misleading information, may result in disqualification.

(iii) All responses and accompanying documentation submitted by contractors shall become the property of Toronto Hydro and will not be returned.

(iv) Contractors that have previously been Qualified for contestable work and wish to renew their status as Qualified contractors shall complete and submit the Application, as amended from time to time by Toronto Hydro, in its sole discretion, every 18 months or such shorter period of time as determined by Toronto Hydro, in its sole discretion.

3. SUBCONTRACTORS

If Toronto Hydro elects, in its sole discretion, to approve the contractor as a Qualified contractor for specified categories of work, the contractor shall be responsible for ensuring that any subcontractors that may be retained by the contractor are Qualified in accordance with the requirements of this Application prior to performing any contestable work. Any subcontractors (still requiring qualification approval by Toronto Hydro) must also submit an Application requesting to be designated as Qualified to undertake contestable work as described herein. In such a case, the contractor will submit along with their Application, separate Applications for any subcontractors the contractor may retain for specified categories of work.

4. CONFLICTS OF INTEREST

Contractors shall disclose in their response to this Application and on an ongoing basis thereafter any conflict of interest, real or perceived, that exists now or may exist in the future, with respect to any matters in this Application, and resulting qualification approval thereto, or in relation to Toronto Hydro, including the disclosure of any personal or business relationships between the contractor, or its directors, officers, employees, agents, design, architectural or consulting firms, and contractors and Toronto Hydro or its directors, officers, employees, agents and contractors.

5. EVALUATION

(i) All Applications will be evaluated based on any number of criteria which Toronto Hydro, in its sole discretion, considers relevant, including, without limitation, the following:

(a) technical capacity, skill and competence of the contractor;

(b) applicable experience;

(c) health and safety performance;

(d) any other factor or criterion that Toronto Hydro, in its sole discretion, deems relevant.

(ii) Toronto Hydro is not obligated to inform contractors of the relative weight to be given to any particular evaluation criterion, or to provide reasons to any contractor with respect to any exercise of Toronto Hydro's discretion.

6. INVESTIGATION

Toronto Hydro may, at any time, investigate and verify the information submitted by a contractor and any other relevant information from the sources identified by the contractor in this Application and/or other independent sources.

7. PERSONAL INFORMATION

If, and to the extent that any information provided in this Application is personal information of an identifiable individual, the contractor represents and warrants that it has obtained any and all consents required under applicable personal information laws to permit Toronto Hydro to collect such information from the contractor and to use such information in considering the Application.

8. CONFIDENTIALITY

(i) All information submitted by a contractor in accordance with the requirements of this Application will be treated as confidential by Toronto Hydro and used only for the purpose of establishing the contractor's ability to satisfy the requirements of the Application and will not be disclosed to any third party except as necessary to investigate and verify the information submitted by the contractor as set forth in Section 3 and process this Application or as permitted or required by law.

9. SELECTION OF CONTRACTORS

(i) Contractors that satisfy the criteria and conditions of this Application will be notified by Toronto Hydro of their designation as contractors Qualified to undertake the specified categories of contestable construction work. The designation as Qualified shall be in effect for a period not to exceed 18 months after which time the contractor must re-submit an Application.

(ii) Contractors that are designated as Qualified to undertake contestable work shall immediately notify THESL's Procurement contact at the address set forth in Section 12 of any changes at any time to the information submitted in the Application. Without limiting the generality of the foregoing, if a contractor changes its name, it shall provide THESL's Procurement contact with a detailed explanation for the change of name.

(iii) Toronto Hydro may, in its sole discretion, temporarily or permanently disqualify or suspend a Qualified contractor that fails to maintain compliance with:

(a) any statutes, regulations, by-laws, codes, standards or guidelines of municipal, provincial or federal authorities (collectively "Applicable Laws") that are applicable to this Application or the contract for the work on a particular project, including, without limitation, all applicable Ontario Energy Board codes, rules, or guidelines; or

(b) the rules, guidelines or specifications established by Toronto Hydro from time to time of which the contractor has been advised; or

(c) the requirements of this Application.

10. NO LIABILITY

All costs, expenses, losses, damages or liabilities that may be incurred by the contractor as a result of or arising out of submitting this Application or Toronto Hydro's rejection of this Application or the contractor's subsequent temporary or permanent disqualification or suspension as a Qualified contractor shall be borne entirely by the contractor and Toronto Hydro and its directors, officers, employees, agents and contractors shall not be liable for any costs, losses, damages or liabilities whatsoever in the event the contractor is not Qualified, or the contractor is subsequently temporarily or permanently disqualified or suspended as a Qualified contractor.

11 APPROVAL OF QUALIFICATIONS FOR SPECIFIED CATEGORIES OF WORK

Contractors designated as Qualified shall be so designated only for contestable work for customers for the project categories and project types described by the contractor in the Application as set out in Section One.

12. SUBMISSION OF APPLICATIONS AND ENQUIRIES

Contractors shall submit Qualification Applications to undertake contestable work to THESL's Procurement representative described below. Questions regarding Applications shall be directed to THESL's Procurement representative in writing as follows:

Dan Doyle
Procurement Department
Toronto Hydro-Electric System Limited
500 Commissioners Street
Toronto, Ontario,
M4M 3N7
Telephone: (416) 542-2725
Fax: (416) 542-2663
Email: DDoyle@torontohydro.com

CONTRACTOR QUALIFICATION APPLICATION
("Certificate")

I, the undersigned, in submitting this Application on behalf of [_____] (the "Contractor"), do hereby certify, on behalf of the Contractor and not in my personal capacity, that:

1. I understand that the purpose of qualification is to ensure that all contractors interested in performing contestable work have the necessary minimum technical and managerial competence to execute the work, and that Toronto Hydro may conduct additional pre-qualifications for specific projects.

2. I understand that Toronto Hydro may, in its sole discretion, may refuse to qualify a contractor, or temporarily or permanently disqualify or suspend a qualified Contractor that fails to maintain compliance with:

    a. any Applicable Laws that are applicable to this Application or the contract for the work on a particular project, including, without limitation, all applicable Ontario Energy Board codes, rules, or guidelines; or

    b. the rules, guidelines or specifications established by Toronto Hydro from time to time of which the contractor has been advised; or

    c. the requirements of this Application.

3. I understand that the information submitted in the accompanying Application shall be treated as confidential, used only for the purpose of determining the Contractor's qualification to perform contestable work and will not be disclosed to any third party except as necessary to investigate and verify the information submitted by the Contractor as set forth in Section 3 and process this Application or as permitted or required by law.

4. I understand that the information submitted in the accompanying Application shall become the property of Toronto Hydro and will not be returned.

5. I understand and agree that qualification to perform contestable work does not entitle the Contractor to be invited to submit formal tenders for any of Toronto Hydro's projects.

6. I understand that the information submitted herein is subject to verification and that additional relevant information may be obtained, if required, from references named herein and/or other independent sources. I hereby consent to these sources providing this information and to Toronto Hydro independently verifying this information.

7. I represent and warrant that the Contractor has obtained any and all consents required under applicable personal information laws to provide the personal information of identifiable individuals in this Application and to permit THESL to collect such information and use such information in considering the Application.

8. I understand and agree that it will be the Contractor's obligation to ensure any subcontractors retained by it shall qualify in accordance with the requirements of this Application prior to performing any contestable work.

9. Any and all potential conflicts of interest between the Contractor and Toronto Hydro are expressly identified and fully disclosed by the Contractor in the Contractor's Application,

including the disclosure of any personal or business relationships between the Contractor, or its directors, officers, employees, agents and contractors and Toronto Hydro or its directors, officers, employees, agents and contractors.

10. I understand and agree that all costs, expenses, losses, damages or liabilities that may be incurred by the Contractor as a result of or arising out of submitting this Application or Toronto Hydro's rejection of this Application or the Contractor's subsequent temporary or permanent disqualification or suspension as a qualified contractor shall be borne entirely by the Contractor and that Toronto Hydro and its directors, officers, employees, agents and contractors shall not be liable for any costs, losses, damages or liabilities whatsoever in the event the Contractor is not qualified, or the Contractor is subsequently temporarily or permanently disqualified or suspended as a qualified contractor.

11. I understand that the accompanying Application submitted by the Contractor may be disqualified at any time if this Certificate is found not to be true and complete in every respect.

12. I have read, understand and agree to comply with the statements made in this Certificate.

13. I am duly authorized by the Contractor to sign this Certificate, and to submit the accompanying Application, on behalf of the Contractor.

14. I understand and agree that Toronto Hydro does not make any representation or warranty regarding any contractor selected by the Customer to do any work regardless of whether the contractor has completed the requirements set by Toronto Hydro or not and shall have no liability to the Customer in respect of such work.

_____
Contractor's Full Corporate/Business/Partnership Name

_____
Authorized Representative's Signature

_____
Name

_____
Title

_____
Date

Section One: Project Categories

Contractors shall identify the project category or categories for which the contractors are seeking to be Qualified by marking the applicable boxes:

Category and Project Type

Civil Hydro-Electric Distribution Work:

- Duct & Cable Chamber Systems
- Underground Rebuilds & Voltage Conversions
- New Residential Subdivisions
- Industrial Subdivisions
- Street Lights
- Road Crossings
- Test Holes
- Submersible Vault Drains
- FRE Duct Installations (including bridges)

Underground Hydro-Electric Distribution Work (Primary):

- Splicing & Terminating
- Submersible Vaults
- Building Vaults
- 1/0 Al. Primary Splicing
- Cable Pulling
-

Underground Hydro-Electric Distribution Work (Secondary):

- Service Conversion Overhead to Underground
- Electrical Room Rework
- Terminating In-Tap Boxes & Meter-bases
- 1/0 Al. Primary Splicing
- Cable Pulling

Overhead Hydro-Electric Distribution Work:

- Line Work
- Services
- Street Lights
- Underpass Lighting
- Pole Installations

Miscellaneous Work:

Excavation using water pressure / vacuum system truck

SECTION TWO: BUSINESS INFORMATION

If required, contractors may supplement the information requested with an additional sheet(s) marked as "Appendix A – Business Information".

Business Contact Information			
Business name (Legal Name / Operating name):			
Phone:	Fax:	Email:	Internet address:
Registered company address:			
City:	Province:	Postal Code:	
Contact person:			
Title:	Phone:	Fax:	Email:
Year business established:			
Quality assurance program(s): Yes/No *(submit a copy and any related documentation thereto)*	Date of implementation:		
Number of full-time employees:	Union affiliation:		
Organizational chart: Yes/No *(submit)*	Mission statement: Yes/No *(submit)*		

Officers/Directors/Partners/Principals		
1. Name:	Title:	Phone:
2. Name:	Title:	Phone:
3. Name:	Title:	Phone:
4. Name:	Title:	Phone:
5. Name:	Title:	Phone:
6. Name:	Title:	Phone:

SECTION THREE: PROJECTS COMPLETED

Contractors shall provide a minimum of five (5) project references, from at least two (2) different sources, for the projects completed as of the date of submitting this Application. If required, Contractors may supplement the information requested with an additional sheet(s) marked as "Appendix C – Projects Completed".

1. Project title:		
Location:	Description:	
Duration of project:	Date completed:	
Project owner:	Project value: $	
Contact Person:	Title:	Phone:
2. Project title:		
Location:	Description:	
Duration of project:	Date completed:	
Project owner:	Project value: $	
Contact Person:	Title:	Phone:
3, Project title:		
Location:	Description:	
Duration of project:	Date completed:	
Project owner:	Project value: $	
Contact Person:	Title:	Phone:
4. Project title:		
Location:	Description:	
Duration of project:	Date completed:	
Project owner:	Project value: $	
Contact person:	Title:	Phone:
5. Project title:		
Location:	Description:	
Duration of project:	Date completed:	
Project owner:	Project value:	
Contact person:	Title:	Phone:

SECTION FOUR: HEALTH AND SAFETY INFORMATION

1. REQUIRED DOCUMENTATION

(i) Contractors shall submit the following information with their Application:

(a) a signed and dated copy of the contractor's health and safety policy, which complies with the requirements set out in the *Occupational Health and Safety Act* and the regulations thereunder, as amended (the "OHSA");

(b) a description of the contractor's health and safety program;

(c) a description of the training programs provided to the contractor's employees;

(d) the training records of each employee that may perform work on the project(s);

(e) a written statement certifying that each of the contractor's supervisors that may perform work on the project(s) are "competent persons", as that term is defined in the OHSA, and that each of the contractor's employees that may perform work on the project(s) are "competent workers" as that term is defined in the OHSA;

(f) a copy of the contractor's Workplace Safety and Insurance Board ("WSIB") NEER/CAD injury experience report for the current and previous year;

(g) the names and WSIB certification numbers of the contractor's Joint Health and Safety Committee co-chairs;

(h) a WSIB Cost and Frequency Report for the shorter of the last five (5) years and the number of years the contractor has been in business;

(i) a list of all supervisors who will co-ordinate work and safety during the project; and

(j) a statement certifying that the contractor is a member in good standing of the Electrical and Utilities Safety Association ("EUSA").

2. CERTIFICATES

(i) Contractors shall submit any certificates or licenses required by all Applicable Laws that are applicable to this Application, including, without limitation:

(a) a copy of the contractor's WSIB Certificate of Clearance;

(b) Lineman Ontario Provincial Classification or Journeyperson Certificates issued by the Municipal Electric Association ("MEA") or current equivalent for each employee;

(c) Electrical Awareness Certificates issued by the EUSA for each employee;

(d) a copy of the contractor's Commercial Vehicle Operator Certificate issued by the Ministry of Transportation (Ontario) (the "MTO");

(e) such other certificates or licenses required by any Applicable Laws or industry standards that may apply to this Application.

SECTION FIVE: MINIMUM EMPLOYEE TRAINING REQUIREMENTS

Contractors shall identify the areas of training its employees have completed by marking the applicable boxes.

REQUIRED TRAINING	CIVIL	ELECTRICAL < 750 VOLTS UNDERGROUND	ELECTRICAL > 750 VOLTS UNDERGROUND	ELECTRICAL < 750 VOLTS OVERHEAD	ELECTRICAL > 750 VOLTS OVERHEAD	
MEA-Certified Journeyperson	N/A*					
Electrical Safety Awareness						
Excavation/Shoring		N/A	N/A	N/A	N/A	
OHSA						
EUSA Rules	N/A					

* N/A means "Not Applicable

SECTION SIX: VEHICLE & EQUIPMENT DESCRIPTION CAPABILITIES

Contractors shall identify all vehicles owned or leased by the contractor that will or may be used to perform work on a project for Toronto Hydro. If required, contractors may supplement the information requested with an additional sheet(s) marked as "Appendix F – Vehicle Description Capabilities".

VEHICLE #	DESCRIPTION	AGE [indicate year]	MTO		CSA C225-M1988 and/or CSA C225-00		OTHER
			Certificate [specify]	Date	Specify	Date	

CONDITIONS OF SERVICE - 2007 REVISION SUMMARY

Section	Section Title	Summary of Changes to the Conditions of Service
1.1.1	Distribution Overview	Revised description of 27.6 kV distribution loop system
1.8	Disputes	Revised contact to reflect current regular business hours between 8:30 AM and 4:40 PM Monday to Friday
2.1.1.1	Connection Charges	Reflected DSC changes for Basic Connection Costs (collected through the economic evaluation for Expansions) and for Variable Connection Costs (collected directly from the Customer)
2.1.2	Expansions' Offer to Connect	Reflected DSC changes such as 1) the historical average distribution system enhancement capital cost per kW; 2) inclusion of Basic Connection costs in the economic evaluation
2.1.2.1	Offer to Connect & Alternative Bid Work	Reflected DSC changes such as 1) use of qualified contractors and methodology for treating contestable work, 2) requirement for the Customer to post an expansion deposit in the amount of 10% of the value of contestable work
2.1.2.2.1	Offer to Connect – Content & Process	Added a new section to outline the new requirements of the DSC that the distributor must include in the Offer to Connect
2.1.2.2.2	Transfer Price for Contestable Work	Added a new section to outline the new requirements of the DSC regarding the transfer price to be included in the economic evaluation of the expansion
2.1.2.2.3	Final Economic Evaluation & Capital Contribution Settlement	Added a new section to outline the new requirements of the DSC that the distributor carry out the final economic evaluation, once the new distribution facilities and or connection assets are energized and settle any cost difference with the Customer
2.1.2.3	Expansion Deposit	Revised the previous THESL policy to restrict the requirement for Expansion Deposits to Class 3 Customers requesting multi-phase developments, Class 4 and Class 5. Also, included the new DSC requirement for the Customer to post an expansion deposit in the amount of 10% of the value of the contestable work and the methodology and timing for the distributor to return the residual expansion deposit to the Customer
2.1.2.6	Feeder Capacity Optimization	Added a new section to outline assignment of feeder capacity past the five-year connection horizon
2.1.7.4	Connection Agreements	Added a new clause stating that the terms of a Connection Agreement have priority over the Conditions of Service
2.3.4.2	Supply Voltage	Revised clause 2.3.4.2 to allow 750 kVA padmounted transformers (items ii and iii) in private property
2.3.4.2	600 V Delta Services	Clarified that 600 V delta services are no longer allowed (included only for existing metering)
2.3.4.3	Multiple Connections to Main Distribution System	Added a new section to outline multiple connection to the main distribution system
2.3.6	Emergency Back-up Generation Facilities	Included embedded generation facilities that are used exclusively for load displacement purposes to be treated as Emergency Back-up Generation. However, their generator must not parallel with Toronto Hydro's distribution system for longer than 100 ms under any circumstances
2.3.7.1.1	Metering Requirements for Multi-Unit Sites and Condominium Corporations	Revised the former Multi-Unit Site section to outline the new requirement for individual suite metering for new Multi-Unit Sites. This requirement will also apply to all existing and future Condominium Corporations (refer to proposed Regulation)

Section	Section Title	Summary of Changes to the Conditions of Service
2.4.3	Deposits	Added definition of 'Residential Condominium' to comply with an earlier DSC revision
3.2 (g)	General Service	Revised clause (g) concerning overtime charges to customer for THESL's maintenance work. The previous requirement was more restrictive for the customer
3.2 (i)	General Service	Relaxed the requirements for the Customer to pay for modifications of civil-owned infrastructure in private property. Modification to civil infrastructure will now be financed through hydro rates when these are part of THESL's enhancement projects. The previous requirement was more restrictive for the customer
3.5	Generation Connection	Revised entire Section 3.5 to include Net Metering and the OPA Standard Offer requirements
3.5.5	Technical Requirements	Revised technical requirements to include reference to the new CSA Standard for generators
3.5.7	Ontario Power Authority (OPA) Standard Offer Program for an Embedded Generation Facility	Added a new section to outline the Standard Offer Program for generators that meet the requirements of the OPA and those of THESL posted on the Toronto Hydro website
3.8	Unmetered Connections	Revised section to limit unmetered connections to loads less than 2 kW or other fixed loads such as traffic & railway crossing signals, pedestrian x-walk signals/beacons, bus shelters, telephone booths, CATV amplifiers, TTC switching devices. All other loads will be metered
3.8.1	Street Lighting	Revised section to reflect current ownership of municipal street lighting
Definition	Main Distribution System	Added a new definition: “main distribution system” means a distribution system less the connection assets
Table 2	Basic Connection and Disconnection Fees	Revised Service Connection fees by standardizing the Standard Basic Connection to $1,310.00 and specifying that the Variable Connection Charges will be collected in all cases directly from the Customer
Table 3	New or Upgraded Street Lighting Services	revised Table 3 to reflect current ownership of municipal street lighting
Reference	Connection Agreements	Replaced Generator Connection Agreement to reflect standard agreements issued by the OEB as part of the DSC. The former Connection Agreement is maintaind as Schedule B3 for generators larger than 10 MW
Reference	THESL Parallel Generation Requirements	revised technical requirements to include the new CSA Standard for generators
Reference	Other Reference Documents	Included P. Eng approval of standard design specification and referenced technical requirements to comply with requirements of ESA Regulation 22/04

LONG TERM DISTRIBUTION SYSTEM PLANNING PROCESS

INTRODUCTION

THESL maintains, renews and adds assets in accordance with an asset management model. The purpose of the model is to manage all distribution plant assets through their lifecycle to meet customer reliability, safety, and service needs while optimizing the value of the assets. The asset management model consists of an Asset Manager who is functionally separated within the company from the service providers. The Asset Manager decides what should be done, and when, based on the assessment of asset needs and then retains internal and external service providers to perform those tasks. The Asset Manager develops long-term asset management strategies and policies, develops all distribution plant capital investment programs, develops all distribution plant maintenance programs and ensures execution of programs by internal and external service providers.

Long term planning cannot be accomplished effectively without considering the requirements and plans of external Stakeholders. Coordination of programs with the City of Toronto, Toronto Transit Commission, Hydro One Networks Inc., other utilities and users of the street allowance are factored into, and integrated where possible with THESL projects.

New technology that offers improved asset efficiencies, reliability and operational benefits become embedded in the long term plans and get evaluated as part of the budget cycle.

The Asset Condition Assessment completed in 2006 and the 2007-2016 Electrical Distribution Capital Plan filed with the Board in February 2007 describe the investment requirements, and major shift in spending in 2007 and throughout the test years for

distribution system assets. Both documents are filed with this Application as Exhibit D1, Tab 8, Schedule 9 and Exhibit D1, Tab 8, Schedule 10, respectively. The shift in expenditures is due primarily to an extensive infrastructure renewal and replacement program required to maintain system reliability and availability within established performance targets. This increased investment will generally take the form of like-for-like replacement of assets taking into account advancements to assets based upon increased efficiency, higher reliability, and energy conservation.

For the general plant, including facilities and equipment, long-range capital plans are based upon performance improvement factors as well as support for distribution system rehabilitation efforts. The replacement of these assets is carried out on a priority-basis based on the following key internal drivers: public and employee safety, reliability, customer value, and asset condition.

To validate that long-term plans remain consistent with emerging requirements, and to delineate the detailed requirements for successive years, on an annual basis THESL's planning includes:

1) Confirmation of Corporate Strategy by Senior Management
2) Development of Sustaining Capital Investment plans
3) Development of Reactive Capital Investment plans

CONFIRMATION OF CORPORATE STRATEGY BY SENIOR MANAGEMENT

THESL's strategic direction and goals are set and reviewed by the President and other members of the senior management team on an annual basis as described in THESL's Business Planning Process filed at Exhibit C1, Tab 4, Schedule 1. The strategic goals provide instructions for reference by lower level management and unionized staff in developing justified business plans. The Asset Condition Assessment ("ACA") and the

2007-2016 Electrical Distribution Capital Plan concluded that THESL will need to spend a significant amount to refurbish large portions of its distribution plant over the next ten years. As with any long-term plan, the overall assumptions underlying the plan will be revisited annually, by THESL's Asset Management Division to ensure continued alignment.

DEVELOPMENT OF SUSTAINING CAPITAL INVESTMENT PLANS

The detailed investment plans for the upcoming year are balanced to provide Customer service reliability improvements where they are needed most, mitigation of maintenance costs and reduction of public safety risks. The amount of work to be performed during the period will consider available resources (both human and capital). The model for the prioritizing process is shown in Exhibit C1, Tab 7.

The investment plans for distribution capital are divided into six categories:

1) Underground Distribution System Rehabilitation of direct buried cables
2) Underground Distribution System Rehabilitation of cables in ducts
3) Overhead System
4) Network Transformers
5) Terminal Stations (Hydro One Supply Points)
6) Municipal Substations

Starting 2007 and on a go-forward basis, all distribution capital work will be broken down into these six categories. A detailed description of these six categories can be found in Exhibit D1 Tab 8, Schedule 1. Projects are developed in each category based on projected end of life cycle and other internal drivers such as safety, reliability, customer service, operational improvement, and capacity planning and external drivers such as communications utilities, the City of Toronto, and HONI. For General Plant, investments

will continue to be based upon performance improvement factors as well as support of the distribution system rehabilitation efforts.

DEVELOPMENT OF REACTIVE CAPITAL INVESTMENT

The reactive capital investment involves work that was not identified as part of specific projects. This work required is generally in response to component failures, and not complete system failures, so engineering design costs are not usually incurred.

Based on historical spending requirement, and asset performance data, funds are allocated to capture spending associated with this work. The main goal for allocating these funds is to keep system performance up to an acceptable standard by replacing assets on a like-for-like basis as they fail. Reactive capital funds are allocated into overhead or underground categories.

Asset replacement is required when components fail due to defects, aging, overload, weather conditions, and third party events such as vehicle accidents, crane activity around construction sites, excavations and flooding. Overhead failed components include poles, wires, transformers and overhead line hardware. Underground failed components include cables, splices, joints, transformers, switches and civil infrastructure.

A service interruption cause code analysis may be found at Exhibit B1, Tab 14, Schedule 1 of this Application.

DISTRIBUTION WORK PROGRAM PRIORITIZATION PROCESS

Capital, operating, and maintenance work programs are developed to address long-term asset requirements and short term emerging needs. Competition for scarce program resources means it is necessary for program dollars and resources to be budgeted to priority users, and that there is strong rationale for the programs that are executed annually.

THESL uses a detailed prioritization model, as part of its decision-making, for determining which distribution projects take priority for consideration in short-term plans and each budget year. The process ensures that investments are aligned to THESL's corporate strategic objectives, by ranking them according to five specific criteria. The criteria, developed by a multi-disciplinary team, are then applied using a "pair-wise comparison" to develop the relative weighting for each program. The objective of the prioritization process is to develop a portfolio of capital and operating programs that reflects the above rankings, and supports the long-term asset requirements.

The five criteria identified are as follows:

1) Risk Mitigation;
2) Financial;
3) Historical System Reliability;
4) Personnel Safety; and
5) Customer.

Forward-looking "Risk Mitigation" is the most heavily-weighted criterion and includes mitigation of negative impacts to system reliability and public safety.

"Financial" measures investment value including avoided maintenance costs, and reduction of reactive maintenance costs.

"Historical System Reliability" incorporates improvements to actual historical customer minutes out and actual historical number of customers interrupted.

"Personnel Safety" includes mitigation of risk associated with THESL personnel work practices.

"Customer" includes impacts to critical customers (e.g., customers on life-support systems, Red Cross, and hospitals), total kVA of affected load, and number of outages for individual customers.

Although the five criteria are separate and have different weights in the portfolio, there is a strong correlation between them such that most programs typically contribute to supporting more than one criterion.

A third-party software, Asset Investment Strategy ("AIS") developed by Davies Consulting Inc., is used to manage the prioritization process and is the decision support tool that facilitates portfolio development. The tool provides a structured methodology to evaluate diverse projects and programs across business units based on corporate drivers such as reliability, safety, and customer value.

AIS is being successfully used at other regulated utilities as a supporting tool in their budgeting process. It provides a structured framework to allocate financial resources. AIS also provides a common platform to document and justify assumptions in order to attain investment consistency. Additionally, AIS promotes a project challenge process that stimulates prudent discussion on the risks and benefits associated with each proposed

investment and provides for rapid development of scenarios and multiple scenario analysis.

An overview of the AIS approach and process flow is included at Exhibit C1, Tab 7, Schedule 2. A detailed breakdown of the criteria, including questions used to develop the relative rankings, is included in Exhibit C1, Tab 7, Schedule 3.

WORK PRIORITIZATION PROGRAM

ASSET INVESTMENT STRATEGY ("AIS") SOFTWARE

The purpose of the AIS program is to objectively prioritize investments from either a single business (e.g., distribution) or a multiple business unit (e.g., distribution, transmission, IT, fleet, customer service, etc.) perspective, facilitate management decision-making and allow for structured and objective scenario analysis of multiple projects. The AIS Program involves two equally important components: (1) a decision support software tool for objectively evaluating and prioritizing investments; and (2) a structured process for establishing project evaluation criteria and for challenging and testing evaluation assumptions.

The foundation of the AIS approach is the individual evaluation of investments (projects) against corporate or business unit strategic business drivers. By tying the evaluation of an investment to a company's strategy, AIS can determine which projects are most valuable to the company at the investment level and subsequently create a portfolio with maximum company value. Most of these business drivers are unique to each company with the exception of Financial Impact, which is a required evaluation criterion.

The Financial Impact strategic business driver is a qualitative assessment of the investment value as measured by various financial indices. The investment manager enters the cash flows, both positive and negative, into AIS and the tool calculates the financial indices indicating the quantitative (dollar) value of the project. In addition to the financial strength of the project, other more qualitative drivers are also evaluated. These qualitative drivers are specific to a utility and require project managers to answer a set of questions. Based on those answers the model determines the qualitative value of the project. For example, the operational improvement, customer satisfaction and

corporate responsibility business drivers are qualitative evaluations of the value of an investment, as defined by a series of questions specific to each area.

OVERVIEW OF THE AIS PROCESS

The AIS process is as important as the tool itself because the process is where the evaluation criteria are developed, the evaluation assumptions are challenged, and output analyzed for management decision-making. The following illustrates the AIS Process:

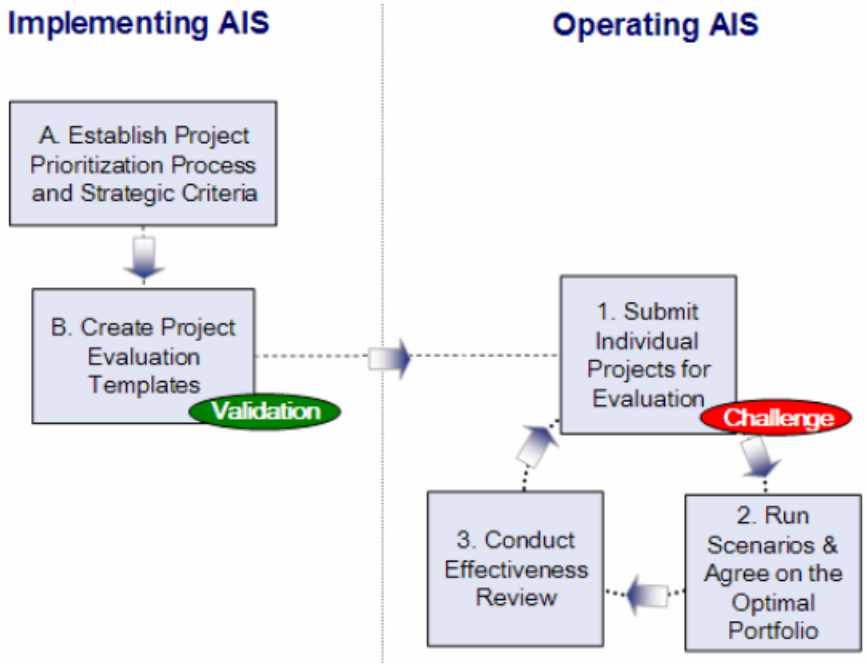


Figure 1: AIS Process

AIS Implementation Teams are selected from across the organization to collaborate and develop the AIS value framework. The framework consists of the strategic business drivers and a series of attributes and questions for each business driver. Business unit or senior level management along with the AIS Teams assign weights for each evaluation business driver and evaluation questions. These weights are applied to the answers to the evaluation questions for each project and determine the value of the individual projects.

After each project is input, it is evaluated by a project manager and challenged by peers and managers to determine if it indeed belongs in the portfolio of work for budget submission. All projects are stored in the AIS database and are then evaluated against each other to determine the most valuable portfolio subject to the budgetary constraint. The result of the evaluation and subsequent decision-making is an agreed set of investment priorities that are then incorporated into the finalized budget review.

WORK PROGRAM PRIORITIZATION

PRIORITIZATION SCORING CRITERIA

Each capital project is scored based on predetermined criteria. These criteria assist the Asset Manager to consistently prioritize the capital work to achieve maximum added value. The criteria considered are as follows:

1) Customer
2) Finance
3) Historical Reliability
4) Risk Mitigation (including System Reliability, Public Safety, Environmental)
5) THESL Personnel Safety

Customer

This criterion considers the size and criticality of customers who will benefit from the project both directly and indirectly. It also considers whether the project will benefit customers who have experienced multiple interruptions.

Finance

This criterion considers an economic evaluation of the project. The inputs into the cash flows are as follows:

- ***Capital Outlay:*** This represents the funds required to complete the project.

- ***Additional Future Flexibility:*** This represents the cash flows of the additional flexibility for future planning projects.

- ***Sale of land:*** This represents the value of the land arising from the decommissioning of station assets.

- ***Tax Shield:*** This represents the tax savings as a result of capital cost allowance. A corporate tax rate will be factored in.

- ***Salvage Value***: This represents the cost recovered or which could be recovered from assets when removed, sold, or scrapped. It is calculated by determining the quantity of materials multiplied by the salvage value per unit.

- ***Scheduled Maintenance Savings:*** It is assumed that for every major asset that was replaced, one cycle of maintenance related to that asset will be avoided in the future.

- ***Avoided Distribution Revenue Loss:*** During an outage, electricity consumption is interrupted and revenue is lost. The duration of the interruption, and the number and type of interrupted customers, determines the lost revenue. It is necessary therefore, to determine the type of customers as well as historical outage information to calculate the avoided distribution revenue loss associated with each project.

- ***Avoided Reactive Maintenance Expenditures:*** Each time there is an outage, reactive crews are sent out to investigate and rectify the problem. It is assumed that the project will avoid future outages for the affected feeders for a specified amount of time and thus reduce expenditures related to reactive maintenance.

The resultant cash flows are compared based on the following metrics: net present value ("NPV"), internal rate of return ("IRR"), Discounted Payback, and Equity Annuity Value.

Historical Reliability

This criterion considers two factors related to the actual historical reliability. The two factors are as follows:

- ***Total Customer Interruption Improvement*:** An assessment is made to determine what the total customer interruptions ("CI") improvement this project will achieve. To determine this, THESL reviews the average yearly total customer interruptions over the last two years that were caused by the assets intended to be replaced within the scope of the project.

- ***Total Customer Minutes Out ("CMO") Improvement*:** An assessment is made to determine what the total CMO improvement this project/program will achieve. To determine this, the average yearly total customer minutes out over the last two years that were caused by the assets intended to be replaced within the scope of the project is determined.

Risk Mitigation

This criterion considers six factors related to risk mitigation. The six factors are as follows:

- ***System Reliability – End of Life Assets*:** An assessment is made to determine the extent of improvement to system reliability with respect to end-of-life assets. THESL initially determines what the primary asset class addressed by this project is. Once this is done, an approximate age of the main primary asset class

addressed by this project is determined and this is reviewed against anticipated service life for the primary asset class.

- ***System Reliability – Overloading*****:** An assessment is made to determine the extent of overloading on the system. Specifically, it is determined how this project will alleviate existing overloading conditions.

- ***System Reliability – Operational Flexibility*****:** An assessment is made to determine the current and future state of operational flexibility. Specifically, it is determined how this project will improve operational flexibility primarily from the standpoint of the Power System Controllers.

- ***System Reliability – Low Probability High Impact Events*** **-** An assessment is made to identify low probability high impact events that would negatively affect system reliability. Specifically, it is determined how this project would mitigate the impact of a potential outage from such events.

- ***Public Safety***: An assessment is made to identify public safety issues within the scope of the project. Specifically, it is determined how this project would improve public safety.

- ***Environmental***: An assessment is made to identify environmental issues within the scope of the project. Specifically, it is determined how this investment would improve environmental stewardship.

THESL Personnel Safety

An assessment is made to identify THESL personnel safety issues within the scope of the project. Specifically, it is determined how this project would improve the safety of THESL personnel.

COMPENSATION

In an industry characterized by an aging workforce and the challenges of a tight labour market, THESL is faced with a potential turnover approaching 50 percent of its unionized workforce within the next ten years. At the same time, THESL has embarked on an aggressive plan to renew its aging distribution system. To manage this level of change in both its work program and workforce, THESL must position itself to attract, motivate and retain the talent that is critical to maintaining and renewing its distribution system. Retention is a particular concern, given that THESL is one of the few utilities with its own Trades School, possibly making its apprentices and graduates susceptible to recruitment overtures. With these market conditions, THESL's total compensation package and ability to offer a rewarding work experience must enable it to compete successfully for employees with the requisite skill sets.

The goal of THESL's overall compensation strategy is to secure a workforce that is skilled and capable of exceptional performance and commitment. Its workforce is comprised of unionized and non-unionized employees. CUPE Local No. 1 is the sole bargaining agent for over 75 percent of THESL's employees. The Society of Energy Professionals represents Engineers. Compensation for CUPE and Society employees is negotiated through the collective bargaining process. When negotiating wage levels, consideration has to be given to the complexity of THESL's Overhead and Underground distribution system and the diverse skill sets required to work within this system in a dense urban environment, as well as the competitive wage levels of the GTA market. Base salary is central to the compensation for unionized employees.

THESL provides its non-unionized employees (Executive, Managers and Management) with a total cash compensation package comprised of two elements: base salary and variable performance pay. To ensure market competitiveness and a cohesive, well-

performing workforce, THESL's compensation must recognize both superior business results and behaviours. THESL's performance-based philosophy ensures that rewards are appropriately aligned with strategic direction, vision, goals, and behaviours. It also ensures a system by which both employees and the organization can thrive and achieve success.

Benchmarking studies are conducted to determine the external competitiveness of compensation programs. These studies examine all elements of compensation to ensure that levels, form and mix of compensation are competitive for jobs of comparable scope/responsibility in the markets that THESL competes for talent.

The annual Base Salary budget includes base salaries (inclusive of annual increases, promotional increases, etc.) and is set based on information from the marketplace. It also factors in potential changes resulting from any planned adjustments to base salary policy for the coming year.

All Management employees are eligible for an annual variable pay award. Performance Pay targets are assigned to each job and/or salary grade and are expressed as a percent of the current year's base salary. This plan is intended to be variable and as such, provides for significant variability in award payouts to employees from year to year, reflecting differences in business and/or their individual performance. THESL's Variable Performance Pay plan is attached as Exhibit C2, Tab 1, Schedule 5.

The Variable Performance Pay Program is reviewed annually to ensure continued alignment with corporate direction. Performance in THESL is measured against a scorecard of key performance indicators ("KPIs") in each of four categories:

1) People – Safety
2) Finance – Operating Expense and Net Income

3) Operations – Distribution Plant Capital Program Completion, SAIDI and SAIFI
4) Customer – Call Response and Quality, Customer Satisfaction and Conservation Demand Management ("CDM") Program Attainment

Weightings for the scorecard and individual performance contracts differ by position and may change from year to year. Weightings refer to the percentage of the total direct pay award that will be paid based on achievement against the goals. Variable pay awards are based on a combination of THESL results and the employee's individual performance contract results. Target levels vary by level within the organization. Pay at risk increases as accountability for organizational results increases. This approach is consistent with competitive market practices.

Variable Performance Pay Plans are a critical component of total cash compensation in a competitive market that enables THESL to recognize performance results without increasing fixed costs through escalating base salary levels. It aligns employee performance with business priorities and rewards them for results that serve THESL's customers and contribute to its success.

For detail on THESL's total cash compensation, refer to the Compensation Study prepared by Mercer Human Resource Consulting provided in Exhibit C2, Tab 1, Schedule 3.

Table 1 provides a comparison, by employee category, of compensation totals and averages for 2006 to 2010.

Table 1: Employee Compensation

Number of Employees - Full-Time Equivalents (FTEs)					
	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Executives	6	10	10	10	10
Managerial	21	41	47	47	47
Management/Non-Union	137	291	294	298	298
Unionized	1187	1265	1312	1363	1354
TOTAL**	**1351**	**1607**	**1664**	**1718**	**1709**

**Excludes President and Vice-President of CUPE Local One

Compensation - Average Yearly Base Wage ($)					
	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Executives	184,242	171,234	178,136	185,262	192,672
Managerial	120,630	118,757	122,756	127,666	132,773
Management/Non-Union	86,573	89,198	91,665	95,279	99,126
Unionized	67,668	70,677	72,711	75,064	78,215

Compensation - Average Yearly Overtime ($)					
	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Executives	-	-	-	-	-
Managerial	-	-	-	-	-
Management/Non-Union	7,307	3,179	3,508	3,638	3,777
Unionized	10,157	6,583	7,081	7,162	7,483

Compensation - Average Yearly Incentive ($)					
	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Executives	50,143	87,038	74,817	77,810	80,922
Managerial	14,662	19,879	19,409	20,186	20,993
Management/Non-Union	4,721	5,058	7,446	7,734	8,044
Unionized*	3,396	4,890	7,497	7,723	8,015

*Unionized category - only include The Society of Energy Professionals

Compensation - Average Yearly Benefits ($)					
	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Executives	75,145	76,112	82,993	86,345	89,923
Managerial	43,489	40,983	43,721	45,830	48,098
Management/Non-Union	25,585	30,244	32,541	34,083	35,790
Unionized	19,359	25,545	25,560	26,621	27,987

Table 2: Total Compensation

Executives	Total Compensation ($)
2006 Historical	1,718,844
2007 Bridge	2,966,093
2008 Test	3,359,458
2009 Test	3,494,161
2010 Test	3,635,174
Managerial	
2006 Historical	3,813,150
2007 Bridge	6,968,573
2008 Test	8,736,636
2009 Test	9,103,064
2010 Test	9,487,604
Management/Non-Union	
2006 Historical	17,053,273
2007 Bridge	36,350,671
2008 Test	39,777,741
2009 Test	41,952,887
2010 Test	43,742,365
Unionized	
2006 Historical	115,407,520
2007 Bridge	130,170,375
2008 Test	138,459,344
2009 Test	148,536,751
2010 Test	154,184,990

BASIS OF PROJECTIONS

Employee Compensation, Pensions and Benefits

Total compensation costs are projected to increase by eight percent in 2008, seven percent in 2009, and four percent in 2010. The increases are mainly attributed to the yearly market adjustment/general increases for all fulltime employees and to an expected increase in headcount.

The projected benefit cost is based on analysis provided by Morneau Sobeco Ltd. utilizing our benefit carrier data. Accrual cost for post-employment benefits is based on the same actuarial analysis used to determine the liability reported in THESL's audited financial statements, assuming no changes to existing benefit programs; this data is effective January 1, 2005.

Pension contribution increases were attributed to higher base pay. OMERS contributions are based on all pensionable earnings (2007 contributions: 6.5 percent before YMPE[1] and 9.6 percent after YMPE).

[1]Yearly Maximum Pensionable Earnings

toronto hydro corporation

POLICY DOCUMENT

Compensation Policy	**Process Owner - Department:** Organizational Effectiveness
	Process Owner – Group/Responsibility Centre: Organizational Effectiveness
	Effective Date:
The most recent version of this policy can be obtained from Organizational Effectiveness	
The distribution of this policy is restricted to those persons the policy is applicable	

APPROVED BY	SIGNATURE	DATE
David O' Brien President & CEO		April 18/07
Ave Lethbridge Vice-President, Organizational Effectiveness		April 18/07
Wendy Howse Manager, HR Planning, Benefits & Compensation		April 18/07

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1 POLICY DOCUMENT INTRODUCTION

Defines a policy (relative to other types of documentation), policy contents and approach.

1.1 Policy Definition

A "*Policy*" reflects Toronto Hydro's position on issues and is something that must be adhered to by its employees. It provides interpretation for and influences decisions and actions. A policy differs from guidelines and procedures.
"*Guidelines*" recommend the way in which a procedure is executed or the way in which a condition is managed. Guidelines allow flexibility for employees to make decisions – a policy does not allow this flexibility.
"*Procedures*" are more detailed methods and activities established for the implementation of established policies. A policy is 'what' the company does or should do and procedures are 'how' it carries out the expressions of its policy. Detailed procedures are not described in a policy document.

1.2 Policy Contents

Among other things, a policy describes the objectives, scope, responsibilities and requirements that apply to the organization or departments that have been identified in a policy. A Toronto Hydro policy facilitates compliance with internal or external standards or requirements, to meet its operating objectives and reduce risks.

To be effective and to maximize user acceptance, a policy should be comprehensive yet easy to understand and it should be well communicated and easily accessible to the user community.

2 SCOPE

Describes which groups and/or activities this policy applies to and does not apply to.

2.1 This policy applies to:

- All Executive Level Positions in Toronto Hydro Corporation (THC) and Toronto Hydro Affiliates
- All Managerial Level Positions in Toronto Hydro Corporation (THC) and Toronto Hydro Affiliates
- All Supervisory and Professional Level Positions in Toronto Hydro Corporation (THC) and Toronto Hydro Affiliates

- **As at January 1, 2007-all Administrative Level Positions in Toronto Hydro Corporation (THC) and Toronto Hydro Affiliates are administered under a Step Progression based base compensation system.**

3 OBJECTIVES – PHILOSOPHY & PRINCIPLES

Describes the purpose of this policy ("why it was created") and the objectives ("what" is) to be achieved by this policy.

3.1 Toronto Hydro provides a compensation program that is performance-based and competitive in the markets where Toronto Hydro competes for talent.

3.2 Toronto Hydro is committed to attracting and retaining individuals who are capable of exceptional performance and dedication. The company compensation philosophy is an important tool for communicating performance expectations, improving productivity and rewarding employees for their contributions to the company.

3.3 We recognize that to ensure market competitiveness and a cohesive, well-performing workforce, our compensation system must recognize both superior business achievements *and* behaviours. Our performance-based philosophy ensures that our rewards are appropriately aligned with our strategic direction, vision, goals, and behaviours. It also ensures a system by which both employees and the organization can thrive. With a collaborative, results-focused approach, we can achieve market success.

3.4 The management compensation system used will be non-discriminatory in theory, application and practice.

4 POLICY

4.1 Total Compensation

Total compensation is comprised of two elements: base salary and variable performance pay. Base salary provides a foundation for the overall compensation arrangement as it is the basis for determining the value of the other compensation elements; Variable Performance Pay, Benefits and Pension. Variable Performance Pay is intended to reward employees for the performance of the business and their contribution to its success. When determining Pay competitiveness, Toronto Hydro examines both base salary and Variable Performance pay individually and together.

4.2 Pay Competitiveness

Toronto Hydro will conduct a compensation benchmarking study at least every 3 years to determine the external competitiveness of compensation programs. This study will examine all elements of compensation to ensure that level, form and mix of compensation is competitive for jobs of comparable scope/responsibility in the markets that Toronto Hydro competes for talent. As needed, Toronto Hydro may review the competitiveness of selected positions.

Individual jobs are assigned salary ranges/grades which reflect the range of competitive pay for positions of comparable scope/responsibility. Each salary range has a minimum, job rate, and maximum that is market competitive. The job rate is a fully competitive level of compensation and should be achieveable over time for solid performance.

Jobs are assigned to these grades based on an evaluation of the skill, effort, responsibility and working conditions as determined by the Hay Guide Chart Profile Method of Job evaluation.

Significant changes to a job's scope/responsibility may warrant a change in job grade and salary range; each of these cases is handled individually or as part of changes to an entire department/unit. All job evaluations are made without reference to the employee and their performance. Approval of the Business Unit Executive and the Vice President of Organizational Effectiveness is required for job evaluation to be conducted.

Minor changes in daily tasks or activities or a change in the volume of those activities typically will not affect the value of the work relative to the other jobs at Toronto Hydro; roles in these instances will not be considered for re-evaluation.

4.3 Performance Ratings

A single rating of performance is used for the two cash components of our Compensation Program. Each management employee (executive, managerial, supervisory, professional, excluding Engineers) will be assessed against a 5-point scale to determine his/her relative performance. (Refer to Compensation Program Guide for Toronto Hydro Corporation (THC) and Toronto Hydro-Electric System Limited (THESL).

This rating will be based on the employees total performance contribution for the year relative to others considering; performance against agreed performance goals and targets (Performance Contracts), demonstration of Toronto Hydro's core behavioural competences and any other extraordinary contribution in the performance year.

4.4 Base Salary

Each position within Toronto Hydro is assigned a salary grade and a corresponding salary range. Individuals should expect to progress through the salary range at a rate that reflects their relative performance and pay. Employees who are new to their role and/or are not yet fullly meeting the expections of the job may expect to be paid below the job rate. Over time however, employees who meet the job expectations should be paid at or around the job rate. Employees who exceed expections may over time, expect to be paid above job rate. At no time will an employee be paid outside of the approved salary range for the position. Each year, the employee's performance will be reassessed and a new rating assigned.

All management salaries (including Administrative) will be reviewed on an annual basis with salary increases approved and applied in March of the current year retroactive to January 1 of the current year.

Employees hired or new to management on or after October 1 of the current year will not be eligible for a management salary review for the current year process (e.g. hired on Oct 15, 2006; salary not eligible for review until January 1, 2008).

Salary range adjustments, when required, are made annually effective **January 1**. Adjustments are based on market data in addition to consideration of various internal factors (e.g., potential positioning in ranges).

In some years it may not be necessary to make any changes to policy or only make partial adjustments (e.g. increase at below market values) depending on circumstances and compensation philosophy.

4.5 Variable Performance Pay

All Management employees are eligible for an annual Variable Performance Pay award. Performance pay targets are assigned to each job and/or salary grade and are expressed as a % of the current year's base salary. Employees who are solid performers should expect to earn target awards in years when corporate and or affiliate performance meets target. However, this plan is intended to be variable and as such; employees should expect significant variability in award payouts from year to year reflecting differences in Business and/or Individual performance.

Annual Variable Performance Pay awards are based on the individual's performance rating in addition to performance against agreed Business (Corporate or Affiliate) Scorecard results. The weighting of individual, affiliate and/or corporate business performance will vary by role and/or salary grade. Individual performance impacts are based on the employees overall performance rating and not exclusively on the performance contract results. The impact of individual performance on Variable Performance Pay awards will vary within a range at the discretion of management to recognize the relative performance of the employee. (Refer to Performance Pay Guidelines for Toronto Hydro Corporation (THC) and Toronto Hydro-Electric System Limited (THESL).

4.6 Compensation Budget Considerations (Annual Salary Policy)

Annual Management salary budgets are usually prepared in June/July by Organizational Effectiveness in conjunction with Finance.

The budget determines the funds to be allocated annually for each cost centre for total compensation, which would include base salaries (annual increases, promotional increases, etc.) and Performance Pay.

Information from the marketplace may also be considered in budget preparation. The compensation budget also factors in potential changes resulting from any planned adjustments to base salary policy for the upcoming year.

Individual Performance factors will have some influence on potential budget numbers. At the time budget is prepared, these factors can only be forecasted therefore, initial budget estimates are based on expected or "target" performance considerations.

A separate budget is prepared for employee benefits.

4.7 Treatment of Base Salary in Promotion Situations

Increases may be granted when an employee is promoted to a job associated with a higher job rate (or at a salary range higher) than the current one.

A promotional increase up to 5% of an employee's current salary may be granted providing that the proposed salary does not exceed the new grade's salary job rate.

When the effective date of the promotion is less than three months prior to the planned base salary increase period, a combined base salary and promotional increase may be granted.

5 OWNERSHIP AND RESPONSIBILITIES

5.1 Newly hired Management employees cannot be offered a base salary at or above the job rate. If there is an exceptional requirement to hire person with a salary at or above the posted job rate, this would require approval from the Vice-President, Organizational Effectiveness.

5.2 Accountabilities for Review and Approval

5.2.1 VP, Organizational Effectiveness

- Ensures that the total compensation program is managed for consistency and equity
- Approves (in conjunction with President & CEO, THC, and/or President, THESL) all changes in organizational design prior to any process being initiated to implement the changes
- Approve any additions to the organization's workforce complement (in conjunction with the top executive from an organization/affiliate/business unit)
- Approves base salary increases associated with organizational change, promotions or other job movement
- Oversees the full compensation package being provided to the board's compensation committee

5.2.2 Manager, HR Planning, Benefits & Compensation

- Develops and maintains the salary ranges in accordance with competitive pay practices
- Reviews salaries annually to ensure that Toronto Hydro remains competitive with the market
- Evaluates all jobs (job evaluation committee comprising representatives from HR and senior line & corporate management is scheduled to convene in 2007)
- Reviews exceptions not included in the annual workforce plan or covered off by the terms of this policy (in conjunction with the Vice President, Organizational Effectiveness)
- Prepares and provides data/information/analysis to CEO, Executives, Sr. Management, etc. for standard and/or special compensation-related requirements (i.e. Board Presentations)

5.2.3 Manager, Organizational Development & Performance

- Oversees the Performance Management Evaluation & Reward systems
- Directs the annual performance contracting and evaluation process
- Develops and directs the engagement and communication process for compensation-related initiatives

5.2.4 Board of Directors

- Reviews recommendations made by the executive management team and will give final approval for the compensation system that will be used by the organization for Management employees
- Compensation Committee reviews and approves Executive Compensation tables, Performance Evaluation and Corporate KPI/Scorecard
- Audit Committee confirms all scorecard results and Performance Pay payout amounts

5.2.5 President & CEO, THC

- Presents Corporate results & Executive Compensation tables to Board Compensation Committee
- Ensures Toronto Hydro is staffed with highly qualified, fully competent employees and that all programs are administered within appropriate guidelines and within the approved budget

5.2.6 Other Executive or Sr. Management (i.e., THESL or Affiliates, CFO, Business Unit Management, etc.):

- Ensures adherence to the philosophy, principles and requirements as stipulated in this policy.

31 May 2007

Compensation and Benefits Competitiveness
Toronto Hydro Corporation

MERCER
Human Resource Consulting

MMC Marsh & McLennan Companies

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1

Introduction & Overview

Mercer Human Resource Consulting ("Mercer") has been engaged by the Management of Toronto Hydro Corporation ("Toronto Hydro") to complete a broad-based market pay review for positions within the Corporation. The purpose of this review is to assess the competitiveness of Toronto Hydro's compensation and benefits programs. In order to provide a comprehensive report, we have referenced market data and comparisons from other non-Mercer compensation and benefit studies completed over the past two years, as described throughout this report.

To complete its review, Mercer assessed the competitiveness of Toronto Hydro's current compensation programs. This review included an analysis of base salaries, bonus levels, benefits, and pension arrangements for bargaining and non-bargaining employees in all levels and major job families of Toronto Hydro.

This compensation study employed standard market analysis methodologies used by Mercer in conducting similar reviews for other organizations. Mercer's analysis relied upon current incumbent compensation data provided to Mercer by Toronto Hydro. The competitiveness of current practices included comparisons to a variety of external market sources including proprietary Mercer compensation surveys, market survey data provided to Toronto Hydro by HayGroup, published data on collective bargaining agreements and other data sources available to Toronto Hydro.

In addition to the compensation competitiveness benchmarking, Mercer also reviewed the Company's compensation philosophy. Over the past two years, Toronto Hydro has made a considerable change in its approach to compensation for management and professional employees, moving towards a market competitive pay for performance compensation model. While Mercer has not reviewed the effectiveness of the performance-based compensation philosophy, we can observe that these programs are consistent with market best practice.

Introduction & Overview (cont'd)

Section 2 of this report describes our general analysis methodology; the findings of our analysis are reported in sections 3, 4 and 5 of this report.

Summary Conclusions

Toronto Hydro's pay policy provides its non-bargaining unit employees with base salaries, annual performance pay (bonuses), and benefits including OMERS pension plan.

As is typical with market compensation reviews, market comparators for the non-bargaining unit compensation levels were selected based on a sample of national organizations with revenues comparable to Toronto Hydro. In order to facilitate a comparison to the non-utility sector, we have excluded flow-through revenues (i.e., the cost of electricity) from the revenue scoping to provide a comparison on a similar value-add basis. By doing so, the review excluded large companies whose compensation levels would have been significantly higher than those at the companies used in this review.

Overall, we note that Toronto Hydro's compensation and benefits plans are appropriately competitive; however, as outlined throughout this report, the competitive positioning relative to the market benchmarks varies by level within the organization. Due to upward pay pressures and legacy pay issues from the bargaining group, supervisory pay levels exceed market median levels. The management and professional levels appear to be positioned competitively against both the national and utilities markets. At the senior executive level, base salary and annual bonus levels fall below market median levels; when compared to total compensation levels, the lack of long-term incentives further positions Toronto Hydro pay levels below market median.

Toronto Hydro's pay policy structure is consistent and aligned with market. Incumbent pay levels within the structure are varied, which would be considered consistent with a pay for performance delivery model.

To compare Toronto Hydro's benefits offerings to market competitive levels, we referenced data from national industrial organizations, Ontario and national utilities and collective agreements. From the analysis, we determined that Toronto Hydro's benefits offerings are competitive with market practice.

Toronto Hydro employees participate in the OMERS pension plan. While this plan is consistent across all Ontario municipal utilities, we have compared its competitiveness to offerings from other municipal utilities located outside of Ontario.

Toronto Hydro's compensation policies and practices are appropriately competitive and well administered. The introduction of a pay for performance model has further aligned Toronto Hydro's compensation policy with corporate performance, and has moved the Company's policy closer to market competitive practice.

2

Market Analysis Methodology

This section outlines the methodology used to benchmark the competitiveness of Toronto Hydro's pay policy. For this review, we have benchmarked actual compensation, benefits and pension levels within the Bargaining Unit, the Society of Energy Professionals, and the Executive, Management and Professional employees of Toronto Hydro. Unless otherwise noted, the market compensation data was effective as of April 1st, 2006.

Mercer's methodology used for benchmarking cash compensation varies from that used to benchmark benefits and pensions. Cash compensation levels tend to be aligned with the scope and complexity of the individual position and, as such to the extent possible we have analyzed market data specific to the individual position. Benefit and pension programs tend to be common to all participants within a defined group and, as such the comparison to market is done on a plan or aggregate basis.

The goal of any competitiveness review is to map a reasonable sample of Toronto Hydro's positions to an appropriate competitive data source(s) and document the relative positioning and any misalignments. To accomplish this, Mercer considered a variety of data sources and made best efforts to map as many positions as practical to the market. To this end, Mercer compared approximately 65% of the executive, management and professional employees within Toronto Hydro to market sources.

Compensation for the bargaining group positions were benchmarked separately against collective agreements from national utilities. This analysis compared 12 key positions representing 47% of the Toronto Hydro's bargaining unit population to market sources.

Mercer notes that all of the survey sources used in this analysis were based on Canadian data only. We did not reference the US market as this would be beyond the scope of a typical market review; furthermore, we note that the US market typically exhibits different pay structures and practices than the Canadian market.

Market Analysis Methodology (cont'd)

Benchmark Summary

The following table highlights the various comparators/data sources used to benchmark Toronto Hydro's compensation programs.

Compensation Component	Data Source			
	Broad National Market	*Ontario Utilities*	*National Utilities*	*Collective Agreements*
Cash Compensation				
Executive/Management/Professional	✓		✓	
Bargaining Unit		✓		✓
Benefits				
Executive/Management/Professional	✓	✓		
Bargaining Unit		✓	✓	✓
Pension				
Executive/Management/Professional		✓	✓	
Bargaining Unit		✓	✓	

Cash Compensation

The following table provides an overview of the sample coverage used to conduct the cash compensation market benchmarking analysis:

Level		# Incumbents Per Level	# of Unique Positions Matched	# of Matches *(incumbents)*	% of Level Matched
Bargaining Unit Total		**1200**	**12**	**565**	**47%**
Administrative	A2 - B3	38	12	32	84%
Supervisory / Professional	CP1 - CP3	108	25	74	69%
	C1 - C3	108	23	57	53%
	DP1	17	3	14	82%
Management	D2	21	11	11	52%
	D3	18	7	7	39%
Executive	E1	5	5	5	100%
	E2	9	8	8	89%
	E3	2	2	2	100%
	F1	1	1	1	100%
	F2	1	1	1	100%
Non-Bargaining Total		**328**	**98**	**212**	**65%**

Market Analysis Methodology (cont'd)

Cash Compensation (cont'd)

It is Mercer's opinion that the samples outlined in the table on the preceding page are appropriate to assess the overall pay practices for employees and are generally representative of all major job specialties and organization levels within Toronto Hydro.

Non-Bargaining Unit

Cash compensation surveys are conducted annually by Mercer and other firms to provide data on a wide range of compensation practices in the market. The most typical methodology asks participating organizations to match their jobs to established benchmark job descriptions in the survey. Once a reasonable match has been identified, the participating organization then submits the current compensation levels (base salary, job rate, bonus award, target bonus, etc.) for all incumbents in the respective jobs.

In addition to compensation data, companies also provide specific organizational characteristics to enable Mercer to segment the survey results in order to create data samples that are relevant to the scope and complexity of the company being analyzed (i.e., Toronto Hydro). Typically, the data is segmented by industry when there is an adequate sample size, and by organization size, usually measured by revenue.

To provide an objective analysis, several data sources are often used to provide independent views of the market. We note, however, that these data sources represent different samples and methodologies so simple aggregation of the results is generally not appropriate.

When analyzing companies, the typical market practice is to consider companies that are one-half to two times the revenue of the target company (i.e., Toronto Hydro) – this range is generally considered an appropriate estimate of the scope and complexity of the organization. For purposes of this analysis, Mercer has reduced the overall revenue of Toronto Hydro for comparison purposes by the approximate amount of flow-through revenue. This reduced revenue scope better approximates the value-added of the business, and provides a conservative view of the pay market. For some positions that have accountability for total revenue, however, we do note that this reduced revenue range may understate the scope, i.e., finance, treasury positions.

For purposes of this analysis, non-bargaining group positions were compared to two data sources: i) National organizations with revenues between $250 million and $1.2 billion; and, ii) a sample of utility sector organizations from HayGroup. While we note that the competitive market for the majority of non-bargaining positions covered by this review is the national revenue scope, we have provided pay data for the Utilities sector to provide further context. To compare against the Utility sector, 12 benchmark positions were selected and compared (based on job content) against the 2006 Hay Utility Sector Compensation Survey, provided by HayGroup.

Market Analysis Methodology (cont'd)

Cash Compensation (cont'd)

Bargaining Unit

Bargaining Unit comparative data is provided from current collective agreements from organizations typically utilized as the basis for comparison at Toronto Hydro – these organizations are surveyed regularly by Toronto Hydro to capture the market data for specific positions within the bargaining group. These data include organizations where agreements have been recently ratified as well as contracts where new negotiations are underway or are expected in the near future. Our comparison includes data on 12 positions which represent approximately 47% of the bargaining unit work force; these positions are typical of benchmarks used within the industry to assess pay competitiveness.

Benefits

Benefit programs tend to be common to all employees in a participating group but the cost and value of the benefit to the employee can vary significantly by company and/or employee, depending on such factors as demographics and utilization rates. Furthermore, benefit survey databases are populated independently of cash compensation survey sources, so organizations' samples are not directly comparable to one another on a cost/value basis.

This analysis is intended to assess the reasonableness of overall benefit plan costs. Because specific benefits designs vary from company to company and because the costs of these plans are dependent on each respective company's employee base and utilization, Mercer developed a straw-model design and cost that would be typical of market practice, to facilitate the comparison of Toronto Hydro's specific plan design and costs to the market. Mercer compiled its straw-model design referencing the Mercer Plan Design Database which includes detailed benefit plan descriptions from 326 general industry organizations and 10 organizations from the Utilities sector.

Comparisons for this review included a broad comparison to the general market and a specific comparison to Ontario-based Utilities for executive, management and professional employees as well as bargaining unit employees within Toronto Hydro.

Market Analysis Methodology (cont'd)

Pension

We have been advised that all Ontario local distribution companies ("LDC") are required to participate in the OMERS pension plan. Therefore, the pension benefits provided to the employees of Toronto Hydro are consistent with the pension benefits provided to employees of other Ontario LDCs. Because participation in this plan is mandatory, this analysis focuses on the comparison of the attributes of the OMERS plan to offerings from other Canadian Utilities, as generated through our proprietary Mercer Pension Database. For purposes of this analysis, we have excluded the enhanced benefits provided to police and firefighters under the OMERS plan.

The Mercer Pension Database includes plan design information for Mercer clients, including 14 companies classified as being utilities. The information in this database is not available on a named basis in order to maintain confidentiality of the data.

3

Market Analysis Results – Cash Compensation

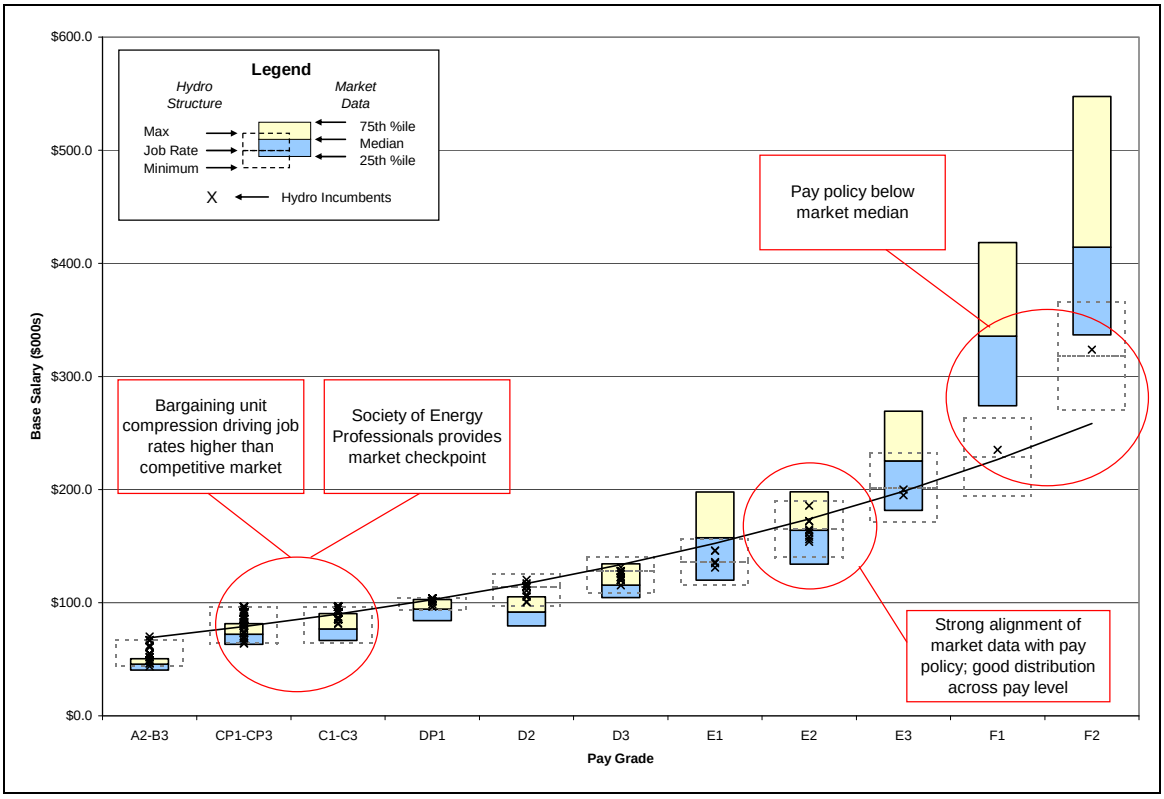
This section outlines the results of the market competitiveness review of Toronto Hydro's cash compensation levels. The charts which follow compare Toronto Hydro's actual market compensation and the pay range applicable to the salary grade for each position to the competitive market.

Market data reflects the range of pay practices for comparable roles. These data highlight the 25th percentile, 50th percentile (i.e., median), and 75th percentile market practices, unless otherwise noted. Specific variances to the market are highlighted on the applicable chart. The survey samples are segmented to reflect Toronto Hydro's size and complexity (i.e., revenue scope) accordingly. Fully competitive pay should approximate (i.e., within +/- 5%) the median of these samples.

Appendix A provides further details on the charts on the following pages, including a description of the components used to describe compensation.

Market Analysis Results – Cash Compensation (cont'd)

Base Salary

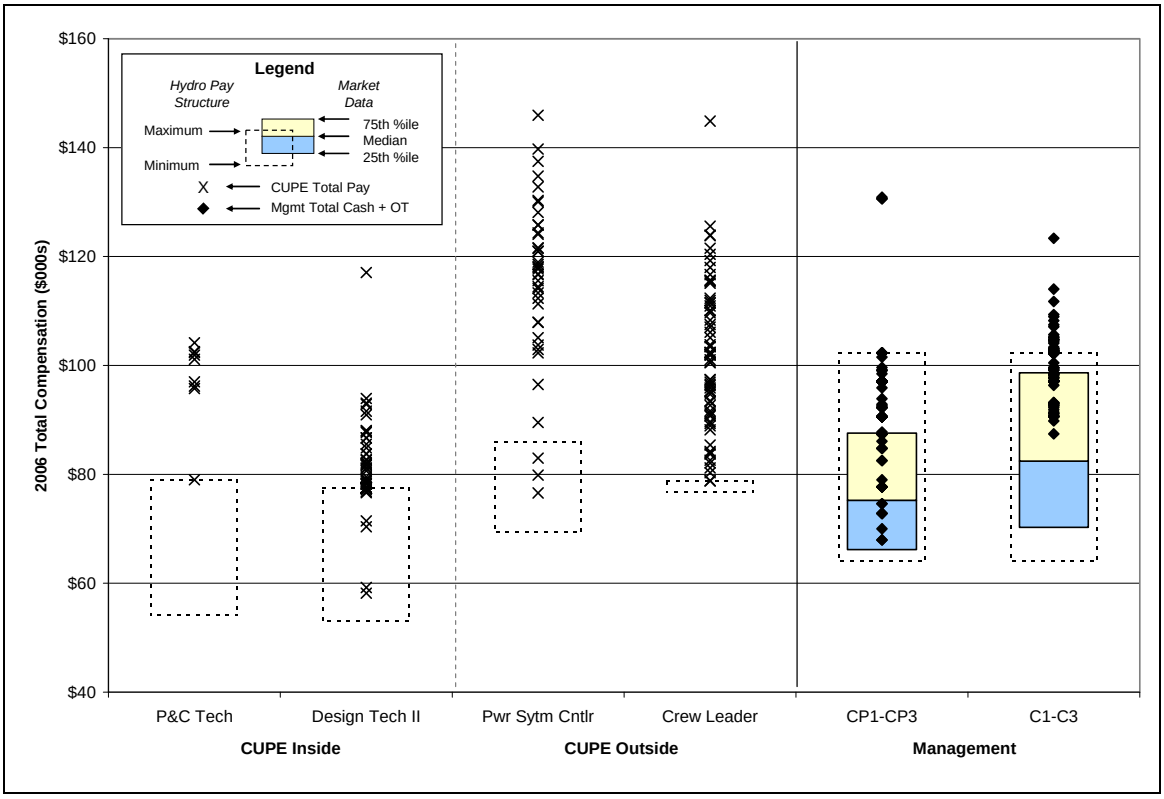


Commentary

- Pay levels at first-level supervisor levels (C-levels) are above market competitive levels due to compression from the bargaining unit – see following page;
- Society of Energy Professionals' compensation is negotiated with comparisons made to other Society roles within the utilities sector. This data becomes an external reference for internal pay equity at the supervisor/professional levels;
- Executive level E2 illustrates competitive and consistent market positioning – pay policy is closely aligned to market competitive data, and incumbents are distributed evenly across the level.
- Pay policy for Senior Executive levels (E3 through F2) falls short of market median levels.

Market Analysis Results – Cash Compensation (cont'd)

Bargaining Unit / Supervisory Compression Issues



Commentary

- The chart above outlines the compression issues facing Toronto Hydro at the supervisory level. 'Compression' describes the pressure placed upon the supervisor pay levels by the high pay opportunity at the senior bargaining unit positions.
  - The CUPE Inside and CUPE Outside positions above reflect the top levels within each bargaining unit, from which Toronto Hydro would typically draw potential supervisory candidates.
  - The data above outlines the regular pay policy for each position (hourly/weekly wage for 52 weeks) outlined by the dashed-line box. Mapped over these pay policy boxes are the total compensation levels, including overtime, for all incumbents within each position.
  - These bargaining unit pay levels are benchmarked against other public sector Collective Bargaining Agreements

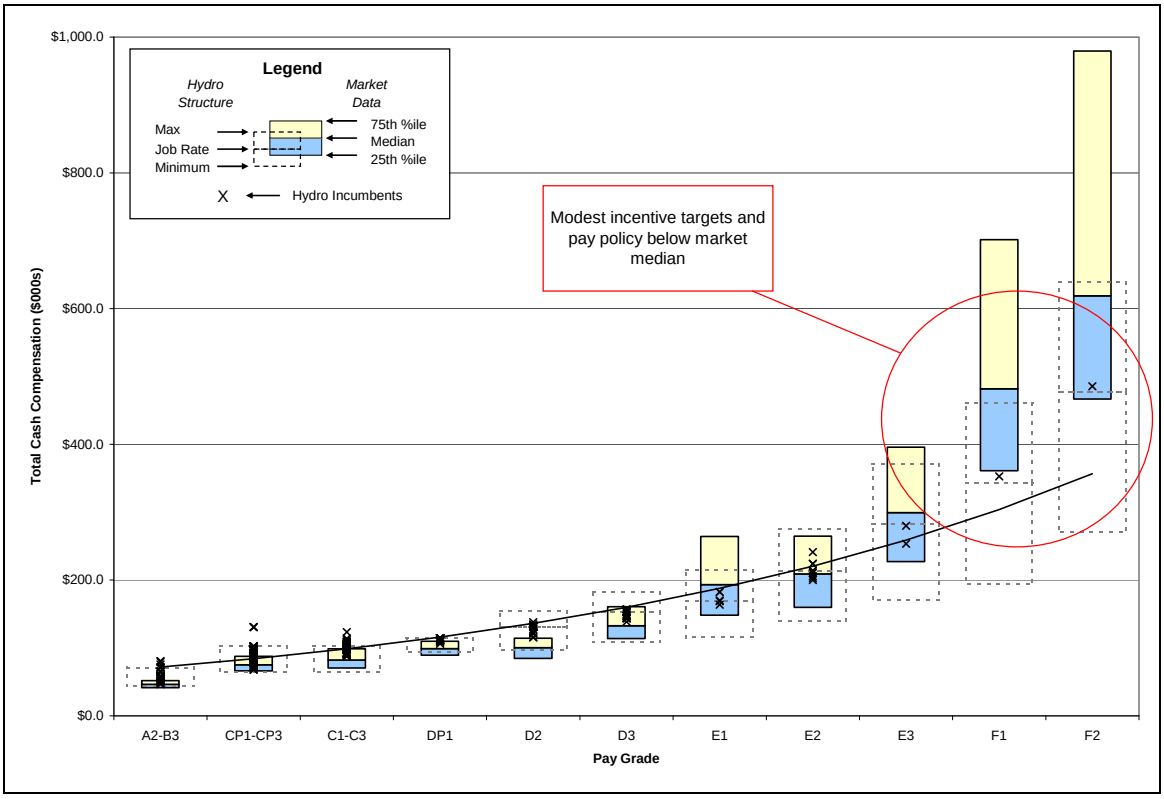
Market Analysis Results – Cash Compensation (cont'd)

Commentary (cont'd)

- The compression from these above-policy pay levels has driven the supervisory compensation to above market levels, as displayed on the Management side of the chart. This outcome is typical of organizations that have both bargaining and non-bargaining employee groups.
- We note that the total cash compensation level at the supervisory level is below the total cash levels of the CUPE outside and comparable to those of CUPE Inside.

Market Analysis Results – Cash Compensation (cont'd)

Total Cash Compensation

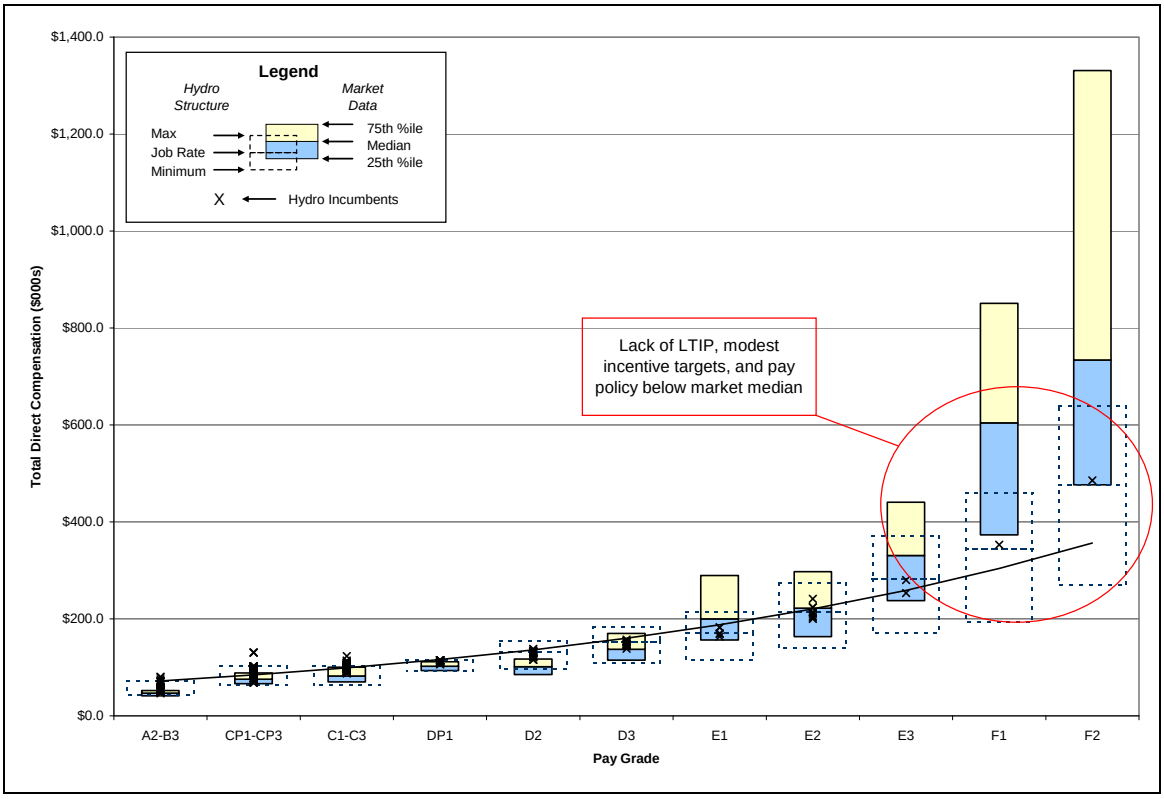


Commentary

- Total Cash Compensation = Base Salary + Actual Bonus
- The competitiveness of total cash compensation is impacted by both the competitiveness of base salary levels as well as the size of annual bonus awards.
- As noted, base salaries are more competitive at the professional/supervisory levels; as a result, overall total cash compensation continues to be above market.
- At the management level, overall total cash compensation is competitive with market.
- At the senior executive level, both base salary and annual bonus awards are below competitive levels.
- Although there is a shortfall at the senior-most executive levels, the introduction of the variable pay policy better aligns Toronto Hydro's pay with corporate performance.
  - Pay for performance was extended to supervisors and professionals in 2007.
- Bonus programs are found in over 90% of broad industrial organizations in Mercer's database. While bonus compensation is less common in the public sector, we note that the use of bonuses is becoming increasingly prevalent in the utilities sector.

Market Analysis Results – Cash Compensation (cont'd)

Total Direct Compensation

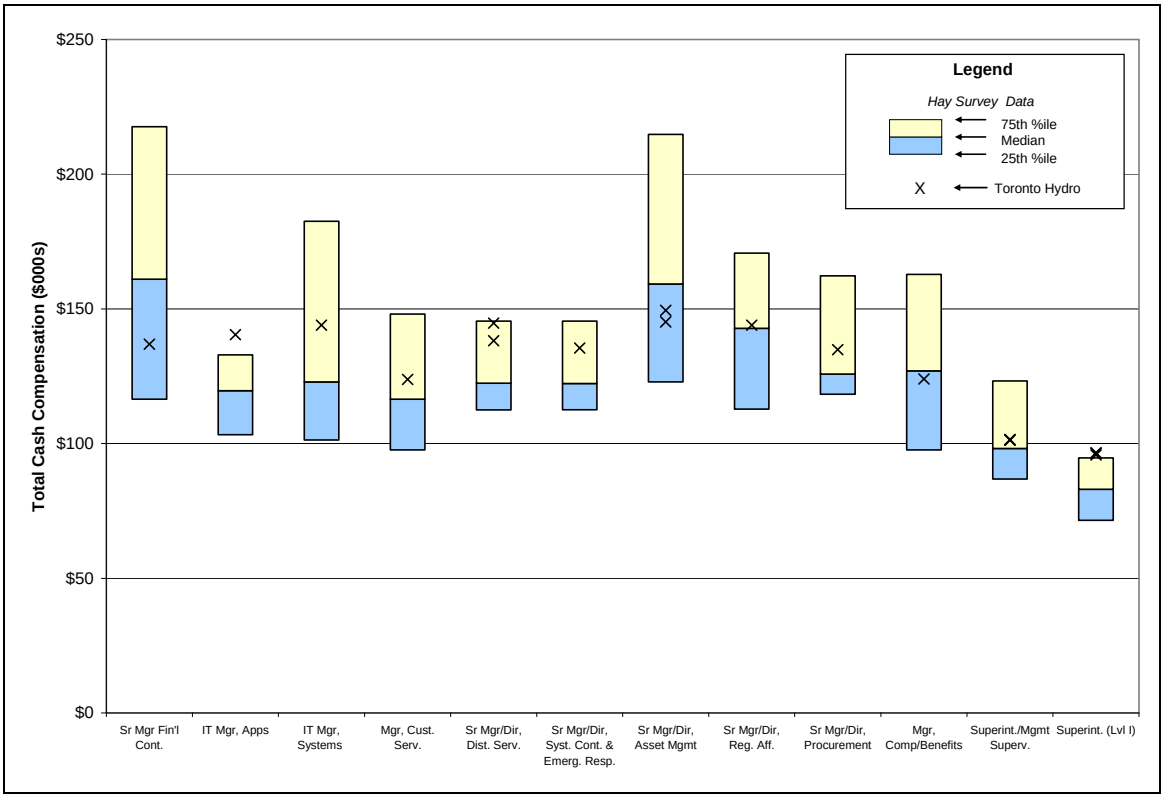


Commentary

- Total Direct Compensation = Base salary + Actual Bonus + Long-Term Incentives
- At the total direct compensation level (base salary plus all incentives), the pay gaps are increased due to the lack of a long-term incentive plan ("LTIP").
- For private sector companies, LTIPs are typical market practice at the executive level, and can represent a significant proportion of total direct compensation (e.g. 50%).

Market Analysis Results – Cash Compensation (cont'd)

Comparison vs. Utility Market Data

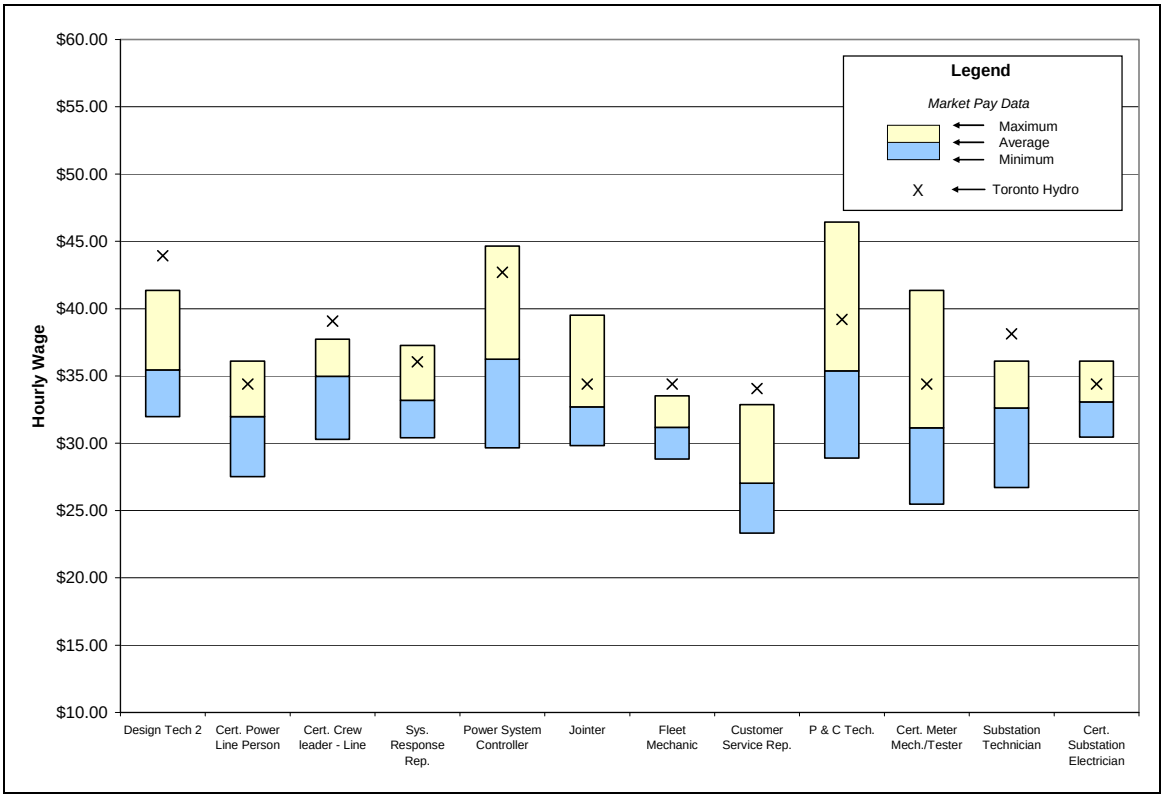


Commentary

- 12 management benchmark positions were compared to a survey of utilities sector compensation practices for organizations throughout Canada. This data was provided to Mercer by HayGroup.
- Generally Toronto Hydro total cash compensation levels are positioned competitively against the utilities sector.

Market Analysis Results – Cash Compensation (cont'd)

Comparison vs. CUPE Bargaining Agreements



Commentary

- For positions at this level, this market comparison is not adjusted for the size and complexity of individual jobs. Variance against the market is a function of collective bargaining and differences in the scope and complexity of Toronto Hydro jobs versus those in other bargaining groups. In addition, this analysis does not consider the impact of cost of living differentials.
- 12 benchmark positions were compared against similar positions within other utilities, based on pay levels determined through collective bargaining agreements.
- The sample of organizations (detailed in Appendix A) includes 14 utilities with CUPE bargaining units across Canada, and reflects a reasonable basis from which to compare the competitiveness of Toronto Hydro's pay levels.
- The positions chosen are those that are typically used in collective bargaining negotiations and reflect a robust sample of the bargaining unit positions within Toronto Hydro.
- Toronto Hydro pays above market average in all cases, and in 5 of the 12 positions, pays at the top of the market.

4

Market Analysis Results – Benefits

This section outlines the results of the market competitiveness review of Toronto Hydro's benefits, including tables outlining benefits costs as a percentage of payroll. Appendix B provides a detailed description of the assumptions and the methodology used to analyze the benefits data.

General Salaried Plans

The following table outlines the cost as a percentage of payroll of the Toronto Hydro benefit plans, segmented by Executive & Senior Management, Management & Professional, and Professional Engineers, as compared to the benchmark of general salaried plans.

	% of Payroll*		
	Toronto Hydro	Salaried Benchmark	Difference
Exec. & Sr. Mgmt	4.8%	4.2%	0.6%
Mgmt & Professional	6.6%	6.0%	0.6%
Engineers	6.1%	5.7%	0.4%

* Percentages rounded

The Toronto Hydro plans are slightly above market relative to general salaried plans.

Utility Market

The following table outlines the cost as a percentage of payroll of the Toronto Hydro benefit plans, segmented by Executive & Senior Management, Management & Professional, and Professional Engineers, as compared to the benchmark of plans for Ontario-based utilities.

Market Analysis Results – Benefits (cont'd)

Utility Market (cont'd)

	% of Payroll*		
	Toronto Hydro	Utilities Benchmark	Difference
Exec. & Sr. Mgmt	4.8%	4.2%	0.6%
Mgmt & Professional	6.6%	6.1%	0.5%
Engineers	6.1%	5.8%	0.3%

* Percentages rounded

The plans for employers in the utilities market are marginally more competitive than the most prevalent plan in the comparator sample.

Collectively Bargained Plans

The following table outlines the cost, as a percentage of payroll, of the Toronto Hydro bargaining benefit plan, as compared to the plans for bargaining unit employees for 12 utilities located across Canada.

	% of Payroll*		
	Toronto Hydro	Utilities Benchmark	Difference
Bargaining Unit	8.3%	8.1%	0.2%

* Percentages rounded

When reviewed against the comparator market, the overall plan offered to bargaining unit employees is slightly more competitive than the most prevalent plan in the comparator market.

Commentary

The actual cost of delivering benefits varies based not only on the plan design, but on the characteristics of the covered employee population, actual claims experience under each benefit plan, and administration fees charged by the benefits providers. For this reason, it is not practical to benchmark one employer's benefit cost to an actual average cost of a particular market comparator.

Market Analysis Results – Benefits (cont'd)

Commentary (cont'd)

Based on the analysis of the most prevalent plan provisions in the defined comparator groups, an estimated market variance was calculated and was applied to Toronto Hydro's cost profile. Given that the maximum calculated variance ranges from 0.3% to 0.6% of an estimated non-bargaining payroll of $33.5 million, we conclude that the Toronto Hydro plans for management and professional employees, while more competitive than those provided in the comparator market, are consistent with the range of benefits provided in comparator markets, and fall within a band typical of minor design differences. The total cost of benefits provided expressed as a percentage of payroll is reasonable.

Similarly, the plan for bargaining unit employees, while slightly more generous than the most prevalent in the comparator group, is consistent with the range of benefits provided in the comparator market, with a variance of 0.2% of an estimated payroll of $80.4 million.

5

Market Analysis Results – Pension

It is our understanding that all LDCs are required to participate in the OMERS retirement plan. Therefore, the pension benefits provided to the employees of Toronto Hydro are consistent with the pension benefits provided to employees of other Ontario LDCs.

Each of the main provisions of the OMERS plan, with the exception of the employee contributions and the average earnings period, would be considered market competitive or above market when viewed on a stand-alone basis. When taken in aggregate, we expect that the provisions of the OMERS plan would be considered above market due to the fact that often market plans include a mix of provisions with some above market and some below market characteristics. While on a provisions basis the OMERS plan may seem above market competitive levels, this generosity should be taken into account considering the higher than market contribution rate that employees are required to contribute towards this larger benefit. **Considering the characteristics of the OMERS plan and the employee contribution levels, we consider this plan to be at or slightly above market competitive plans for utility organizations included in the Mercer Pension Database.**

Examples of provisions under the OMERS that are above market include the following:

- Unreduced 66.67% survivor benefit for married members. While practice is mixed with respect to the survivor benefit provided for married members, the 66.67% benefit is at the top-end of the market with some companies providing a 50% benefit and other providing a 60% benefit. A 66.67% survivor benefit is the maximum survivor benefit permitted under the Income Tax Act (without a reduction to the pension). In addition, we expect that the provision of child pension under the OMERS plan would be considered generous when compared with other utility companies.
- Provision of a bridge benefit for members who retire prior to their normal retirement date. Less than half of the utility companies in our database provide a bridge benefit.

Market Analysis Results – Pension (cont'd)

- Cost of living adjustments of 100% of CPI both prior to retirement and after retirement (capped at 6% with a carry forward provision). Approximately 2/3rds of the utility companies in our database provide automatic post-retirement indexing, with many of the remaining 1/3rd providing ad-hoc adjustments. On average, indexing is less than inflation for many of the plans that provide automatic indexing.

The tables below include a detailed comparison of the main provisions of the OMERS plan to the provisions for the utility companies in the Mercer Pension Database. As mentioned previously, all comparisons are made without taking into consideration the OMERS provisions that apply to the police and firefighters.

OMERS(1)	Market Commentary
▪ Benefit accrual rate (prior to integration with government benefits): – 2% of final average earnings for each year of pensionable service (contributory benefit)	▪ 9 of the 14 comparator companies provide a contributory final average pension plan with an accrual rate of the same 2% of average earnings ▪ 2 of the 14 comparator companies provide a non-contributory final average pension plan with an accrual rate of less than 2% of average earnings ▪ 3 of the 14 comparator companies provide a hybrid defined benefit / defined contribution pension plan where a comparable accrual rate cannot be calculated from the available data **The benefit accrual rate is consistent with the comparator industry for contributory defined benefit pension plans**
▪ Employee Contributions – Employees contribute 6.5% of earnings up to the YMPE and 9.6% of earnings in excess of the YMPE	▪ Among the 9 contributory pension plans, all have employee contributions that are less than OMERS. **The employee contribution rate is higher than the comparator companies**
▪ Average earnings are based on: – highest five consecutive years	▪ 8 of the 14 companies use a three year averaging period ▪ 6 of the 14 companies use a five year averaging period **The current average earnings period of 5 years is at the lower end of the comparator industry**
▪ Pensionable earnings – includes all T4 earnings excluding overtime and some one-time lump sum payments	▪ 10 of the 14 companies include only base salary ▪ 4 of the 14 companies include base salary and at least some portion of bonus

(1) Excludes enhanced benefits provided to police and firefighters

Market Analysis Results – Pension (cont'd)

OMERS(1)	Market Commentary
▪ The normal form of pension is: – a lifetime pension with 66.67% of the pension continuing for the lifetime of the spouse, plus 10% for each dependent child (up to a maximum of 100%). – If member does not have a spouse when he/she dies, 66.67% of the pension continues to the eligible children for as long as they are eligible	▪ 3 of the 14 companies provide a 50% survivor pension to a spouse ▪ 5 of the 14 companies provide a 60% survivor pension to a spouse ▪ 3 of the 14 companies provide a 66.67% survivor pension to a spouse (OMERS category) ▪ survivor benefits cannot be determined for 3 of the 14 companies from the data available ▪ No information is available on the provision of child pension for the comparator companies **The unreduced 66.67% survivor pension at OMERS is at the top end of common practice and is equal to the maximum percentage permitted under the Income Tax Act. Although specific data on child pension is not available, the provision of child pension at OMERS is expected to be at the high end of the range.**
▪ There are no early retirement reductions for benefits commencing after 30 years of service or after 90 points, but members have to be at least age 55 (i.e. 10 years within normal retirement age). ▪ Otherwise, 5% per annum early retirement reductions from the earliest of age 65, 30 years of service and 90 points	▪ 12 of the 14 companies allow an unreduced pension to members with at least 90 points (three of these companies also require members to be at least 55 and two also require members to be at least 60) ▪ 12 of the 14 companies provide an early retirement reduction factor of 5% or less if conditions for unreduced pension are not met **The unreduced early retirement provisions at OMERS are in line with (to slightly above) the typical practice at the comparator companies.**
▪ Bridge benefits – 0.675% of average earnings (up to the average YMPE) payable to age 65	▪ 5 of the 14 companies provide bridge benefits to members who retire early ▪ Level of bridge benefits cannot be determined from the available data **Providing a bridge benefit puts OMERS at the higher end of the comparator companies.**

(1) Excludes enhanced benefits provided to police and firefighters

Market Analysis Results – Pension (cont'd)

OMERS[1]	Market Commentary
▪ Indexing – Guaranteed - 100% of CPI with a maximum rate of 6%. Excess of CPI over 6% is carried forward and applied in future years	▪ 8 of the 14 companies provide guaranteed post-retirement indexing ▪ 4 of the 14 companies have provided at least one ad-hoc post-retirement increase in the past five years ▪ 2 of the 14 companies do not index benefits ▪ of the 8 companies that provide guarantee post-retirement indexing – 2 provide indexing between 50% and 60% of CPI – 1 provides indexing between 60% and 75% of CPI – 1 provides indexing at 100% of CPI in excess of 3% – 4 provide indexing at 100% of CPI **Indexing at 100% of CPI and the carry forward provision for indexing put OMERS at the top end of the comparator companies. Based on inflation of 2% per annum, the average indexation for plans that provide automatic indexing (or target ad-hoc indexing), is 1.58%. This increase compares with 2.0% in the OMERS. Currently, low inflation is limiting the cost of indexing at 100% of CPI. However, the OMERS is subject to a larger risk and cost when inflation increases.**

(1) Excludes enhanced benefits provided to police and firefighters

Appendix A

Pay Competitiveness Analysis

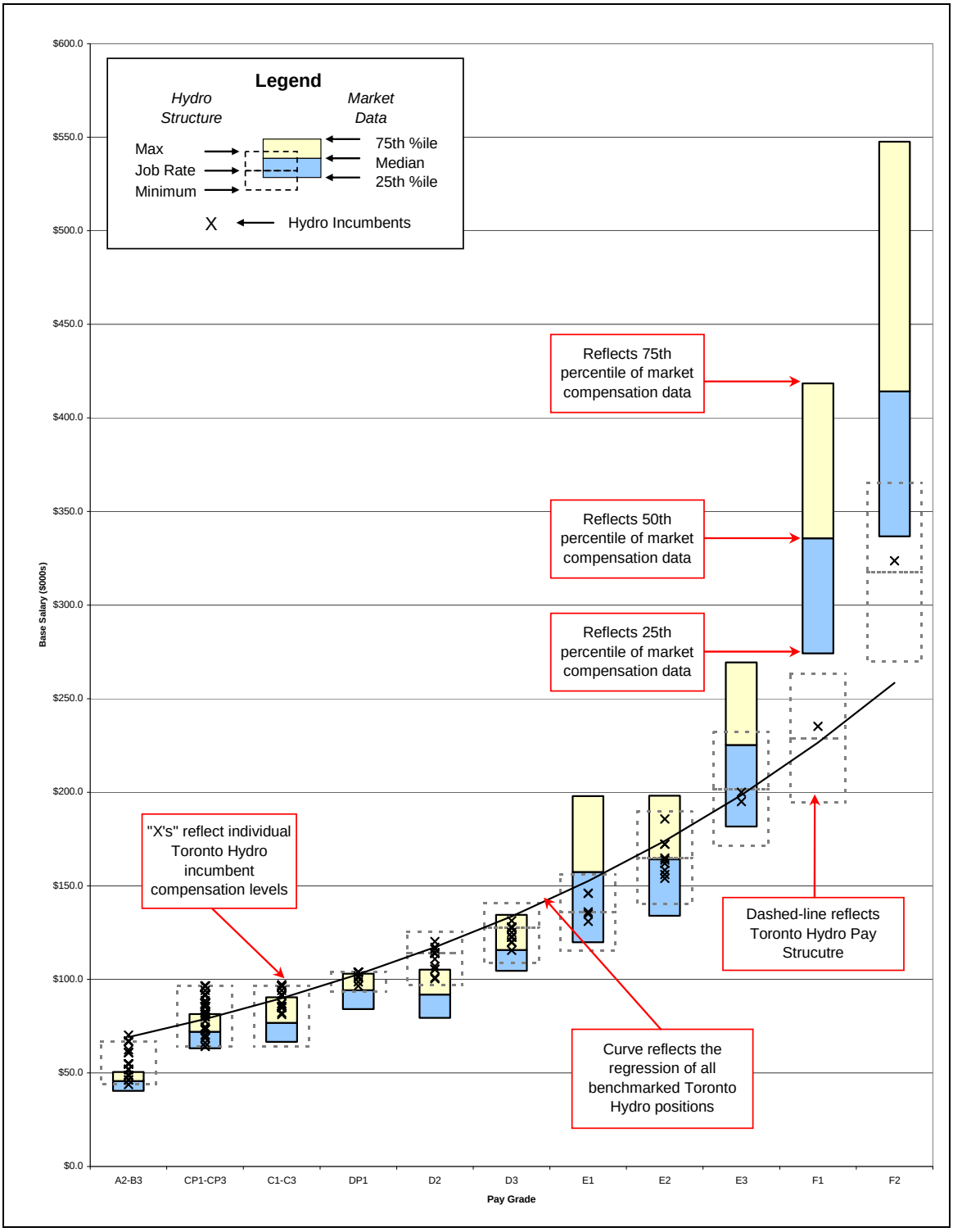
This section provides larger and more descriptive versions of the pay competitiveness charts displayed in section 3. In addition, we have also provided the list of organizations that the bargaining unit pay levels were benchmarked to.

The table below outlines the description of the various positions included in the analysis on the following pages:

Level	Description
A2 – B3	Administrative, Analysts
CP1 – CP3	Professional, Consultant
C1 – C3	Supervisors
DP1	Project Leaders, Team Leaders, Senior Consultants
D2	Managers
D3	Senior Managers, Directors
E1	Vice President
E2	Senior Vice Presidents
E3	Chief Financial Officer, Chief Operating Officer
F1	President THESL
F2	Chief Executive Officer

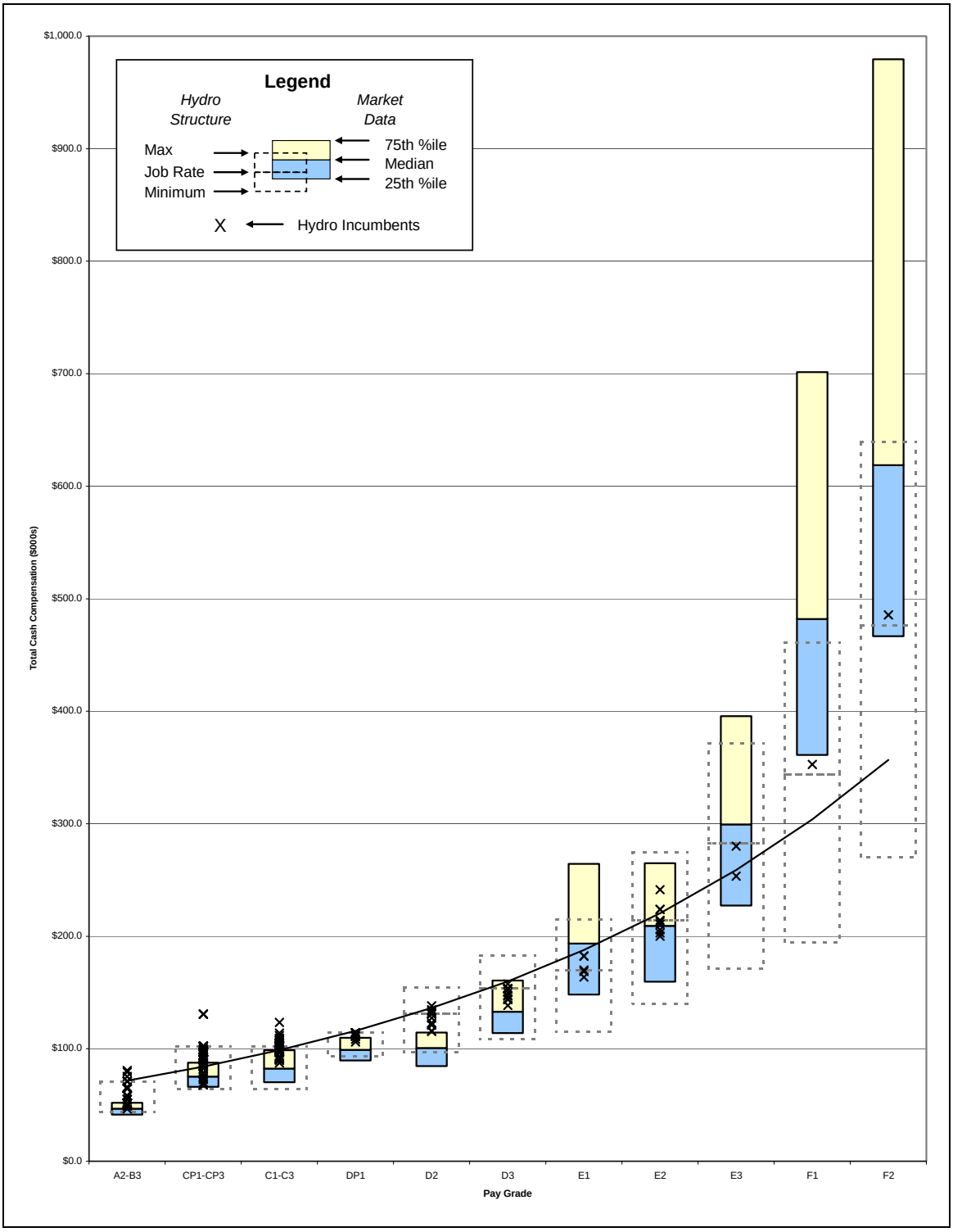
Pay Competitiveness Analysis (cont'd)

Base Salary *(with Graph Descriptions)*



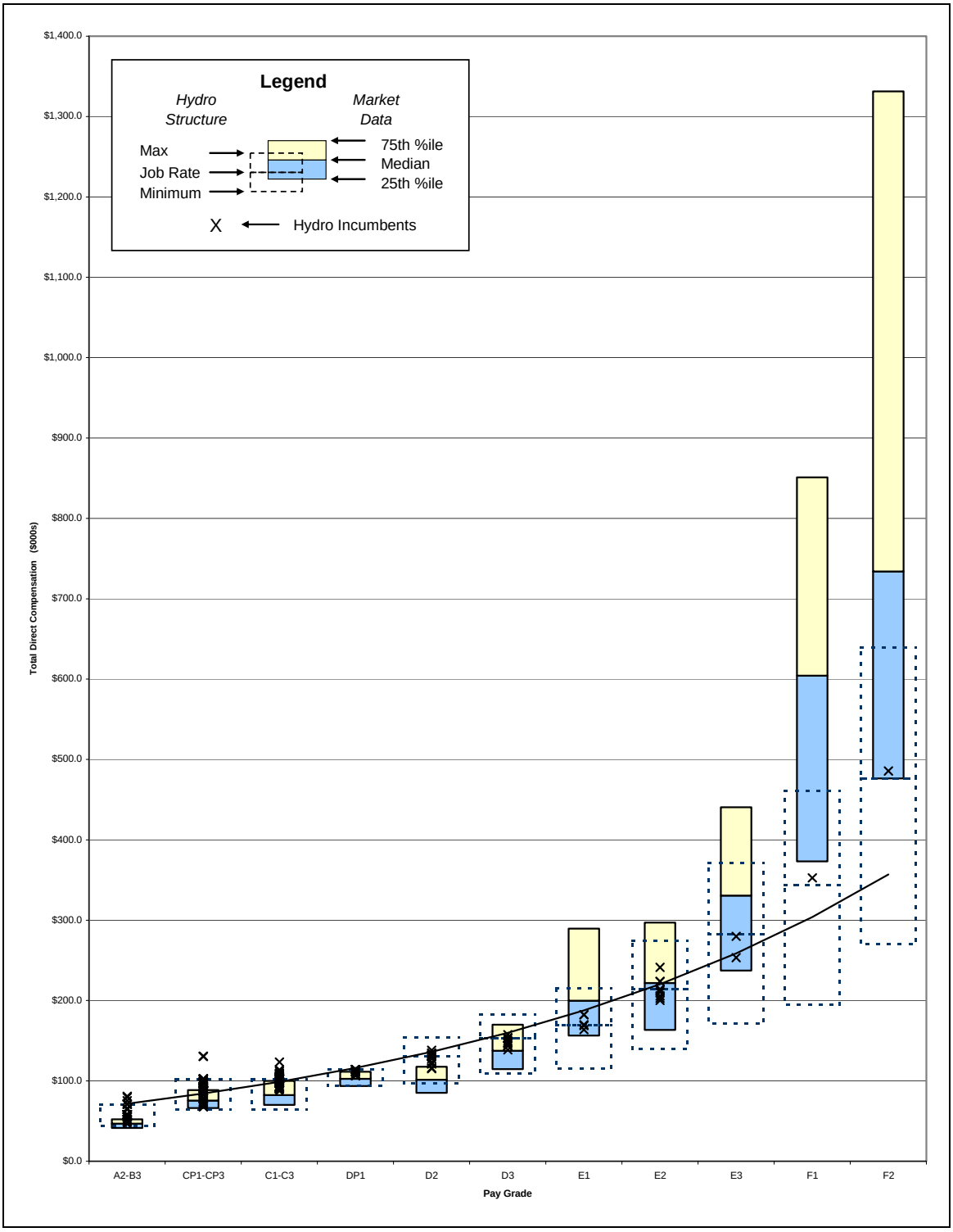
Pay Competitiveness Analysis (cont'd)

Total Cash Compensation



Pay Competitiveness Analysis (cont'd)

Total Direct Compensation



Pay Competitiveness Analysis (cont'd)

Bargaining Unit Comparators

The following organizations were used to benchmark the bargaining unit wages for 12 key positions:

Brampton (Hydro One)
Enbridge Gas Distribution
Enersource Corporation (Mississauga)
Enmax Corporation (Calgary)
Oshawa PUC
Veridian
Hydro One
Manitoba Hydro
Fortis
BC Hydro
New Brunswick Power
London Power
Horizon Utilities Corporation (Hamilton)
Hydro Ottawa

Appendix B

Benefits Assumptions and Methodology

Benefits Assumptions and Methodology (cont'd)

Data and Assumptions

Toronto Hydro benefit costs were calculated based on premium rates and deposits effective January 1, 2007. Payroll data and the number of employees were derived from data provided by Toronto Hydro. Annual earnings for Inside Bargaining Unit employees were based on weekly earnings multiplied by 52. For Outside Bargaining Unit employees, annual earnings were based on the hourly rates times 2080 hours per year.

To provide an appropriate context to benchmark Toronto Hydro's benefits, Mercer looked at different comparator groups as described below. The management and professional group's plans were compared to both general salaried plans, predominantly for Ontario employers, as well as utilities based in Ontario. Where slightly different plan provisions exist for Executives and Senior Management, and members of the Society of Energy Professionals, these differences were not taken into account since the number of employees covered under these plans and the plan differences are not material in the scope of this review. More material plan differences, such as higher life insurance coverage and health care spending accounts were taken into account.

Collectively bargained plans were compared to plans in place for bargaining unit employees in other utilities located across Canada.

General Salaried Plans

Our analysis was based on comparing the major benefit plan provisions for the Management and Professional benefit plans to the most prevalent plan provisions in the Mercer Benefits Database for general salaried plans. There are 772 salaried plans in the benchmark group.

Utility Market

While we note that the competitive market for the majority of positions covered by this review is the broad industrial marketplace, benefits are often differentiated based on industry sector. Therefore we benchmarked the management and professional benefit plans against Ontario based organizations in the utilities sector to provide further context to the competitive position of the benefit plans. There are 13 salaried plans in this benchmark group.

Collectively Bargained Plans

Toronto Hydro has two Collective Agreements with CUPE Local No. 1 representing Inside and Outside employees. We have compared the plans provided to these employees with other collectively bargained plans in place for 12 utilities located across Canada. The bargaining-unit benefit plans play a significant role in driving the plan design for non-bargained employees, with many plan provisions being common across all employee groups at Toronto Hydro.

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MMC Marsh & McLennan Companies

COMPENSATION

PENSIONS AND POST-RETIREMENT BENEFITS

Introduction

THESL's employees are members of the Ontario Municipal Employee Retirement Savings ("OMERS") Plan. The Plan is a contributory plan with employees contributing 50 percent of the premiums and THESL contributing 50 percent. Table 1 below presents the pension premiums, capitalized amounts and expensed amounts for the historical, bridge, and test years.

In addition to a pension benefit, employees also receive certain post-retirement benefits. Table 2 below presents the benefit costs, capitalized amounts and expensed amounts for the historical, bridge, and test years.

OMERS PENSION AND POST-RETIREMENT COSTS

Table 1: Pension Costs ($ Millions)

Pension	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Pension premiums	7.8	10.1	10.9	11.7	12.2
Less: Adjustments	2.5				
Less: amount capitalized	3.9	4.7	5.0	5.4	5.4
Amount expensed in each year	1.4	5.4	5.9	6.3	6.8

*Deferred to Regulatory Asset

Note: Beginning January 1, 2004, the Corporation returned to full contribution rates after a previous contribution holiday.

Table 2: Post-Retirement Benefits Costs ($ Millions)

Post Retirement Benefits	2006	2007	2008	2009	2010
Post Retirement Benefits Cost	14.1	14.6	14.5	15.4	15.8
Less: Amount capitalized	7.0	6.8	6.7	7.0	7.1
Amount expensed in Each Year	7.1	7.8	7.8	8.4	8.7

Post-Retirement Benefits Accounting Information

Current Accounting Treatment of Post-Retirement Benefits

Employee future benefits other than pension provided by THESL include medical and life insurance benefits, accumulated sick leave credits and voluntary exit incentive program liability. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefit expense is recognized on an accrual basis in the period in which the employees render services. The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on service and based on assumptions that reflect THESL's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period.

Treatment of Past Changes in Accounting Policy Regarding Post-Retirement Benefits,and any Related One-Time Expenses, Including Amortization Policy

There were no past changes in accounting policy or any related one-time expenses.

Treatment of Changes in Actuarial Value in Post-Retirement Benefits

Past service costs from plan amendments are amortized on a straightline basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains (losses) over 10 percent of the accrued benefit obligation are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in income in the year of the event that gave rise to the curtailment. The effects of a settlement gain or loss are recognized in income for the period in which a settlement occurs.

Disclosure of any Plans that do not follow the Current CICA Accounting Rules for Regulatory Purposes and Explanation for the Alternative Treatment

The post-retirement benefits disclosure is in accordance with CICA Handbook Section 3461 “Employee Future Benefits”.

2007 Performance Pay Guidelines

THC & THESL

Toronto Hydro-Electric System Limited
EB-2007-0608
Exhibit C2, Tab 1, Schedule 5
Filed: 2007 Aug 2

The Introduction

The Performance Pay Program reinforces Toronto Hydro's commitment to recognize and reward employee performance and contributions. The objectives of the program are to:

- Recognize employees for achievement of individual stretch goals, affiliate and corporate performance, beyond normal job functions
- Recognize productive employees contribute to cost containment and improving service to customers
- Ensure the performance pay award is fair and equitable relative to the contributions of others
- Motivate employees by rewarding both the results and the behaviours required to achieve our business goals

Eligibility

The program is effective January 1st, 2007 and **all Service and Administration (A & B level) management employees and professional engineers** (The Society of Professional Engineers) of **Toronto Hydro Corporation** (THC) and **Toronto Hydro Electric System Limited** (THESL) are eligible.

The program combines both individual performance and Corporate/Affiliate performance. Payouts differ by job level. The program is revisited on an annual basis, and may be modified, at the discretion of the Executive.

Annual Process	
November/ December	• Set performance pay award percentage for next fiscal year. • Complete current year key performance indicators (KPIs) audit and review.
January	• Set individual performance contracts for current year. • Send estimates of performance contract results to Organizational Effectiveness (OE) for preparation of payouts. • Set Corporate/Affiliate threshold, target, and maximum goals for current year.
February	• Organizational Effectiveness (OE) calculates performance pay allocations.
March	• THC CEO advises Compensation Committee and the Board of Directors of overall results. • Payroll is advised of step increases and performance payouts.
July	• Leaders complete mid-year discussions with employees to review individual performance, including opportunities for development and career goals.

2007 Scorecards

Performance is measured against a scorecard of key performance indicators (KPIs) in each of four categories – People, Finance, Operations, and Customer. The KPIs provide important organizational measures and targets that will focus performance discussions between leaders and employees. Refer to the appendix to this guide for 2007 scorecards for THC and THESL.

Performance Weightings by Position

Weightings for Corporate/Affiliate scorecards and individual performance contracts differ by position and may change from year to year. Page 3 illustrates the 2007 Weightings by position. Weightings refer to the percentage of the total direct pay award that will be paid based on performance against the goals.

2007 Performance Pay Guidelines

THC & THESL

2007 Weightings

Position	Individual Performance (%)	Affiliate Performance (%)		Corporate Performance (%)
CEO THC	20			80
President THESL	20	80		
COO, Executives THESL	40	60		
Executives – CFO, VP Organizational Effectiveness, VP Environment Health & Safety THC/THESL	40	THESL 35	THESI/ THTI 5	20
Managers THC	70			30
Managers THESL	70	30		
Supervisors and Professionals THC	80			20
Supervisors and Professionals THESL	80	20		
Service and Administration THC	90			10
Service and Administration THESL	90	10		

Performance Pay Award

Your performance pay award is based on a combination of Corporate/Affiliate results and your individual performance contract. The final payout will depend on the achievement weight of the Corporate/Affiliate scorecard and your individual performance contract results.

In 2007, the Corporate/Affiliate scorecards include threshold, target and maximum awards.

Threshold Performance	The minimally acceptable level of performance necessary to earn an incentive award.
Target Performance	The expected level of performance.
Maximum Performance	The demonstration of superior performance that exceeds expectations.

Corporate/Affiliate Performance

Threshold	**=**	25% of weighted target award
Target	=	100% of weighted target award
Maximum	=	150% of weighted target award

Example
We have provided an example below to illustrate how this works:

Salary for THC Employee	**=**	$50,000
Percentage Eligibility	=	6% of $50,000 = $3,000
% Weighting	=	90% Individual Performance, 10% Corporate/Affiliate Performance 90% = $2,700 10% = $300

If 80% of the performance contract is achieved and the Corporate/Affiliate Scorecard exceeds target and the overall scorecard result is 105%, than the payout would be calculated as follows:

Performance Contract ($2,700 x 80%)	$2,160
Corporate Plan ($300 x 105%)	$315
Total Payout	**$2,475**

Appendix

Scorecards 2007

Following are the THC and THESL Scorecards.The KPIs provide important organizational measures and targets that will focus our performance discussions. The scorecards will be the framework used to report overall performance under the categories of People, Finance, Operations, and Customer.

2007 THC Scorecard				
KPIs	**Weight**	**Threshold**	**Target**	**Maximum**
People				
Safety - My Goal is Zero *% of people achieved zero*	15%	93.4%	94.4%	95.4%
Finance				
Consolidated Operating Expense *$ millions*	20%	$215.5	$210.5	$205.5
Consolidated Net Income *$ millions, exluding sale of Water Heaters*	20%	$51.6	$56.6	$61.6
Operations				
Distribution Plant Capital Program Completion *$K per work unit completed*	15%	$1.76	$1.25	$1.00
Customer				
Call Response and Quality *Index; not including impact of TOU*	10%	70%	80%	85%
SAIDI *average outage minutes per customer*	10%	82.0	78.0	74.0
SAIFI *average # outages per customer*	10%	2.4	2.2	2.0
	100%	*25%*	*100%*	*150%*
			Payout Ratios	

2007 Performance Pay Guidelines

THC & THESL

2007 THESL Scorecard

KPIs	Weight	Threshold	Target	Maximum
People				
Safety - My Goal is Zero *% of people achieved zero*	10%	93%	94%	95%
Safety - EUSA Zero Quest *% Attainment of Level 3*	5%	70%	80%	90%
Finance				
Operating Expense *$ millions; not incl CDM*	20%	$181.1	$176.1	$171.1
Net Income *$ millions*	20%	$52.0	$57.0	$62.0
Operations				
Distribution Plant Capital Program Completion *$K per work unit completed*	25%	$1.76	$1.25	$1.00
SAIDI *avg outage minutes per customer.*	5%	82.0	78.0	74.0
SAIFI *avg # interruptions per customer*	5%	2.4	2.2	2.0
Customer				
Call Response and Quality *Index; not including impact of TOU*	10%	70%	80%	85%
Customer Satisfaction *establish benchmark*	0%	NA	Q3	NA
CDM Program Attainment	0%	80%	90%	100%
	100%	*25%*	*100%*	*150%*
			Payout Ratios	

2007 Performance Pay Guidelines

THC & THESL

A note about performance pay and employment status:

- Employees must be on the payroll as of December 31st, 2007 for eligibility. Payouts are based on your salary as of December 31st, 2007. Consideration is given to employees who have retired during the year.
- For employees who are promoted or transfered during the year, the award is pro-rated. The pro-rated calculation includes the number of months in the new position. The actual payout is weighted accordingly and reflects the target payout for each position.
- Leaders are accountable for submitting performance contracts for all new hires, employees on probation, or employees joining their department.
- For employees who retire, become disabled, or die during the year, a pro-rated payout is calculated based on the number of months worked in the position. Payouts are made at the same time as all other management employee payouts.
- For employees who are on sick leave or maternity leave for the entire year, no payout occurs in respect of that year. For employees who are on extended sick leave or maternity leave for only part of the year, a pro-rated payout is calculated. If an absence is less than three months, some discretion may apply.
- No payouts will occur for voluntary resignations or terminations with cause during the year.

A note about base pay increase:

- The hire date for employees to be eligible for a base pay increase is before September 30th, 2007.

Worth Mentioning:

- *Your leader may use discretionary ranking to assess the attainment of your individual objectives.*

Payouts will occur in March.

Checklist

- Performance contract completed and submitted by January 31st, 2007.
- Performance contract includes S.M.A.R.T (Specific, Measurable, Achievable, Relevant, Time-bound) objectives, stretch goals and a development plan.
- Mid-year discussion with your leader/employee to discuss objectives and performance expectations completed and submitted by July 31st, 2007.
- Year-end appraisal completed by January 31st, 2008.

COMPENSATION

WORKFORCE STAFFING PLAN

Over the next ten years, THESL will be faced with two critical challenges that are inextricably linked – an aging workforce and the need to renew its distribution system.

Aging Workforce

An aging workforce is not unique to THESL and is one of the most significant human resource issues facing the electricity industry in planning for future skill and competency requirements. Although companies have always had to respond to employees leaving the workforce through retirement, the magnitude and impact of projected retirements by the baby-boom generation far exceeds the industry and THESL's turnover experience[1].

The 2004 Canadian Electricity Association ("CEA") Human Resource Sector Study reported: "Employers indicated that over 17 percent of the 75,000 existing workforce [in the electricity sector] will be eligible for retirement in the next five years, and 37 percent of the workforce will be eligible to retire by 2014. Based on retirement estimates, the sector will need 9,000 people in technical positions in the next five years and more than 17,000 over ten years."

With the amalgamation of the six municipal utilities of Scarborough, York, East York, Toronto, North York and Etobicoke in 1998 into THESL, workforce adjustments were required to achieve economies of scale. To reduce staffing levels without lay-offs or forced job cuts, voluntary separation and retirement programs were offered in 1998 and 2001. These programs did not safeguard specific jobs or skill sets, nor did they target specific employee or job groups. Instead, these programs were made available to all employees of THESL. As a result, the number of employees employed by the former six

[1] The baby boom generation encompasses people born between 1945 and the early 1960s.

utilities was reduced from approximately 2,400 to 1,700 post-2001, comprised of employees who chose to remain with THESL and/or successfully competed for positions within THESL. Although the resulting staffing level and mix of competencies were adequate in the intervening years, the anticipated departures stemming from the aging workforce will create a shortfall in jobs and critical skill sets.

Retirement Projections

The current demographic profile of THESL indicates an average age of 49. Historically, the average retirement age of a THESL employee is 59 years of age. Predicting when an individual will retire is challenging, given that it is a personal decision dependent on many factors including financial, family, and health considerations. Nevertheless, for THESL's projected retirements in the current rate application, the average historical retirement age was used in combination with eligibility for an unreduced-pension-under-OMERS criteria. These criteria stipulate that a member must be a minimum of 55 years old with 30 years of service or a combination of minimum age 55 and years of service totalling 90 (90 Factor). With these conditions and OMERS' Normal Retirement Age 65 as the basis for the retirement projection, THESL estimates that 567 employees will retire from 2007 to 2016. See Table 1 below for the forecast of retirements out to 2016.

Table 1: Forecast Retirements

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	TOTAL
Number of retirements	24	18	34	46	50	60	72	88	75	100	567

These 567 employees represent approximately 35 percent of THESL's workforce. However, over 50 percent of the potential retirements will occur in supervisory, trades and technical positions. The substantial impact of retirements is expected to begin in 2010.

Asset Renewal Program

Over the next ten years, THESL will embark on a plan to modernize its infrastructure. A skilled and knowledgeable workforce is critical for THESL to be able to undertake its asset renewal program while continuing to meet customers' expectations for reliable and responsive service. Due to the retirements of the aging workforce anticipated in the next three to five years, there is a pressing need to hire and train skilled workers. At the same time, THESL will require excellent leadership to maintain and improve performance during this extended period of flux as employees of varying levels of knowledge and experience work alongside experienced workers, critical knowledge is transferred and the renewal plan increases work demands.

To support the ramp up of the asset modernization, skills requirements will focus on trades and technical jobs. Overhead and Underground trades as well as Designers and Engineers will comprise the core of this workforce. Critical strategic competencies of expert planning, risk management and leadership will be key to sustaining operational excellence during this period of accelerated system refurbishment.

Staffing Strategy

With the expected retirement of 567 employees from THESL's workforce from 2007-2016 coinciding with the need to add staff to deal with a major increase in capital work, THESL's staffing strategy is to leverage the attrition opportunity by focusing on replacing and augmenting trades and technical jobs. Additionally, selective replenishment of other jobs will be required to meet business needs, consistent with the normal course of business. Over 65 percent of the hiring from 2007 to 2010 will be in trades and technical jobs. Those jobs include Designers, Engineers, Overhead and Underground trades. Retirement experience will be monitored during this period, along with achievements in performance improvement. These results and any changes to

business needs will be used to recalibrate hiring requirements in the years following 2010.

Trades and Technical Jobs

Twenty-eight per cent of THESL's workforce consists of trades and technical jobs. Although the aging workforce cuts right across the business, the primary focus of the workforce staffing plan is to deal with these specific roles. These roles are the focus because of the critical nature that they play in the safe and reliable design, construction and maintenance of THESL's distribution system.

The profile for these jobs in THESL places their average age at 48. This age profile is higher than the Canadian Labour force profile. Based on Statistics Canada data published on their website, 52.9 percent of the labour force is 45 years or older. This demographic profile, coupled with forecast labour and skills shortages suggests there will be fierce competition for these skills in the labour market in the future, particularly for these jobs. Attracting fully competent trades and technical resources will be a challenge. The internal and external labour conditions and THESL's capital plan requirements create an exceptional and compelling need to address its workforce capabilities in the immediate future.

Replenishing Trades and Technical Jobs

To replenish the skills shortfall created by exiting employees, external recruitment of fully competent workers cannot be relied on given the forecasted labour market shortages. THESL's plan is to hire experienced workers when available, along with new entrants as apprentices to trades and technical positions. THESL will build on its trades training expertise and invest in a three- to five-year internal training plan or apprenticeship program, with the expectation that trades apprentices will require up to five years to become fully competent and capable of performing all aspects of the job.

This approach is not without its own challenges related to retention. It is anticipated that these employees will be highly sought after both while in training and even more so, once they have achieved proficiency in their trade or skill.

In 2003, THESL initiated a Trades School within THESL because the basic training that new hires had received externally was insufficient to maintain safe and efficient operations and satisfactory customer service in such a complex distribution territory. Between 2003 and 2005, THESL hired 24 trades apprentices (Certified Power Line Persons, Jointers, Substation Technicians, Power Cable Persons) and technical apprentices (Design Technicians, Engineers, Power System Controllers). At the end of 2006, THESL had 38 trade apprentices. From 2007 to 2010, THESL expects to hire approximately 128 Trades apprentices. As noted in Table 2 below, in 2007, the apprentice-hiring plan includes the hiring of trades and technical apprentices, as well as graduation of trades apprentices. From 2008 to 2010, approximately, 14 Design Technicians, 8 Substation Technicians, 3 Engineers, 2 Substation Designers, and 3 Power System Controllers will be hired. For a Trades apprentice to graduate they need to complete 8,000 hours of Underground and Overhead line work, which usually takes four and a half years.

Hiring Plan for Trades and Technical Jobs

Table 2: Apprentices staffing plan

Description	2003-2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Trades	38	74	96	144	129
Technical	9	12	11	14	6
Graduating	1	5	18	0	15

The increase in hiring of apprentices is attributable to the lead-time required to respond to the anticipated retirements and the increased asset investment. THESL requires some overlap between experienced and newly hired employees to ensure sufficient skills development of the entrants and knowledge transfer between these two groups. THESL also must deliver on a much larger capital program in the three test years.

Staffing Plan Costs

Table 3 illustrates the total cost of the Apprenticeship Program. These costs include trades apprentices in a 4 ½ year apprenticeship. From 2008 to 2010 the headcount listed below is for all trades apprentices in the program.

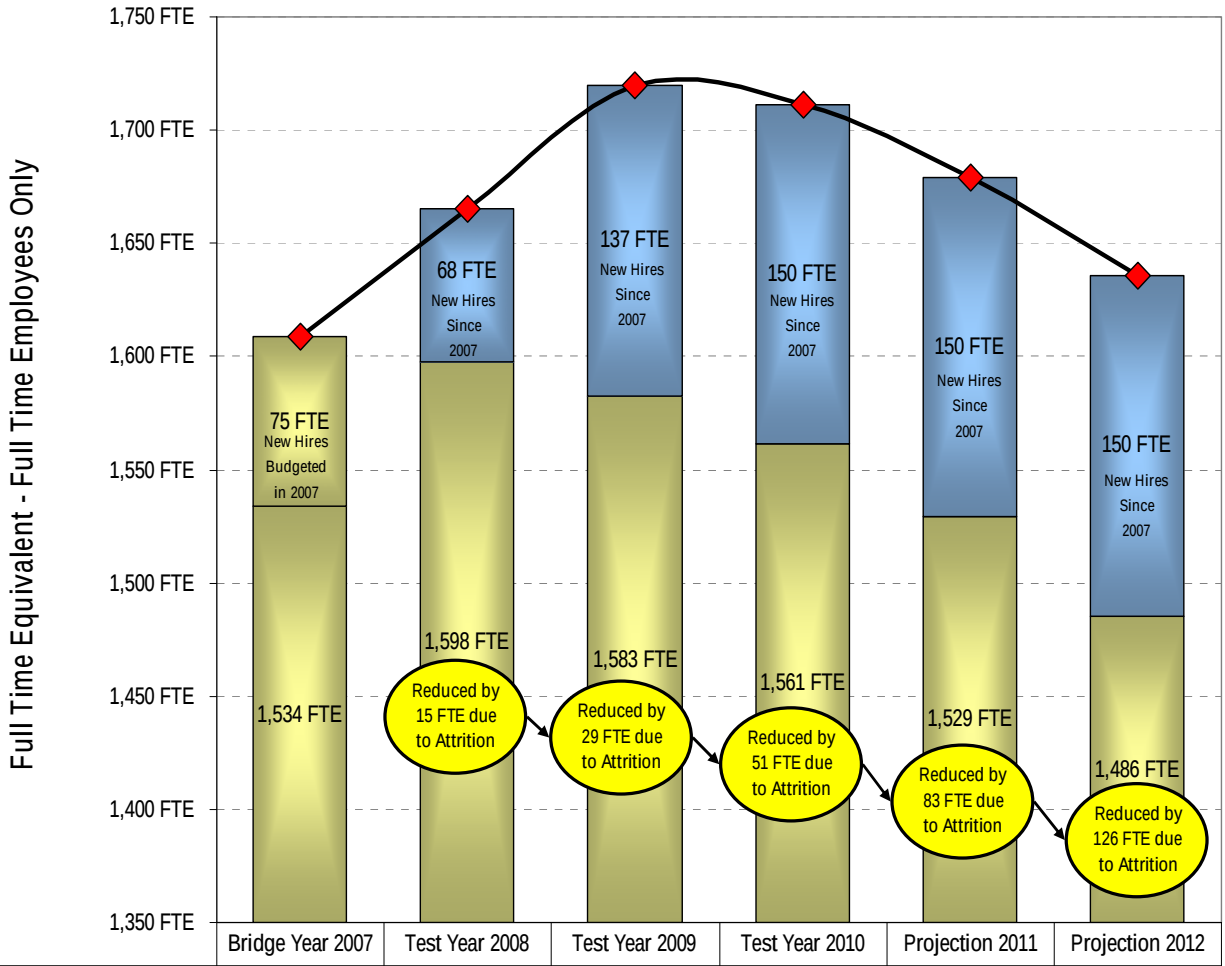
Table 3: Headcount and Costs

Year	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Total Headcount Year End	38	74	96	144	129
Cost ($000s)	720	1,728	1,635	2,209	2,408

The cost increase from 2006 to 2007 is attributable to the increase in the number of apprentices and the increase in union wages. From 2007 on, the increases are based on the number of apprentices and assume a 3.5 percent increase in union wages.

Table 4 below illustrates the accelerated hiring from 2007 to 2010 to meet the demands of the asset renewal plan and the impact of attrition after 2010 when hiring returns to normal levels.

Table 4: THESL Staffing Projection



	Bridge Year 2007	Test Year 2008	Test Year 2009	Test Year 2010	Projection 2011	Projection 2012
New Hires (Cumulative)	75.0 FTE	68.0 FTE	137.0 FTE	150.0 FTE	150.0 FTE	150.0 FTE
2007 Budgeted FTE	1,534.0 FTE	1,597.5 FTE	1,582.8 FTE	1,561.4 FTE	1,529.2 FTE	1,485.6 FTE
Total	1,609.0 FTE	1,665.5 FTE	1,719.8 FTE	1,711.4 FTE	1,679.2 FTE	1,635.6 FTE

Conclusion

Over the next ten years, the impact of the aging workforce and the projected loss of skills and experience due to retirement present serious challenges to THESL's plan to modernize its asset while fulfilling its responsibility to its customers. Forecasted shortages of labour and skills add to the challenge. Fully competent workers who are well trained and skilled in performing the critical components of their role are needed to fill the jobs that are essential to THESL's meeting its responsibility. To ensure that these individuals are in place and ready to perform, THESL has embarked on a proactive approach to hire, train and develop the workers who are required to ensure the safe, reliable operation of its distribution system in service to its customers.

BUILDINGS AND FACILITIES

FACILITIES POLICY

The Facilities Policy describes the principles for making prudent investment decisions in facilities assets, including Administrative (Non Distribution System) and Substation (Distribution System) assets. The policy's objective is to establish the principles for making prudent investment decisions in Facilities Assets to support the business strategies, plans and requirements of THESL.

Investment decisions are typically made at several points during the lifecycle of each Facilities Asset, and are guided by the following principles:

- ***Acquisition***. THESL generally purchases required facilities. However, lease arrangements are sometimes made to meet temporary business requirements and address functional obsolescence of facilities (typically five years or less).
- ***Design and Construction.*** Use THESL's competitive procurement process and internal construction resources to minimize costs and meet THESL business unit requirements.
- ***Maintenance and Refurbishment***. Identify ongoing building maintenance and refurbishment requirements through regular inspection. Re-define and refurbish surplus facilities to meet new requirements.
- ***Decommissioning and Disposal***. Where a surplus facility asset cannot be used for another THESL purpose, decommission and dispose of the asset on the open market to maximize net proceeds.

The guiding principle for all investment decisions regarding each Facilities Asset, over its total lifecycle, is to maximize the net benefits it delivers having due regard for its use. In accordance with this principle, the cost of acquiring real property and constructing and maintaining buildings must enable THESL to maximize the stream of net benefits

flowing from the investment. Investment decisions regarding Facilities Assets consider whether an asset is Functional, Optimizing or Enabling.

- ***Functional***. Facilities Assets acquired and/or constructed as part of the distribution system (for example, a Municipal Substation) are typically only functional in nature and are location-specific; the benefit is solely for the delivery of power to customers. In this case, investment decisions are justified by minimizing lifecycle costs, through competitive procurement driven by specific functional requirements, and through regular inspection and refurbishment of facilities to minimize total operational costs.
- ***Optimizing***. Facilities Assets acquired and/or constructed for general distribution purposes (for example, a Service Centre) provides not only functional benefits, but also the opportunity to optimize the work of the organization, thereby reducing overall operating costs. A well-chosen site for a Service Centre can significantly reduce travel time, decreasing response time to emergencies and contribute to increasing the productivity of field workers. A well-designed building can support the optimal flow of materials (such as in a warehouse) and work (such as in a repair and maintenance shop). Competitive procurement, in this case, would consider not only functional requirements, but also the optimizing benefits. For example, one site may be ideally located, and another site may require an additional ten minutes of travel time, per field worker, per day. The optimizing benefits may more than compensate for a higher initial cost of the ideally located site.
- ***Enabling***. Facilities Assets acquired and/or constructed for administrative purposes (for example, a Head Office), can provide not only functional and optimizing benefits, but can also provide the environment for THESL staff to collaborate effectively on departmental and cross-functional projects. By investing in facility characteristics that inspire individuals and teams to operate efficiently and effectively, additional enabling benefits can be achieved, including

increased employee commitment, continuous improvement, decreased errors and costs, and improved quality and productivity. Competitive procurement in this case would be the most complex, considering not only functional and optimizing requirements, but also enabling requirements.

To minimize lifecycle maintenance costs of Facilities Assets, annual condition surveys are conducted by maintenance and operations staff, and comprehensive condition assessments are conducted on a five-year cycle. These surveys identify problems, deficient conditions, and maintenance needs at sites, buildings, and other structures. Investment decisions are made annually regarding the maintenance and refurbishment of drainage, site circulation, utilities, building structural frame and foundation, roofs, plumbing systems, heating and air-conditioning systems, electrical systems, fire emergency systems, and interior finishes. Adherence to legislative standards and conformance with safety and environmental standards are considered THESL's highest priority maintenance and refurbishment investments.

BUILDINGS AND FACILITIES

FACILITIES PLAN AND OVERALL COSTS

The Facilities Plan for THESL describes the plans for major investments in facilities assets during the bridge year and test years.

Introduction

THESL currently operates from seven facilities scattered across the City of Toronto. Most of the buildings are obsolete, sub-optimally located, and are not configured to efficiently support THESL's current or future operations. Most of the buildings are characterized by poor functionality, relatively high operating costs and relatively low utilization rates.

During the five-year period of the Facilities Plan, from 2007 to 2011, THESL operations will be consolidated from seven to three facilities. These facilities will be optimally located to provide responsive service to customers throughout the City of Toronto. The facilities will also be designed and configured to fully support the development of a new workplace culture, leading to significant increases in both operational efficiency and overall effectiveness.

Upon the completion of the Facilities Plan, all of THESL's employees will be housed in the following three facilities:

- ***Corporate Office***. A renovated corporate headquarters and administrative centre at the existing 14 Carlton Street building.
- ***North Multipurpose Service Centre***. A new multipurpose service centre to be constructed on a site to be acquired in the northern part of THESL's service area (easy access to Highway 401 corridor for East-West travel).

- ***South Multipurpose Service Centre***. A refurbished multipurpose service centre at the existing 500 Commissioners Street facility in the southern part of THESL's service area (easy access to Gardiner Expressway and Lakeshore Boulevard for East-West travel).

Following the successful completion of the Facilities Plan, net benefits will be maximized in three ways:

- ***Functional***. New and refurbished facilities will increase space utilization and help control operating costs.
- ***Optimizing***. By choosing optimal sites for the facilities, travel time will be minimized, decreasing response time to emergencies as well as increasing the productivity of field workers. With optimal layout of interior and exterior space, operating costs can be minimized and productivity improved.
- ***Enabling***. New and refurbished facilities enable THESL to invest in design features that encourage and fully support the development of a new workplace culture and improve the Quality of Working Life ("QWL"). This new workplace culture and improved QWL will improve overall THESL performance by enabling a climate for innovation and creativity, improving team and group communication and interaction, business processes, corporate culture, and employee pride and loyalty.

Strategy

The strategy for achieving the goal of consolidation from seven to three facilities over a five-year period is to divide the work into three projects as follows:

- ***Downsview***. The Downsview project will first acquire a suitable site near the Highway 401 corridor to establish the North Multipurpose Service Centre, and then build a suitable facility on the site.

- ***Transition***. The Transition Project is focused on providing temporary leased facilities until the Downsview facility is built and ready for occupancy. The 10 Belfield facility will be replaced by a temporary leased facility at 6 Monogram, and the 28 Underwriters facility will be replaced by a temporary leased facility at 601 Milner.
- ***Improvement***. The Improvement Project is focused on refurbishing, renewing and optimizing two THESL buildings to be retained as Facilities Assets. The 14 Carlton building requires a major refurbishment to bring building mechanical, electrical and safety systems to code and meet Class "B" office building standards. The 500 Commissioners building requires refurbishment to re-define it as the South Multipurpose Service Centre.

The strategy has already resulted in the complete separation of the functional affiliates and THESL by moving all THESL employees out of the 10 Belfield facility, and moving in employees of Toronto Hydro Telecom Inc. ("THTI") and Toronto Hydro Energy Services Inc. ("TH Energy"), which includes Street Lighting, into the 10 Belfield facility.

The employees of Toronto Hydro Corporation ("THC") will continue to reside at 14 Carlton as the bulk of their activities are performed on behalf of THESL. THESL charges THC occupancy charges to reflect the space used by its employees. The occupancy charges are based on our cost allocation model described in Exhibit C1, Tab 4, Schedule 3.

Downsview Project

The Downsview project will first acquire a suitable site to establish the North Multipurpose Service Centre, and then build a suitable facility on the site.[1]

[1] To avoid prejudicing the acquisition process, this filing does not discuss the specific location, size and other attributes of the new facility.

The facility will house the THESL control centre, call centre, vehicle service yards, vehicle parking, equipment repair facilities, job staging area, materials handling facilities, crew facilities including locker and change rooms, office space, warehouse space and other associated facilities.

The project began in July 2004. Site selection is anticipated to be completed by December 2007, concluding with the approval of an Agreement of Purchase and Sale ("APS") for the new site. Once the site has been acquired and any land use and environmental issues resolved, THESL will begin the detailed design, construction and occupancy of the facility to be built on the site. This phase of the project is expected to be completed by December 2011.

Capital costs for the site acquisition phase of the project are included in the 2007 capital budget. The initial site acquisition cost, including land, external consultants, and internal staff, is budgeted at $1M in 2007. The total multi-year capital costs through 2011 for the acquisition, design, construction and occupancy of the new site and facility are estimated at $48M as shown in Table 1 below:

Table 1: Capital Cost ($000s)

LOCATION	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	2011	TOTAL
Downsview		1,000	15,000	12,400	9,800	9,800	**48,000**

Transition Project

The Transition Project is focused on providing temporary leased facilities until the Downsview facility is built and ready for occupancy.

Approximately 300 THESL staff have moved from the 10 Belfield facility to a temporary leased facility at 6 Monogram, and 220 THESL staff will be moved from the 28 Underwriters facility to a temporary leased facility at 601 Milner.[2]

The 6 Monogram facility was occupied in three phases. Phase I, the relocation of office staff, was completed in December 2006. Phase II, including utility fleet, construction operations and material distribution, was completed in February 2007. Phase III renovation, to provide crew facilities, including locker rooms, showers, and work spaces for construction supervisors, was completed in May 2007.

In the case of the relocations to both 601 Milner and 6 Monogram, employees were relocated from outdated and cramped facilities that were not well configured to meet today's business requirements, to two newly renovated facilities configured to fully meet THESL requirements. Furthermore, relocating employees to 601 Milner, which is closer to the major distribution system refurbishment currently underway in north-eastern Toronto, will result in travel time savings.

The annual lease cost for the Monogram facility is $2M in 2007 through 2009, and $2.1M in 2010. The annual lease cost for the Milner facility is $1M in 2007 (half-year), $2M in 2008 and 2009, and $2.1M in 2010. Additional maintenance costs annually are $600,000 per year for each facility. For 2007 additional maintenance costs for Milner will be $300,000. The cost for furniture is $700,000 at Monogram and $1.5M at Milner.

The 10 Belfield facility has since been sold to TH Energy to accommodate the employees of THTI and TH Energy. Based on an appraisal provided by J.J. Barnicke Limited, the facility was sold to TH Energy at fair market value for $5.8M.

[2] While the bulk of the employees from Underwriters Place will relocate to Milner Avenue, a few will relocate to Commissioners Street.

The budget by year for the Transition Project is as follows:

Table 2: Transition Project Budget ($000s)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Capital Improvement Monogram	1,500			
Capital Improvement Milner	6,000			
Operating	3,900	5,200	5,200	5,400

Improvement Project

The Improvement Project is focused on refurbishing, renewing and optimizing two THESL buildings to be retained as Facilities Assets. This project began in October 2006, and is anticipated to be completed within five years, by December 2011.

<u>14 Carlton</u>

The 14 Carlton building is a nine-story designated heritage building constructed in 1932, and has not had a major renovation since 1972. The building has an outdated and somewhat disjointed image, reflecting a variety of separate initiatives to address amalgamation, conservation, usage and modernization. As the current head office of THC and THESL, a comprehensive condition assessment has revealed the need for extensive renovation and refurbishment to bring all building systems into compliance with current building code and Class “B” office building standards.

Major infrastructure improvements must be made to fire safety systems, emergency generators, electrical switchgear, elevators, roofing, exterior stone cladding, parking facilities, piping and air-handling systems to maintain the building in a safe and usable

condition. In addition to the infrastructure work, office modernization and space optimization work, including carpet and office furniture replacement, is required on all nine floors to improve the overall working environments. All projects will be undertaken while employees remain in the building; temporary staging moves will be used on a floor-by-floor basis to accommodate construction.

Table 3: Infrastructure Improvements by Year for 14 Carlton

2007 Major Projects: 1. Computer Room Haylon Conversion 2. Emergency Generator Replacement 3. Switchgear Replacement 4. Electric Boiler Replacement 5. New Fire alarm and Smoke Repression System 6. 5th Floor Replace Carpet 7. Mezzanine Carpet 8. Replace Washroom Heaters 9. Replace Sump Pump Control Panel 10. Install Motorized Damper to SF-11 11. Cafeteria Exhaust Hood Controls 12. Rooftop Exhaust Fans 13. 1st Floor east side carpet 14. Office Furniture 15. North Elevation Shelf Angle Replacement	2008 Major Projects: 16. Replace Roofs 4, 6, & 9 17. Retrofit Freight Elevator 18. Passenger Elevators Retrofit 19. Office Furniture 20. Duct Cleaning 21. Shaft Riser Piping Replacement
2009 Major Projects: 22. Lobby Ceiling Replacement 23. Office Furniture	2010 Major Projects: 24. New Parking Structure 25. Office Furniture
2011 Major Projects: 26. Office Furniture 27. Replace Roofs 3, 5 & 8	

The capital budget by year for improvements to the 14 Carlton:

Table 4: 14 Carlton Improvements ($000s)

LOCATION	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	2011	TOTAL
Carlton		1,500	4,000	1,000	2,000	1,600	**10,100**

500 Commissioners

The 500 Commissioners building will be repurposed as the South Multipurpose Service Centre, and paired with a new North Multipurpose Service Centre to be constructed in the northern part of the city.

The existing 500 Commissioners Street structure will be refurbished as required, exterior and interior space will be optimized to meet the requirements of the infrastructure plan, and a gas turbine co-generation facility will replace the existing emergency standby generator that is insufficient for the planned needs.

The capital budget by year for the 500 Commissioners improvements is as follows:

Table 5: 500 Commissioners Improvements ($000s)

LOCATION	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	2011	TOTAL
Commissioners					4,800	2,600	**7,400**

Surplus Disposal

The Disposal project is focused on decommissioning and selling surplus THESL Real Estate assets to free up invested capital for reinvestment. Assets to be sold (by target year) include:

- 10 Belfield (2006)

- 175 Goddard (2007)
- 28 Underwriters (2008)
- 60 Eglinton (2010)
- 5800 Yonge (2010)

The first disposal in 2006 was 10 Belfield. This Real Estate/Facility asset was sold to Toronto Hydro affiliates, TH Energy and THTI, to serve as their corporate office.

Every year, THESL disposes of a number of obsolete facilities and real estate assets. However, beginning in 2007, the disposal process will be accelerated. Acceleration of the normal disposal process will free up capital required to support the THESL 10-year infrastructure plan, by acquiring more suitable real estate and constructing or refurbishing more optimal facilities.

Table 6: Proceeds from Disposal of Surplus Property ($000s)

GROSS REVENUE	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Surplus Sale Revenue Plan	6,468	13,148	8,000	0	5,000

Table 7: MPAC-Fair Market Value ("FMV") Basis ($000s)

Disposal Plan	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	2011	TOTAL
5800 Yonge						30,000	**30,000**
60 Eglinton	0	0	0	0	5,000		**5,000**
28 Underwriters	0	0	8,000	0	0		**8,000**
175 Goddard	0	8,000	0	0	0		**8,000**
10 Belfield	5,800	0	0	0	0		**5,000**
105 Orfus	0	478	0	0	0		**400**
298 Sorauren	338	0	0	0	0		**270**
101 Jefferson	330	0	0	0	0		**350**
Mowat	0	670	0	0	0		**700**
Wilson	0	2,600	0	0	0		**2,600**
124 Birmingham	0	400	0	0	0		**400**
3706 Bathurst Street	0	250	0	0	0		**250**
522 Rustic	0	450	0	0	0		**450**
211 Sterling Road	0	300	0	0	0		**300**
Total	**6,468**	**13,148**	**8,000**	**0**	**5,000**	**30,000**	**61,720**

Overall Cost Summary

Table 8: Facilities Plan Capital Cost ($000s)

LOCATION	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	2011	TOTAL
Downsview		1,000	15,000	12,400	9,800	9,800	**48,000**
Carlton		1,500	4,000	1,000	2,000	1,600	**10,100**
Commissioners					4,800	2,600	**7,400**
Facility Baseline	5,600	3,800	6,300	4,400	5,500	6,807	**32,407**
Monogram		1,500					**1,500**
Milner		6,000					**6,000**
Belfield	**SOLD**	0					**0**
Goddard		**SELL**					**0**
Underwriters		0	**SELL**				**0**
Eglinton		0			**SELL**		**0**
Yonge		0				**SELL**	**0**
	5,600	**13,800**	**25,300**	**17,800**	**22,100**	**20,807**	**105,407**

Table 9: Expected Revenue from Disposal of Surplus Property ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	2011	TOTAL
Net Book Value	4,402	192	6,453	0	600		
Disposal Cost	See footnote 3	1,200	800	0	500		
Total Revenue	6,468[3]	13,148	8,000	0	5,000	30,000	61,720
Related Party Gain	(1,476)[4]						
Gain on sale	590	11,757	786	0	3,940		

[3] 2006 Revenue is net of disposal cost.
[4] Belfield Road facility was sold to TH Energy which gives rise to a Related Party Gain attributable to TH Energy.

The treatment of capital gains and losses is discussed in Exhibit D1, Tab 12, Schedule 1. The company's proposal to allocate 50 percent of the gain on sale to customers as a revenue offset is shown in Exhibit I1, Tab 1, Schedule 1.

Table 10: Facilities Plan Operating Cost ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Total Operating Costs	24.30	36.70	38.60	39.60	41.00

The facilities costs included above are allocated to all the business units of THESL and to affiliates based on usage of space and following our cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, the facilities cost are neutral after allocation as each business unit carries their portion of facilities costs (the costs shown above are before allocation).

For a detailed discussion of the Facilities Services operating requirements and costs, see Exhibit F1, Tab 3, Schedule 1.

MATERIAL AND PROCUREMENT

SUPPLY CHAIN PROCUREMENT POLICY

The Toronto Hydro Procurement Policy was established to:

- comply with the legislative requirements regarding competitive bids;
- comply with new rules and regulations regarding internal controls as legislated under Bill 198;
- establish uniform procurement process across all Toronto Hydro affiliates; and
- comply with Electrical Safety Association requirements under Ontario Regulation 22/04.

The basic principles of the Procurement Policy are:

- to obtain quality goods / services at best overall value;
- to promote competition among suppliers and contractors;
- to provide for fair and equitable treatment of all suppliers and contractors;
- to safeguard to protect corporate integrity;
- to meet or exceed safety and environmental requirements; and
- to comply with all applicable laws.

The latest version of the Procurement Policy dated July 1, 2007 and the latest version of the Inventory Management Policy dated February 26, 2007 are attached to this Schedule as Appendix A and Appendix B respectively.

Toronto Hydro Procurement Policy (Revised May 31, 2007)
Effective Date: July 1, 2007
Responsibility Center: Procurement Department, THESL
Review Date: June, 2009

PROCUREMENT POLICY

Application

This Procurement Policy applies to Toronto Hydro Corporation and to all of its Affiliates.

Except as otherwise authorized by the Board, the President or the CEO, all Procurements made by Toronto Hydro Corporation and its Affiliates must be authorized and executed in accordance with this Procurement Policy.

Previous Policies

This Procurement Policy supersedes and replaces all previous procurement policies, procedures and forms, including without limitation Toronto Hydro's Procurement Policy dated July 12, 2005.

Supporting Documents

This Procurement Policy shall be read and applied in conjunction with the Signing Policies, as well as the following procedures and forms:

TAB	SUPPORTING DOCUMENT
(a)	Procurement Department Administration Form;
(b)	Procedure for Competitive Bids;
(c)	Competitive Procurement Request Form;
(d)	Opening Bids Summary Page;
(e)	Competitive Bid Evaluation Report/Recommendation;
(f)	Sole Source Justification Report;
(g)	Extending Existing Contract Justification Report;
(h)	Procedure to Document Approved Procurements; and
(i)	Construction Contractor Pre-Qualification Application.

Policy Statement

Toronto Hydro Corporation is committed to establishing and maintaining a procurement system that:

(a) ensures that quality goods , services and construction contracts are procured efficiently and at the most favorable prices available to Toronto Hydro Corporation and its Affiliates;

(b) promotes the use of competition in selecting suppliers and contractors;

(c) provides for the fair and equitable treatment of all suppliers and contractors;

(d) provides safeguards for maintaining a procurement system of quality and integrity;

(e) ensures that all suppliers of goods or services meet or exceed Toronto Hydro Corporation's safety and environmental requirements; and

(f) ensures that all Procurements are made in compliance with all applicable laws

General Rules

Unless otherwise authorized by the Board, the President or the CEO:

(a) Procurement Department: all Procurements shall be administered by the Procurement Department and authorized by the Procurement Manager or his/her authorized delegate.

(b) Competitive Bids: save and except for the Exceptions noted below, all Procurements shall be sourced via the Procedure for Competitive Bids (tab B).

(c) Documentation of Approved Procurements: all approved Procurements (regardless of value or whether they were approved via a competitive bid process or not) shall be processed and documented in accordance with the Procedure to Document Approved Procurements (tab H).

(d) Information Technology: All Procurements of information technology related goods or services (including computer equipment or software or related services) must be made in accordance with Toronto Hydro's "Systems and Client Support

Services Hardware and Software Purchase Policy and Procedures" and any such Procurements with a Contract Value greater than $25,000 must also be approved by the CIO.

(e) Maximum Terms: the maximum initial term for any Procurement contract shall be of 5 years, with a maximum renewal term(s) of up to 5 years.

(f) Procurement Manager's Discretion: the Procurement Manager shall have the right at any time to request that a particular Procurement be made through the Procedure for Competitive Bids (tab B).

Exception No. 1 – Petty Cash or Procurement Credit Card Purchases

This Procurement Policy does not apply to Procurements that are processed via Toronto Hydro Corporation's Petty Cash or Procurement Card Card procedures or policies, as implemented or amended from time to time.

Exception No. 2 – Purchases Below $25,000

Procurements with a Contract Value below $25,000 need not be sourced via the formal Procedure for Competitive Bids (tab B).

Instead, the Procurement Manager may, in his/her discretion, approve Procurements not exceeding $25,000 in Contract Value without receiving any written quotations if:

(i) the Procurement is made from a qualified vendor which has previously proven through competitive bidding to offer consistently competitive pricing, reliable services and delivery; and

(ii) the market is surveyed by the Procurement Department annually to confirm that the vendor is providing competitive pricing and service.

Exception No. 3 – Purchases Below $250,000

Procurements with a Contract Value below $250,000 need not be sourced via the formal Procedure for Competitive Bids (tab C).

Instead, the Procurement Department shall solicit no less than three (3) written price quotations and submit the results thereof to the Business Unit for review and selection.

Exception No. 4 – Sole Source Procurements

The following procedure shall be followed where a Business Unit wishes to purchase any goods or services (including construction contracts) from a sole source vendor, without going through the Procedure for Competitive Bids (tab B):

(a) In order to obtain approval for a sole source purchase, the Business Unit must complete, sign, and submit a Sole Source Justification Report (tab F) to the Procurement Department. The Sole Source Justification Report (tab F) will require appropriate signing authority in accordance with Toronto Hydro's Signing Policies.

(b) Upon receiving a completed Sole Source Justification Report (tab F), the Procurement Department will conduct a due diligent review of the sole source purchase request to confirm that no other vendor can provide the good/service required, and to determine if such sole source purchase is in the best interests of Toronto Hydro Corporation and its Affiliates, including a review of the proposed contract's specifications, scope, definition, commercial terms, liabilities, and insurance requirements.

(c) If approved by the Procurement Department, the Sole Source Procurement shall be processed by the Procurement Department in accordance with the Procedure to Document Approved Procurements (tab H).

Exception No. 5 - Extension of Existing Contracts

The following procedure shall be followed where a Business Unit wishes to exercise its contractual right to extend an existing procurement or construction contract without going through the Procedure for Competitive Bids (tab B):

(a) In order to obtain approval to extend an existing contract, the Business Unit must complete, sign and submit an Extension Justification Report (tab G) to the Procurement Department. The Extending Existing Contract Justification Report (tab G) will require appropriate signing authority in accordance with Toronto Hydro's Signing Policies.

(b) Along with the Extending Existing Contract Justification Report (tab G), the Business Unit must also provide the Procurement Department with a copy of the current contract containing the right of extension.

(c) Upon receiving a completed Extending Existing Contract

Justification Report (tab G) and copy of the current contract, the Procurement Department will conduct a due diligent review of the extension request to determine if the current contract permits such an extension and whether such extension is in the best interests of Toronto Hydro Corporation or its Affiliates, including a review of the proposed contract's specifications, scope, commercial terms, liabilities, and insurance requirements.

(d) If approved by the Procurement Department, the Extension to the Existing Contract shall be processed by the Procurement Department in accordance with the Procedure to Document Approved Procurements (tab H).

Exception No. 6 – Procurements for the benefit of THESI or THTI Customers

Procurements of goods and/or services by THESI or THTI for the benefit and use of THESI/ THTI (as applicable) customers are not required to be sourced via the Procedure for Competitive Bids (tab B), or administered by the Procurement Department (but are still subject to the Procedure to Document Approved Procurements (tab H)). This exception is to allow for Procurements whereby THESI/ THTI is contracted by its customer(s) to procure goods and/or services in order to fulfill project contract obligations.

For such Procurements, THESI/ THTI shall negotiate and select the vendors from a pre-qualified list established by THESI/ THTI based on vendors who have previously proven through competitive bidding to offer consistently competitive pricing, reliable services and delivery.

This exception does not apply where THESI/ THTI requires goods and/or services for its own business use.

Other Exceptions

Such other exceptions as listed in the Procurement Department Policy Exception List authorized by the Board, the President or the CEO and posted on the Procurement Department Hub site, and as may be amended from time to time (e.g.: government services and government agencies).

Compliance

All executives of Toronto Hydro Corporation and its Affiliates shall have the responsibility to ensure compliance with this Procurement Policy in their respective Business Units and shall not authorize any Procurement outside the terms of this Procurement Policy.

Amendments to Procurement Policy

This Procurement Policy and all procedures noted herein may only be amended with the approval of the President, the CEO or the Board.

Definitions

In this Procurement Policy:

"Affiliates" means Toronto Hydro-Electric System Limited, Toronto Hydro Energy Services Inc., Toronto Hydro Telecom Inc. and any other affiliate of Toronto Hydro Corporation, from time to time.

"Board" means the Board of Directors of Toronto Hydro Corporation or of any Affiliate, as may be applicable.

"Business Unit" means the Toronto Hydro Corporation or Affiliate's department requesting the Procurement.

"CEO" means the President and Chief Executive Officer of Toronto Hydro Corporation.

"CIO" means the Chief Information Officer of THESL.

"Contract Value" means the total amount of expenditures required under any Procurement, which shall be determined by calculating the total amount of all possible expenditure over the term of the contract, including all years of a multi-year term and all years of all possible contract renewals, and shall include the potential maximum of all conditional, contingent or variable payments, excluding all applicable taxes. **Purchase requirements shall not be artificially divided so as to constitute a Contract Value under $250,000.**

"Manager" means the Senior Manager or Manager of any Business Unit with responsibility for an approved budget for the Procurement in question.

"President" means the President of THESL.

"Procurement" means a purchase, agreement to purchase, licence, lease or rental of any good or service, including an agreement to purchase construction services. The term "Procurement" shall also be deemed to include, for the purpose of any renewals or extensions to previous Procurements, the extension or renewal of any procurement or construction contract made prior to the date of this Procurement Policy.

"Procurement Department" means THESL's Acquisition Services Department.

"Procurement Manager" means the Manager or Senior Manager responsible for the operation of the Procurement Department.

"Procurement Policy" means this Procurement Policy together with all forms and procedures and forms referenced therein.

"THESI" means Toronto Hydro Energy Services Inc.

"THESL" means Toronto Hydro-Electric System Limited.

"THTI" means Toronto Hydro Telecom Inc.

"Signing Policies" means the most recent version of the signing policies of Toronto Hydro Corporation and its Affiliates, as approved by the Board.

Approved by: _____

Anthony Haines
President, Toronto Hydro-Electric System Limited

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PROCEDURE FOR COMPETITIVE BIDS

1. Application: This Procedure for Competitive Bids shall apply whenever the Procurement Policy, the President or CEO, the Board, or the Procurement Manager requires that a purchase of goods and/or services be made via a competitive process.

2. Procurement Request Form: In order to begin the competitive process, the Business Unit must complete, sign, and submit a Competitive Procurement Request Form (tab C) to the Procurement Department. The Competitive Procurement Request Form (tab C) shall contain appropriate signing authority in accordance with the Signing Policies.

3. Contract Administration Form: Upon receiving a duly completed and authorized Procurement Request Form, the Procurement Department will open a new file to administer the competitive process, and monitor the progress of such file via the Procurement Department Administration Form (tab A).

4. Solicitation Document: The Procurement Department will then conduct a due diligent review of the Procurement request to determine which of the following standard-form solicitation documents are appropriate for the Procurement in question:

   (a) a Request for Proposal shall be utilized whenever the Business Unit knows what goods and/or services it requires, but is seeking proposals from respondents regarding the method, ability and price of the procurement;

   (b) a Request for Quotations shall be utilized whenever the Business Unit knows what goods and/or services it requires, and how such goods and/or services should be provided (e.g. specifications, terms of contract) and is seeking bids from respondents in order to determine the best available price for such goods and/or services;

   (c) an Invitation to Tender and Construction Contract shall be utilized whenever the Business Unit seeks bids for any construction project; or

   (d) Such other form of solicitation document as approved by the Procurement Manager and Toronto Hydro Corporation's Legal Division.

Once the proper form of solicitation document has been determined, the Procurement Department will assist the Business Unit in completing the solicitation document and

determine the list of prospective suppliers or contractors. All solicitation documents shall be reviewed and approved by Toronto Hydro Corporation's Legal Division, prior to being sent to prospective respondents.

5. Construction Contractor Pre-Qualification: Invitations to Tender for construction projects shall only be granted to contractors having met THESL's Construction Contractor Pre-Qualification requirements (tab I).

6. Evaluation Criteria: The Procurement Department shall ensure that it has received a written set of evaluation criteria and marking scheme from the Business Unit prior to sending out the solicitation document to prospective respondents/bidders. This evaluation criteria and marking scheme shall be applied to all proposals/bids equally, and without revision.

7. Communications: The Procurement Department shall be responsible to issue and administer all competitive processes. No other representative of Toronto Hydro Corporation or its Affiliates shall communicate with any of the prospective respondents regarding the competitive process.

8. Amendments or Supplements to Solicitation Document: Any amendments or supplements to the solicitation document shall be made prior to the deadline for the submission of proposals/bids, and shall be issued in writing by the Procurement Department to all prospective respondents.

9. Receipt of Bids: The Procurement Department shall receive and keep an original copy of all proposals/bids received. All proposals/bids shall be time-stamped but not opened upon receipt, and shall be stored in a secure place until opening.

10. Modifications or Withdrawals to Proposals/Bids before Submission Deadline: Respondents shall be permitted to modify or withdraw their proposals/bids at any time prior to the submission deadline, in accordance with the instructions found in the solicitation document. After the submission deadline, all decisions to allow for the correction or withdrawal of proposals/bids shall be authorized in writing by the Procurement Manager.

11. Opening: The Procurement Department shall arrange for the opening and recording of proposals/bids, including the completion of an Opening Bids Summary Page (tab D) to determine which proposals/bids are compliant with the requirements as stated in the solicitation document. At least two (2) representatives of the Procurement Department and at least one (1) representative from the Business Unit shall be present and witness the opening of proposals/bids and shall sign the Opening Bids Summary Page (tab D). All parties present shall also sign each proposal/bids price summary sheet.

12. Review by Procurement Department: The Procurement Department shall then conduct a preliminary review of the proposals/bids and complete the Competitive Bid Evaluation/Recommendation Report (tab E). The Procurement Department will then submit a copy of the Competitive Bid Evaluation/Recommendation Report (tab E) along with a copy of all proposals/bids received, to the requesting Business Unit.

13. Proposal/Bid Review by Business Unit: The Business Unit will then perform its evaluation of the proposals/bids and complete its sections of the Competitive Bid Evaluation/Recommendation Report (tab E), including award recommendation. The Competitive Bid Evaluation/Recommendation Report (tab E) shall be signed by authorized representatives of the Business Unit, in accordance with the Signing Policies. The Business Unit shall then return its completed and signed Competitive Bid Evaluation/Recommendation Report (tab E) to the Procurement Department, for approval and signature.

14. Negotiations: Negotiations may only be conducted in accordance with the instructions and specifications as specified in the solicitation document. The communication of such negotiations shall be made solely by the Procurement Department and respondents shall be accorded fair and equal treatment with respect to any opportunity for negotiation and revision of bids/proposals. No respondent shall be provided information about any other respondent's bid/proposal, and no respondent shall be assisted in bringing its bid/proposal up to the level of any other bid/proposal. Respondents shall not be directed to reduce their proposed prices to a specific amount in order to be considered for award. A common deadline shall be established for receipt of bid/proposal revisions based on negotiations and communicated in writing to all respondents.

15. Cancellation of Competitive Process: A competitive process may be cancelled and all proposals/bids that have already been received may be rejected by the Business Unit and the Procurement Department if:

    (a) the Business Unit no longer requires the Procurement in question;

    (b) the Business Unit can no longer reasonably expect to fund the procurement or construction project;

    (c) necessary amendments to the solicitation would be at such magnitude that a new solicitation would be desirable;

    (d) prices exceed available funds and it would not be appropriate to adjust quantities to come within available funds;

(e) there is reason to believe that proposals/bids may not have been independently arrived at in open competition, may have been collusive, or may have been submitted in bad faith;

(f) for any other good cause of a similar nature that is in the best interest of Toronto Hydro Corporation and its Affiliates.

The reasons for cancellation shall be documented in the Procurement Department Administration Form (tab A) and a written notice of cancellation (without reasons) shall be sent by the Procurement Department to all recipients of the solicitation document.

16. Award: The Procurement Department shall approve the Business Unit's award recommendation if such award to be made to a compliant respondent/bidder who, in the Business Unit and Procurement Department's evaluation, offers the greatest overall value to Toronto Hydro Corporation and its Affiliates, taking into account price, technical, and other factors as specified in the solicitation. If only one compliant proposal/bid is received, an award shall not be made unless a cost analysis verifies the reasonableness of the price. All awards shall be made to responsible contractors, i.e., those who have the technical and financial competence to perform and who have a satisfactory record of integrity, compliance with applicable laws, record of past performance, and financial and technical resources. All parties having submitted a proposal/bid in response to a competitive process shall be advised, in writing, of whether their proposal/bid has been selected or not.

17. Award Protests: If an actual or prospective supplier or contractor protests the solicitation or the award of a contract, such protest shall be requested to be submitted in writing to the Procurement Manager, who may, in his or her discretion, suspend the Procurement pending resolution of the protest, if warranted by the facts presented.

18. Conflicts of Interest: No employee of Toronto Hydro Corporation or its Affiliates shall participate directly or indirectly in the selection, or in the award or administration of any contract if a conflict of interest, real or apparent, would be involved. Such conflict of interest will be deemed to arise where financial or other interests in the supplier or contractor is held by the employee involved in making the awards, by his or her partner or other relatives, or by an organization under the control of the employee in question. Without limiting the generality of the foregoing, employees shall not solicit or accept opportunities, favors, or anything of monetary value from suppliers, contractors, or parties to subcontracts, and shall not use any of the bidder/respondent proposals for actual or anticipated personal gain.

19. Documenting Award: Once a successful supplier or contractor has been selected, the Procurement Department, with the assistance of the Business Unit, shall proceed to

document the purchase in accordance with the Procedure to Document Approved Procurements (tab H).

20. Previous Procedures: This Procedure and all forms mentioned herein shall be deemed to replace and supersede any and all other competitive bid procedures or forms and, unless otherwise authorized by the Board, no other procurement method or forms shall be utilized to administer a competitive process.

21. Defined Terms: Any capitalized terms used but not defined herein shall have the meaning as defined in Toronto Hydro Corporation's Procurement Policy.

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PROCEDURE TO DOCUMENT APPROVED PROCUREMENTS

1. Application. This Procedure to Document Approved Procurements shall apply to all purchases of goods, services or construction contracts, whether such Procurement has been selected via a competitive bid process, or not.

2. Procurement Department's Responsibility. The Procurement Department shall be responsible, with the assistance of the requesting Business Unit, to ensure that all approved Procurements are documented in accordance with this Procedure.

3. Procurements of Goods and/or Services under the Threshold Value. For Procurements of goods only the "Threshold Value" is a Contract Value of $500,000. For Procurements of services or a combination of goods and services, the "Threshold Value" is a Contract Value of $250,000. Unless otherwise permitted under the Procurement Policy or by the President, the CEO or the Board, where the Contract Value for the approved Procurement of goods and/or services is below the applicable Threshold Value:

   (a) If the Business Unit or the supplier proposes a form of contract, the Procurement Department shall submit the proposed form of contract to Toronto Hydro's Legal Division, for review and approval. Once the Legal Division has approved the contract, it must be executed by an authorized representative of the Business Unit (in accordance with the Signing Policies) and the supplier of goods/services prior to issuing payment for the goods and/or services in question. A copy of the executed contract shall be held in both the Procurement Department and the Legal Division's files.

   (b) If no form of contract has been proposed by the Business Unit or the supplier, then the Business Unit will complete and submit a purchase requisition to the Procurement Department for the agreed upon price of the goods and/or services. The purchase requisition shall be signed by an authorized representative of the Business Unit (in accordance with the Signing Policies). Upon receipt of a properly authorized purchase requisition, the Procurement Department will issue a purchase order to the supplier, along with the Standard Form Terms and Conditions for the Purchase of Goods or Services. A copy of the Purchase Requisition shall be held in the Procurement Department's files.

4. Procurements of Goods and/or Services Equal or Over the Threshold Value. Unless otherwise permitted under the Procurement Policy or the Board, all Procurements of goods and/or service with a Contract Value equal to or over the Threshold Value shall be evidenced by a contract that has been approved by Toronto Hydro's Legal Division. Once the contract has been approved by the Legal Division, it must be executed by an authorized representative of the Business Unit (in accordance with the Signing Policies) and the

supplier of goods/services prior to issuing payment for the goods or services in question. A copy of the executed contract shall be held in the Procurement Department and an original of the executed contract shall be held in the Legal Division's files.

5. Construction Contracts: Where the Procurement in question is a construction contract, the standard form construction contract, or such other form of construction contract as approved by the Legal Division and the Procurement Manager, shall be used, regardless of Contract Value. Such construction contract shall be reviewed and approved by Toronto Hydro's Legal Division and will require appropriate signing authority in accordance with the Signing Policies. A copy of the executed contract shall be held in both the Procurement Department and an original of the executed contract shall be held in the Legal Division's files.

Toronto Hydro- Electric System Limited
POLICY DOCUMENT

V20051113.1600

INVENTORY MANAGEMENT POLICY	**Process Owner - Department:** Supply Chain
	Process Owner – Group/Responsibility Centre: Demand Management
	Effective Date: February 26, 2007
The most recent version of this policy can be obtained from the Supply Chain Department	

APPROVED BY	SIGNATURE	DATE
Ivano Labricciosa Vice-President, Asset Management		*February 26,2007*
Anthony Policicchio Manager, Procurement Department	for A.P.	*February 26,2007*
Stephen Lui Supervisor, Demand Management		*February 26,2007*

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1 POLICY DOCUMENT INTRODUCTION

1.1 Policy Definition

A "*Policy*" reflects Toronto Hydro-Electric System Ltd (THESL) position on issues and is something that must be adhered to by its employees. It provides interpretation for and influences decisions and actions. A policy differs from guidelines and procedures.

"*Guidelines*" recommend the way in which a procedure is executed or the way in which a condition is managed. Guidelines allow flexibility for employees to make decisions – a policy does not allow this flexibility.

"*Procedures*" are more detailed methods and activities established for the implementation of established policies. A policy is 'what' the company does or should do and procedures are 'how' it carries out the expressions of its policy. Detailed procedures are not described in a policy document.

1.2 Policy Contents

Among other things, a policy describes the objectives, scope, responsibilities and requirements that apply to the organization or departments that have been identified in a policy. A THESL policy facilitates compliance with internal or external standards or requirements, to meet its operating objectives and reduce risks.

1.3 To be effective and to maximize user acceptance, a policy should be comprehensive yet easy to understand and it should be well communicated and easily accessible to the user community.

2 SCOPE

2.1 This policy applies to all departments of Toronto Hydro- Electric System Limited.

3 OBJECTIVES

General objectives of Executive and Management of the Demand Management Section in Procurement Department are to:

3.1 Understand the financial, operational and regulatory risks.

3.2 Implement the required controls to manage those risks with a control structure that provides appropriate evidence and assurance that the risks are adequately controlled.

3.3 Ensure compliance with applicable laws and regulations.

Specific objectives of this policy which relate to Demand Management activities:

3.4 It is the intent that a general level of inventory be maintained to meet the demand of the construction and maintenance work programs and potential emergency situations. The level of inventory should reflect a balance between corporate customer service, efficiency of operations, inventory investment and management cost control objectives.

4 Demand Management, Inventory Classification, Stocking Policy, Stock Take (Cycle Counts), Material Disposition, Material Reclaim

4.1 Demand Management

4.1.1 Shall ensure that inventory levels for materials are determined via accepted inventory control techniques and algorithms.

4.1.2 Shall maintain a perpetual inventory system.

4.1.3 Shall monitor and report corporate wide inventory transactions with the purpose of developing and maintaining appropriate performance measurement criteria which will be used to justify to senior management the inventory investment.

4.1.4 Shall ensure that inventories are maintained at levels which minimize the occurrence of stock-outs that cause work schedule delays.

4.2 Inventory Classification

4.2.1 Standard (MRO) Stock is defined as: All materials which are used on a repetitive bases, where reorder algorithms can be applied, and which may be purchased in volume. As a basic guideline, all materials that are issued four or more times per year are defined as standard stock.

4.2.2 Non-Standard Stock or “As required Materials” is defined as: All materials that are needed for specific jobs and are not used on a repetitive basis. Non-Standard Stock materials are ordered on an “as required” basis, however, where the lead times are extensive, non-standard stock materials can be ordered if the users departments provide a written demand forecast.

4.2.3 MRO is defined as: materials that are required to meet reactive maintenance, repair, unplanned or emergency demands. This classification is divided into three subgroups:

4.2.3.1 MRO Stock is based on the unscheduled material usage in Ellipse.

4.2.3.2 Reactive Maintenance Only (RMO) is defined as materials used for the maintenance of the Legacy Standards only and not to be used in Planned Capital programs.

4.2.3.3 Critical Spare is defined as materials held in reserve for used during System emergency/extended outage.

4.2.4 Standard (MRO) Stock stocking quantity levels shall conform to 4.3 Stocking Policy.

4.3 Stocking Policy

4.3.1 All material inventory shall have quantities based on acceptable inventory control methodologies and techniques:

4.3.1.1 Inventory levels shall not exceed three months future demand for Class “A” items, six months future demand for Class “B” items, and twelve months future demand for Class “C” items.

4.3.1.2 Where applicable, a 95% service level in calculating the appropriate ROP/ROQ stock level for each future planning period shall apply.

4.3.1.3 To accommodate special request for specific stocking levels above and beyond the calculated level, a written notification for each item identified as well as the recommended stocking level are required from the user departments.

4.3.1.4 Justification for Special request, RMO and Critical Spare Stock levels shall be reviewed at least annually. The review process will be initiated by the Demand Management Section of the Procurement Department

4.4 Stock Take (Cycle Counts)

4.4.1 Stock Take and inventory reconciliation shall be a shared responsibility.

4.4.1.1 Demand Management shall identify the items to be counted and their frequency.

4.4.1.2 Stores personnel shall conduct the actual Stock Take (Cycle Counts).

4.4.1.3 Demand Management shall report Stock Take (Cycle Counts) performance and reconcile variances.

4.4.1.4 The Manager of Procurement shall review the Stock Take (Cycle Counts) and value variances, and insure the appropriateness of the adjustments.

4.4.2 Stock Take (Cycle Counts) shall be scheduled daily.

4.4.3 Frequency of counts shall be based on the following minimum criteria:

A material items – 4 times a year

B material items – 2 times a year

C material items – 1 time a year

D material items – 1 time a year

4.4.4 Items with count variances greater than 10% and/or value variance of greater than $1,000 shall be rescheduled for recount during the same month and before the month-end cut-off date.

4.5 Material Disposition

4.5.1 Demand Management shall provide quarterly reports of DNP-Obsolete, DNP-Deplete, slow moving and non-moving inventory.

4.5.1.1 DNP-Obsolete are materials identified by Standards and Materials section that this item shall no longer be used in the system and shall be disposed .

4.5.1.2 DNP-Deplete are items identified by Standards and Materials section that this item shall no longer be purchasable but it can still be consumed in the System, criteria for disposal are as follows:

4.5.1.2.1 No open requirements, and

4.5.1.2.2 No forecast for the next 12 months

4.5.1.3 Non-moving inventory is based on the following criteria:

4.5.1.3.1 No usage during the previous two years, and

4.5.1.3.2 No MRO requirements, and

4.5.1.3.3 No open requirements, and

4.5.1.3.4 No forecast.

4.5.1.4 Slow moving inventory is based on all items which have inventory in excess of the following highest criteria:

4.5.1.4.1 Two years usage based on the previous two years.

4.5.1.4.2 ROP/ROQ quantity,

4.5.1.4.3 Open requirements

4.5.1.4.4 Forecast

4.5.2 Standards and Materials Section and other User Departments are to review the Slow/Non moving reports and make their recommendation(s) to either retain or dispose the materials.

4.5.2.1 Where the recommendation is to retain the materials, written justification must be provided together with a specific plan for usage of the retained material or a declaration of required MRO Stock.

4.5.3 Monthly, Demand Management will originate a Request to Scrap report. This report will be based on the DNP-Obsolete, DNP-Deplete, Slow/Non moving reports and recommendations for disposal received from other departments.

4.5.4 Annually, Demand Management Section will review the Obsolescence Budget in conjunction with Standards and Materials Section and User Departments.

4.6 Material Reclaim (Transformer, Protector, Switchgear, Switch, Pole etc.)

4.6.1 Reclaimed materials are used materials removed from the field because of various reasons but are still in good working conditions.

4.6.2 Based upon recommendations and guidelines specified by Standards and Materials Section, commodity classes such as transformer, protector, switchgear, switch, pole, etc. are being reclaimed back into inventory after they have been tested good for reuse.

4.6.3 Reclaimed materials are to be returned into the warehouse inventory using predetermined process and value as per guidelines from the Finance Dept.

4.6.4 All reclaimable materials are to be processed and returned to inventory in a timely manner.

4.6.5 Demand Management Section is to keep track of all items reclaimed into Inventory for audit purposes.

4.6.6 Refurbishment to reclaimable items are only acceptable if the cost is 50% or less of a new unit.

5 OWNERSHIP AND RESPONSIBILITIES

5.1 This policy is owned by the *Procurement Manager* and will be managed by the Demand Management Supervisor.

5.2 The Procurement Manager is responsible for:

- Ensuring that this policy is comprehensive, clear and current.
- Ensuring that this policy is implemented and communicated to the departments and staffs that are impacted.

5.3 The Demand management Supervisor is responsible for:

- Reviewing this policy annually, on year-end.
- Immediately communicating any exceptions or violations of this policy to the Controller for assessment of the impact to the financial statements.
- Communicating any proposed policy changes to the Procurement Manager for approval by the end of January.

5.4 All staff impacted by this policy are required to adhere to his policy.

5.5 All revisions to the policy must be prior approved by the Vice President, Asset Management.

6 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
RMO	Reactive Maintenance Only
ROP	Reorder Point
ROQ	Reorder Quantity
MRO	Maintenance Repair Operation
DNP	Do Not Purchase

SUPPLY CHAIN
INVENTORY MANAGEMENT & MATERIALS COSTS

INTRODUCTION

Supply Chain Inventory Management plays a key role in supporting THESL's asset modernization plan by ensuring that the optimum level of inventory is available at the right time, place, quantity and cost.

INVENTORY

From 2002 to 2006 Supply Chain has been instrumental in implementing business process initiatives that have driven significant improvements in inventory performance. The following are some of the inventory performance improvements realized over this period:

1) Inventory value reduced from $50M to $28M.
2) Inventory Turns increased from .73 to 3.46 turns per year.
3) Order Fill Rate increased from 75 percent to 95 percent.
4) Stock Keeping Unit ("SKU") Accuracy (Cycle Counts) increased from 70 percent to 97 percent.
5) Number of Inventory SKUs reduced from 20,000 to 8,000.
6) Inventory Burden Costs reduced from 35 percent to 10.15 percent.
7) Distribution Warehouses reduced from 6 to 3.

These inventory performance results were achieved during a period that saw continuous annual growth in both the planned capital and maintenance programs.

Supply Chain works with both internal and external stakeholders to develop opportunities to further improve inventory performance.

Currently over 75 percent of THESL's inventory is purchased through long-term (three- to five-year) supply agreements. The contracts are structured to drive continuous improvement through various cost reduction initiatives and the implementation of vendor value added services.

These services include vendor-held dedicated inventory, reduced materials lead times, improved product warranties, job site deliveries, job kitting, materials preassembly and vendor managed inventory ("VMI"). Harmonizing inventory SKUs and standardizing construction practices have also contributed significantly to the reduction in inventory value. Leveraging long term supply agreements and internal process improvements helps to minimize the cost pressures on key commodity groups.

Reduction of total costs in the manufacturing and distribution chain (i.e., process improvements, product design, packaging, extended warranties, distribution (storage, shipping , handling)) along with opportunities to reduce internal Supply Chain costs in the areas of Procurement, Inventory Management and Warehouse/Logistics, remains a strategic focus.

Table 1 below shows the historical, bridge and test year forecast of materials costs to support the planned capital and maintenance programs. The first row details the total materials cost required for all THESL programs. The second row details the total materials costs for the Smart Meter Program only. The third row details materials for the THESL Programs exclusive of the Smart Meter Program.

Table 1: Total Materials Costs ($000s)

Inventory Type	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Total THESL	67,155	86,915	81,252	83,572	73,486
Smart Meters	24,878	32,589	23,836	24,246	9,876
Total THESL excluding Smart Meters	42,277	54,326	57,416	59,326	63,610

Note: Costs include all Capital, Operations and Maintenance inventory costs including inflation, and warehouse overhead costs.

Materials costs for the Smart Meter Program are planned to decrease over the test years as the number of meters installed draws to an end by 2010. The budget forecast for the Smart Meter Program is detailed in Exhibit D1, Tab 8, Schedule 5.

The THESL materials expenditures, excluding smart meters, are planned to increase by 28.5 percent in 2007 from 2006. This is mainly due to an increase in the amount of underground cable and associated materials required for the 2007 projects. Annual increases in materials expenditures of 5.7 percent, 3.3 percent and 7.2 percent are planned for 2008 through 2010. These cost increases are mainly for additional cable and associated equipment to support the modernization of the plant assets.

Table 1 includes the forecasted materials cost increases illustrated in Table 2 below for the above periods. Materials costs are impacted by a number of factors such as global supply and demand, currency valuation, metals pricing, crude oil pricing, production capacity limitations. THESL expects to see continued increases in costs over the next three to five years in the areas of metals (copper, steel, aluminum) and petroleum-based products. Materials cost forecasts are based on information gathered from recognized manufacturing associations such as the Electrical Equipment Manufacturers Association

of Canada ("EEMAC") and forecasts from THESL's long-term strategic alliance partners.

These increases will directly impact THESL's costs for products such as transformers, wire and cable and pole line hardware. THESL's forecast for materials cost increases over the major commodity groups are shown in Table 2.

Table 2: Commodity Price Escalators

Commodity	Forecast Cost Incr 06-07	Forecast Cost Incr 07-08	Forecast Cost Incr 08-09	Forecast Cost Incr 09-10
Poles	0%	0%	4%	4%
Transformers	7%	7%	7%	7%
Wire & Cable	5%	5%	5%	5%
Energy Meters	0%	0%	2%	2%
Pole Line Hardware	3%	3%	3%	3%
Overall Average Cost Increase	3.5%	3.5%	3.6%	3.6%

The overall average increase represents all inventory items, required for THESL's work program.

OVERALL EXTERNAL SERVICES COSTS

INTRODUCTION

THESL uses external services to complement its internal capacity to execute work programs. External services represent those services that are generally not available internally. External Services are procured through long term (three- to five-year) services agreements negotiated with a select group of reliable, cost competitive, customer focused service providers in accordance with the Toronto Hydro Procurement Policy guidelines. The contracts are reviewed annually and structured to drive continuous improvement through cost reduction initiatives and the implementation of value added services.

EXTERNAL SERVICES BENEFITS

- allows THESL to focus on core competencies;
- reduces the need to hire and train specialized staff that may be needed only on an occasional basis;
- reduces capital expense on fleet, equipment and facilities; and
- allows THESL to reduce and control operating costs particularly where internal options are less efficient.

EXTERNAL SERVICES

The following is a summary of key external services:

- Civil Construction
- Vegetation Management
- Wood Pole Inspection and Treatment
- Vacuum Truck Services
- Insulator Washing
- Transformer & Cubicle Haulage

- Underground Infrared Inspection
- Overhead Infrared Inspection
- Carbon dioxide (CO_2) Cleaning
- Submersible Vault Washing
- Transformer and Cable Chamber Washing

Civil Construction

Civil Construction encompasses the construction of all civil infrastructure related to THESL's capital investment program as well as the repair and rehabilitation of existing civil assets. Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading and exposure to corrosive salts have a more substantial effect. Some underground cable chambers may only need cleaning or minor repairs i.e., frames, covers, vault doors, grates, etc., while others may require major structural repairs or rebuild to the walls, floor and roof. When prioritizing the replacement of civil infrastructure, capacity planning issues and City-mandated plant relocations are also taken into consideration.

Cable chamber degradation commonly includes corrosion of reinforcing steel, spalling and flaking of the concrete, and rusting of covers or rings. Acidic salts (i.e., sulfates or chlorides) affect corrosion rates. Cable chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a cable chamber system. The overall condition of underground chambers is ranked by taking into account the following factors:

- Condition of floors, walls and roof;
- Existence of asbestos tapes;
- Condition of cable racks;

- Existence of flooding;
- Condition of drain and sump pump;
- Dimensions and available working space; and
- Infra-red scan of splices.

The average life of underground chambers is in the order on 60 to 80 years. When comparing the number of units to be replaced over the next ten years, the Asset Condition Assessment and the age-based model produced different results. The condition-based analysis was believed to provide more realistic results because civil structures in areas not exposed to corrosive, caustic and alkaline environments can last substantially longer than an age-based assessment would indicate.

Vegetation Management

The Vegetation Management ("VM") program is a reliability improvement initiative. Overhead distribution systems are prone to tree branch contacts resulting in feeder outages. To reduce the frequency and impact of tree contacts, a VM program is used to maintain adequate clearance between tree branches and overhead conductors.

Proper pruning of tree branches along overhead distribution routes serves to ensure that tree branches will not grow into THESL's power lines. Good vegetation management also prevents brush contacts thereby reducing outage frequency during normal weather conditions. Past reliability data have shown that the continued use of a vegetation management program significantly reduces the number of tree related outages. Some areas of the city such as the former Toronto district may require more funding for the VM program due to a higher density and more mature tree population. THESL's reliability-based vegetation management efforts are discussed in Exhibit F1, Tab 1, Schedule 3. The goal is to implement a feeder-based management program to address the current increase in tree-related outages and gradually reduce the trend during the next three years.

Wood Pole Inspection/Treatment

Scheduled inspection of wooden poles for decay reduces the risk of exposure to failure, enhances the reliability of the system, and reduces expenditures for capital replacement. It has been determined that the service life of poles with internal and/or external decay can be extended by applying sealants and treatments designed to combat decay and arrest any further degradation of the pole. This program extends the useful lifespan of THESL's pole assets. Other utilities that have been on a ten-year cycle of testing and treatment have achieved a reduction in wooden pole replacements ranging from greater than six percent to less than one percent.

The pole inspection and treatment program also allows THESL to prioritize its Capital replacement program based on the test results received. In addition, the program allows THESL to identify poles that may present a safety risk to the public.

Vacuum Truck Services

Vacuum Truck Services is a reactive type of service used to remove contaminated water/liquid waste from transformer vaults and cable chambers as required. Cable chambers and transformer vaults located in the sidewalk or roadways are regularly subjected to dirt and contamination ingress, including nitrogen compounds from vehicle exhaust, household and commercial liquid waste. Contaminant deposits build up over time resulting in flooding and damage to cable and equipment. A periodic wash and vacuuming program is required to ensure that the equipment and the surrounding containment area are properly maintained to provide for optimal operating conditions.

Insulator Washing Services

Regular insulator washing removes summer dirt and winter salt that accumulate over time. This dirt and salt, combined with moisture, reduces insulation levels and leads to tracking, resulting in flashovers and pole fires. Statistics of insulator failure at THESL over the last three years show an average of:

1) 23 line insulator failures per year with 832 customer hours per failure;
2) 47 lightning arrestor failures with 251 customer hours per failure; and
3) 111 pole top transformer failures with 113 customer hours per failure.

In addition to line insulators, this program includes the washing of all switches, arrestors, terminators, transformer bushings and other circuits which may exist on the pole.

The program is expected to result in reduced power line outages from electrical tracking.

Transformer & Cubicle Haulage

The Transformer & Cubicle Haulage service primarily supports facilities operations and warehouse material handling requirements including moving/relocation of transformers, switchgear cubicles, roof-top equipment and materials within THESL's service area.

Underground Infrared Inspection

It is essential to inspect and maintain the cable chambers routinely in order to improve underground system reliability and reduce the cost for post fault cable replacement. Reliability data show an annual average (over the last three years) of 220 splice failures, 16 pothead failures and 100 leaking PILC cables.

Overhead Infrared Inspection

Infrared inspection of overhead line components identifies potential "hot" spots and allows for corrective measures to be taken before they have an impact on system reliability.

Electrical connections may become loose after some time as a result of load cycling, contamination and physical fatigue. When the connection becomes loose, oxidation penetrates the connection surfaces. This oxidation offers resistance to the flow of electricity creating a hot spot at the point of contact. As a result, the connector will gradually melt and the line will become disconnected. Infrared scanning of the overhead plant detects these hot spots and allows THESL to take corrective action under a controlled condition rather than respond to an unexpected power outage.

CO_2 Cleaning

The CO_2 Cleaning service involves the cleaning of pad-mounted switches, which are typically installed on 27.6 kV feeders. This service work constitutes a reactive follow-up to the infrared inspection of pad-mounted switches, where the need for CO_2 cleaning is identified at hot spots. This program supports THESL's reliability initiatives to reduce/eliminate outages caused by flashed-over, porcelain insulators within PMH switchgear.

Submersible Vault Washing

Submersible vaults are smaller distribution vaults containing transformers and switches. They are typically installed below sidewalks and in boulevards with ventilation grills and consequently are prone to dirt and leaf build-up, which can clog the vault drainage system. They are pressure washed to maintain equipment performance and system reliability.

Transformer and Cable Chamber Washing

Transformer vaults are larger distribution vaults typically installed below sidewalks in the downtown core and along Yonge Street and the Bloor/Danforth corridor. Cable chambers are installed along most roadways to facilitate underground cabling. Transformer and cable chamber washing is both a reactive type of service, and part of planned work. In advance of planned cable work, equipment replacement or maintenance, cleaning may be required to support effective crew activity. On a reactive basis, vaults and chambers may require cleaning as part of a post-fire clean-up or remediation activity.

SERVICE COSTS

Table 1: Total External Service Costs ($000)

Service	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Civil Construction	28,500	35,800	40,700	44,500	52,000
Vegetation Mgt	2,100	3,500	3,600	3,600	3,700
Wood Pole Inspection	73	210	214	219	224
Vacuum Truck Services	32	35	36	37	38
Insulator Washing	62	150	153	157	160
Transformer Haulage	290	295	300	306	312
Infrared Inspection OHD/UG	35	45	85	86	85
CO2 Cleaning	105	65	66	68	69
Vault Washing	64	80	82	84	86
Transformer Washing	10	10	10	10	10
Total	31,000	40,000	45,000	49,000	57,000

Civil Construction - Variance

On a year-over-year basis, the capital requirements for civil construction increase by $7.3 million in 2007, by $4.9 million in 2008, by $3.8 million in 2009, and by a further $7.5 million in 2010. The investment in civil construction services over the period 2007- 2010 aligns with the civil infrastructure required to support the capital investment program.

Vegetation Management – Variance

Vegetation Management program costs increased by $1.4M between 2006 and 2007 to reduce the increased potential of tree-related outages. In 2007, THESL engaged Davies Consulting Inc. to develop a Vegetation Management Model to address increased tree-related outage events. This model fosters a more analytical method to determine vegetation management requirements and supports THESL's increased investment. The years 2007 through to 2010 represent a consistent investment on a year-over-year basis to align with the requirements of this model. The model takes into account several factors including storm-related outages, increased tree planting in the City, customer aversion to tree-trimming, and municipal regulations related to tree-trimming.

Wood Pole Inspection – Variance

The 2006 budget for this program was $180K, with only $73K spent. Six thousand poles were inspected/treated in 2006, as prescribed. However, fewer poles required treatment (to address decay) in 2006. This program remains relatively stable throughout the bridge and test years, with only minor variations in the number of poles being inspected each year. There is an expectation that THESL will need to treat more poles in the coming years to delay the progression of decay.

Vacuum Truck Services – Shows no significant variance 2007-2010.

Insulator Washing – Variance

A late start in the 2006 program resulted in an increase in insulator "flash-overs". A return to more typical expenditures for the annual insulator washing program is represented from 2007 through 2010.

Transformer Haulage – Shows no significant variance 2007-2010.

Infrared Inspection Overhead and Underground – Variance

These three programmes are being combined into one contract. The increase in spending reflects the transition of the overhead three-phase line and PMH switch inspections from internal service providers to external contractors.

CO_2 Cleaning – Shows no significant variance.

Vault Washing – Shows no significant variance.

Transformer Washing – Shows no significant variance.

FLEET AND EQUIPMENT SERVICES

SCOPE OF FLEET AND EQUIPMENT SERVICES ("FES") POLICY

The FES policy has been developed to assist in accomplishing THESL's business plan and is used in conjunction with Supply Chain, Procurement and Safety by Design processes.

The policy provides direction for vehicle purchase, replacement and maintenance and conform to the following requirements:

- *Highway Traffic Act* ("HTA");
- Canadian Motor Vehicle Safety Standards ("CMVSS");
- All related CSA standards, specifically those that relate to aerial devices, hydraulic equipment, tools and rubber cover;
- City of Toronto by-laws (or neighbouring cities if necessary);
- Motor Vehicle Inspection Station ("MVIS") requirements;
- Electrical & Utility Safety Association ("E&USA Rule Book") where applicable; and
- Corporate Health & Safety and Environmental Policies.

REPLACEMENT CRITERIA MODEL

Vehicles are replaced using industry standards as a guideline supplemented by annual condition assessments. Generally, light duty vehicles are initially flagged for the replacement schedule in the period of five to seven years and/or 150,000 kilometer range. Heavy-duty vehicles are assessed in ten-year increments or high mileage (excess of 200,000 km).

In essence, a "first pass" screening process is used based on vehicle age at which time, mileage, engine hours, utilization and power take off ("PTO") hours are documented.

This provides a base line to initiate the capital replacement process. During this time, vehicle utilization is also reviewed and discussions may take place with Business Unit ("BU") Managers on whether a vehicle should be retained, re-allocated or replaced with the same class of vehicle or a completely different vehicle configuration.

At the same time, BU Managers are given the opportunity to adjust their fleet complement for special projects, new hires and changes in job scope.

OPERATING BUDGET

FES develops and manages its operating budget based on the following parameters:

- Capital Vehicle Replacement with approximate in-service dates;
- Historical maintenance records based on Manufacturer requirements, annual licence charges, monthly lease fees and insurance costs;
- Historical data is reviewed over a 12-month time period (June 1 to May 30);
- Annual condition assessment;
- Discussions with Stakeholders to address under-utilized or incorrect vehicles; and
- Outside contracts for body repair, towing and core rebuilding of parts.

FES has adopted a cost recovery model that is re-calculated on an annual basis to ensure that changes in vehicle class and replacement of end-of-life vehicles give an accurate picture of the cost of maintaining the fleet.

FLEET AND EQUIPMENT SERVICES

FLEET AND EQUIPMENT SERVICES ("FES") COSTS

FES maintains a fleet of 684 licenced vehicles and one full-service garage to support THESL's Operation and Capital Work Programs. FES is also responsible for the purchase of new vehicles as part of THESL's normal vehicle replacement program and in addition, provides tools and testing services for THESL and its affiliates. The monthly vehicle charge is based on historical maintenance and repair costs as it relates to vehicle class. These rates are reflected in a Service Level Agreement ("SLA") for each affiliate and are inclusive of all expenses, costs, including depreciation and return on capital, except fuel. Fuel is charged at the end of each month based on consumption.

OPERATING BUDGET

The Total operating budget in FES increases during the bridge and test years. The increase in Fleet costs is attributable to the addition of 20 vehicles in the bridge year to support additional trades and technical Staff and consequently the additional expense to maintain and repair the vehicles.

FES allocates its fleet costs to the business units of THESL and to affiliates based on the cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, FES net budget is neutral after cost allocation (the net costs are included in each business unit or affiliate using the services). Table 1 shows the operating costs for the Fleet, Tool Crib and Glove Lab.

Table 1: Operating Expenses for FES ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Fleet	8,110	9,850	11,060	11,590	12,290
Tool Crib	1,800	630	550	510	490
Glove Lab	1,030	1,290	1,110	1,140	1,180
Total	10,940	11,770	12,720	13,240	13,960

CAPITAL BUDGET

In order to support the distribution asset renewal that is planned over the next ten years, FES has increased its capital budget through the bridge and test years to ensure that vehicles are available in line with industry standards. Vehicles are intended to be replaced on a one for one basis. Vehicle replacement costs are shown in Table 2 below:

Table 2: Capital Budget for FES ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Fleet	5,950	8,290	8,470	7,840	7,870
Tool Crib	150	250	175	200	225
Glove Lab	120	100	125	150	175
Total	6,220	8,640	8,770	8,190	8,270

The increase in the bridge year is attributable the addition of 20 vehicles to the fleet. These vehicles are required to support the additional resources and large capital projects for 2008 and beyond.

Fuelling of Toronto Hydro Vehicles

Toronto Hydro has a multi-year contract for the provision of diesel, bio-diesel and unleaded fuel. As part of an environmental initiative, FES is using bio-diesel fuel for heavy duty trucks at locations that are either fuelled by a mini-tanker or fuelled in THESL yards (i.e., Commissioners and Underwriters). As well, the unleaded fuel contract for Underwriters and Commissioners is a ten percent ethanol-blend to aid in the

environmental impact of the fleet. Approximately 75 percent of the fleet uses an alternate fuel as part of the environmental initiative. The fuel contracts are broken down into multiple vendors for specific requirements as they relate to location and ease of operation. The contracts are as follows:

Diesel (bulk)

- Supplied by Suncor and delivered to two full-service locations (Commissioners and Underwriters); and
- Contract is set for a three year period and a new proposal is currently in process for another multi-year contract.

Bio-Diesel (truck to truck)

- Contract in place with Canada Clean fuels for the supply of truck-to-truck fuelling;
- Currently, Monogram is the only location with truck-to-truck fuelling. Vehicles are fuelled overnight by a mini-tanker and FES has access to a web database to download/view vehicles fuelled and amount of fuel supplied per vehicle; and
- Bio-Diesel mix is set at five percent bio-diesel during the winter months (November to April) and 20 percent bio-diesel during the remainder of the year.

Bio-Diesel (bulk)

- Supplied by Canada Clean Fuels and delivered to two full service locations (Commissioners and Underwriters); and
- 100 percent bio-diesel is used and splash-blended on site with regular diesel fuel in Toronto Hydro's tanks.

Unleaded Fuel (bulk)

- Supplied by Suncor with a ten percent ethanol-blend to meet environmental initiatives; and
- Delivered to two full service-locations (Commissioners and Underwriters).

Unleaded Fuel (Credit Card)

- Contract is in place with Shell Canada based on a lowest compliant bid process; and
- Cards only permit purchase of fuel.

Compressed Natural Gas (CNG)

- Bulk natural gas delivery is provided by normal supply process from underground pipelines;
- Toronto Hydro has three locations with slow-fill overnight fuel stations and are located at Commissioners (24 vehicles), Underwriters (24 vehicles) and Monogram (16 vehicles); and
- Credit cards with Shell Canada are also used for fast-fill of Toronto Hydro vehicles. These cards also only permit the purchase of fuel.

Vehicle Types and Quantity

The Toronto Hydro Fleet consists of a total of 684 licenced vehicles. There are 15 main vehicle classifications and they are broken down as follows with quantities of each:

- Compact Cars – 35
- Minivans – 97
- Full-size Vans – 102
- Pick-up Trucks - 100
- Cube Vans – 72
- Line Truck (no aerial) – 6

- Dump Trucks - 10
- Bucket Trucks (no outriggers) – 92
- Bucket Trucks (Material Handlers) – 41
- Digger/Derrick Trucks – 19
- Cable Trucks - 6
- Crane Trucks – 19
- Trailers (Underground) – 6
- Trailers (Overhead) – 16
- Trailers (Miscellaneous) – 53

Tool Crib

There are three Tool Cribs that are serviced by FES. They are located at Commissioners, Underwriters and Monogram and hold inventory of all small hand tools and major tools used to support the day-to-day operation.

Small hand tools consist of wrenches, pliers, screwdrivers etc. and are generally items that cost less than $1,000. These items are considered operating expenses and are charged back to the requesting RC when issued over the counter. Budgets are populated in each RC based on historical data. Most hand tools are considered un-repairable and are disposed of when they malfunction.

Major tools consist of items that have a value greater than $1,000 and are capitalized at time of issue. The costs for capital tools are covered under the Tool Crib Capital Budget and are also based on historical data. Examples of major tools are hydraulic/battery-powered cutters and presses ($2,000 to $3,000 per unit) as well as portable generators, and Self-Retracting Life Lines ("SRLs") Blocks. Major tools are repaired if considered cost-effective.

Glove Lab

The Glove Lab is located at 500 Commissioners and is responsible for the testing of insulated tools, gloves and line protection. FES allocates its Glove Lab-related costs to the business units of THESL based on the cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, FES net budget for the Glove Lab is neutral after cost allocation (the net costs are included in each business unit or affiliate using the services).

There is also a component of capital purchases within the Glove Lab. These dollars are required to replace rubber cover-up that fails during regular testing, is misplaced or is required for additional work. The budget for the bridge and test years are shown in Table 2 along with the 2006 actuals.

RATE BASE

INTRODUCTION

This exhibit provides the Toronto Hydro-Electric System Limited ("THESL") distribution rate base forecast for the 2008, 2009, and 2010 test years, as well as for the 2006 historical actual and 2007 bridge[1] years, and provides a detailed description of each of the rate base components. For comparative purposes, the 2006 OEB-approved distribution rate base for THESL is also presented in this Exhibit.

In accordance with the OEB's Filing Requirements[2], the rate base used to determine the test year revenue requirements includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital (third party or customer capital contributions). Working capital includes an allowance for working capital.

UTILITY RATE BASE

Utility rate base for THESL's distribution system "rate base" for the historical OEB-approved, bridge, and test years is filed at Exhibit D1, Tab 4, Schedule 1. Summary and continuity statements for gross fixed assets, property construction work in progress ("CWIP"), and accumulated depreciation are provided at Exhibit D1, Tab 6, Schedules 1, 2, and 3, respectively.

The rate base forecast for 2008, 2009, and 2010 is $1,978.9 million, $2,138.6 million, and $2,270.2 million, respectively. Please refer to Exhibit D1, Tab 4, Schedule 1.

[1] Bridge year amounts reflect THESL's forecast.
[2] Filing Requirements for Transmission and Distribution Applications (EB-2006-0170).

Table 1: Distribution Rate Base ($ Millions)

Description	2008 Test	2009 Test	2010 Test
Gross Assets	3,657.8	3,971.4	4,268.8
Accumulated Depreciation	(1,945.3)	(2,100.9)	(2,268.2)
Net Assets	1,712.5	1,870.51	2,000.6
Working Capital	266.4	268.1	269.6
Rate Base	1,978.9	2,138.6	2,270.2

The gross assets balance reflects the capital expenditure programs forecasted for the test years. The Distribution Plant capital programs are described in detail in Exhibit D1, Tab 8, Schedules 1 through 10, and General Plant and Information Technology capital programs are described in Exhibit D1, Tabs 9 and 10, respectively. The justifications for capital projects in excess of $500,000 are filed at Exhibit D1, Tab 8, Schedule 8.

The net asset of the 2006 rate base approved in the EB-2005-0421 was $1,553.6 million. The 2008 net plant of $1,712.5 million is $158.9M or 10.2 percent higher than that last approved, and the 2009, and 2010 net plant of $1,870.5 million and $2,000.6 million are 20.4 percent and 28.8 percent higher than last approved, respectively. Exhibit D1, Tab 5, Schedule 1 provides a discussion of the level of distribution assets as of December 31, 2006, and Exhibit D1, Tab 8, Schedules 1 through 10 describe the distribution investment over the bridge and test years.

Table 2: Continuity of Fixed Assets Summary ($ Millions)

Description	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Opening Balance	3,160.2	3,128.1	3,284.4	3,493.2	3,821.9	4,120.5
In-Service Additions	154.1	163.9	209.8	263.8	298.6	297.5
Reductions	-	(7.6)	(1.0)	(10.0)	-	(1.3)
Transfers	-	-	-	74.9	-	-
Closing Balance	3,314.3	3,284.4	3,493.2	3,821.9	4,120.5	4,416.7
Average Balance	3,237.4	3,206.9	3,389.0	3,657.8	3,971.4	4,268.8

Additions reflect THESL's Distribution Plant capital placed in service each year. These capital programs are described in detail at Exhibit D1, Tab 8, Schedules 1 through 10, and General Plant capital programs are described in Exhibit D1, Tabs 9 and 10. Reductions reflect sales of facilities as identified in Exhibit C2, Tab 2, Schedule 2. Transfers in 2008 reflect smart meter capital expenditures incurred in 2006 and 2007 which were previously recorded as regulatory assets.

THESL has included an allowance for borrowed funds used during construction ("AFUDC") for capital expenditure balance after 2006 as prescribed by the OEB's Accounting Procedures Handbook.

Fixed assets are capitalized at cost which consists of labour, materials, overhead costs, and regulatory approved allowance for funds used during construction applicable to capital construction activities. Overhead costs include warehouse, procurement, engineering, program administration, and other overhead costs. Gross fixed assets costs are offset by customer and third party contributions collected. Net fixed assets are net of

accumulated depreciation based on pre-determined rates, which vary by asset class or type.

Engineering and program administration labour are attributable to projects and programs based on a capitalization rate which reflects THESL's capital program costs as a proportion of THESL's total capital and O&M program costs.

WORKING CAPITAL

In the OEB's RP-2005-0020 / EB-2005-0421 Decision with Reasons, the OEB stated that it expected THESL to develop a lead/lag study in preparation for its next rates application. As a result THESL retained Navigant Consulting, Inc. to undertake this study, which has been filed at Exhibit D1, Tab 15, Schedule 1. The provision for working capital incorporates the methodology stemming from this study.

The working capital requirement for the distribution system is based on the following factors:

- the forecast of OM&A;
- the retail cost of power;
- capital and income taxes, Goods and Services Tax ("GST"), Debt Retirement Charges, and interest on long term debt; and
- the net lead/lag days determined.

The lead/lag study results in a net cash working capital requirement, including the impact of GST, of $266.4 million for the 2008, $268.1 for the 2009, and $269.6 for the 2010 test years. This is a decrease of $41.2 Million, $39.5 million, and $38.0 million, respectively over the $307.6 million approved by the OEB in RP-2005-0020 / EB-2005-0421 for 2006. Details of the working capital requirements for THESL are filed at Exhibits D1, Tab 15, Schedule 2 through 4 for the test years.

Applying the 2006 Electricity Distribution Rate Handbook working capital formula to THESL's forecast of 2008, 2009, and 2010 distribution expenses and cost of power would result in a working capital requirement of $317.8 million for 2008, $319.5 for 2009, and $320.9 for 2010 which are approximately $51.0 million annually over the level requested by THESL.

CONTINUITY OF GROSS ASSETS

Table 1: Year Ending December 2006 – OEB-Approved ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	51.8	-	-	-	51.8	51.8
Distribution System	149.3	9.7	-	-	159.0	154.2
Poles and Wires	2,027.6	105.4	-	-	2,133.1	2,080.4
Line Transformers	505.5	26.3	-	-	531.8	518.7
Services and Meters	150.9	5.5	-	-	156.4	153.6
General Plant	107.7	2.8	-	-	110.5	109.1
Equipment	114.1	5.0	-	-	119.1	116.6
IT Assets	134.6	17.6	-	-	152.2	143.4
CDM	2.5	-	-	-	2.5	2.5
Other Distribution Assets	54.7	3.7	-	-	58.4	56.6
Contributions and Grants	(138.5)	(22.0)	-	-	(160.5)	(149.5)
Total In-Service Assets	**3,160.2**	**154.1**	**-**	**-**	**3,314.3**	**3,237.4**

Table 2: Year Ending December 2007 – Bridge ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	55.3	8.4	(0.3)	-	63.4	59.4
Distribution System	149.1	11.2	-	-	160.3	154.7
Poles and Wires	2,094.0	111.5	-	-	2,205.5	2,149.8
Line Transformers	545.1	45.0	-	-	590.1	567.6
Services and Meters	165.7	12.8	-	-	178.5	172.1
General Plant	102.2	3.9	(0.7)	-	105.4	103.8
Equipment	139.5	13.1	-	-	152.6	146.1
IT Assets	145.9	28.3	-	-	174.2	160.1
CDM	12.3	2.9	-	-	15.2	13.8
Other Distribution Assets	47.3	6.7	-	-	54.0	50.6
Contributions and Grants	(172.0)	(34.0)	-	-	(206.0)	(189.0)
Total In-Service Assets	**3,284.4**	**209.8**	**(1.0)**	**-**	**3,493.2**	**3389.0**

CONTINUITY OF GROSS ASSETS

Table 1: Year Ending December 2006 – Historical Actual ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	53.4	2.1	(0.2)	-	55.3	54.5
Distribution System	142.8	6.3	-	-	149.1	146.0
Poles and Wires	1,996.5	97.5	-	-	2,094.0	2,045.3
Line Transformers	515.4	29.7	-	-	545.1	530.5
Services and Meters	157.3	8.4	-	-	165.7	161.5
General Plant	106.0	3.0	(6.8)	-	102.2	104.1
Equipment	125.8	14.3	(0.6)	-	139.5	132.7
IT Assets	128.3	17.6	-	-	145.9	137.1
CDM	2.0	10.3	-	-	12.3	7.2
Other Distribution Assets	44.8	2.4	-	-	47.3	46.1
Contributions and Grants	(144.2)	(27.8)	-	-	(172.0)	(158.1)
Total In-Service Assets	**3,128.1**	**163.9**	**(7.6)**	**-**	**3,284.4**	**3,206.9**

Table 2: Year Ending December 2007 – Bridge ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	55.3	8.4	(0.3)	-	63.4	59.4
Distribution System	149.1	11.2	-	-	160.3	154.7
Poles and Wires	2,094.0	111.5	-	-	2,205.5	2,149.8
Line Transformers	545.1	45.0	-	-	590.1	567.6
Services and Meters	165.7	12.8	-	-	178.5	172.1
General Plant	102.2	3.9	(0.7)	-	105.4	103.8
Equipment	139.5	13.1	-	-	152.6	146.1
IT Assets	145.9	28.3	-	-	174.2	160.1
CDM	12.3	2.9	-	-	15.2	13.8
Other Distribution Assets	47.3	6.7	-	-	54.0	50.6
Contributions and Grants	(172.0)	(34.0)	-	-	(206.0)	(189.0)
Total In-Service Assets	**3,284.4**	**209.8**	**(1.0)**	**-**	**3,493.2**	**3,389.0**

CONTINUITY OF GROSS ASSETS

Table 1: Year Ending December 2007 – Bridge ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	55.3	8.4	(0.3)	-	63.4	59.4
Distribution System	149.1	11.2	-	-	160.3	154.7
Poles and Wires	2,094.0	111.5	-	-	2,205.5	2,149.8
Line Transformers	545.1	45.0	-	-	590.1	567.6
Services and Meters	165.7	12.8	-	-	178.5	172.1
General Plant	102.2	3.9	(0.7)	-	105.4	103.8
Equipment	139.5	13.1	-	-	152.6	146.1
IT Assets	145.9	28.3	-	-	174.2	160.1
CDM	12.3	2.9	-	-	15.2	13.8
Other Distribution Assets	47.3	6.7	-	-	54.0	50.6
Contributions and Grants	(172.0)	(34.0)	-	-	(206.0)	(189.0)
Total In-Service Assets	**3,284.4**	**209.8**	**(1.0)**	**-**	**3,493.2**	**3,389.0**

Table 2: Year Ending December 2008 – Test ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	63.4	4.9	(0.8)	-	67.5	65.7
Distribution System	160.3	19.2	-	-	179.5	169.9
Poles and Wires	2,205.5	122.6	-	-	2,328.1	2,266.8
Line Transformers	590.1	46.7	-	-	636.8	613.5
Services and Meters	178.5	52.3	-	74.9	305.7	242.1
General Plant	105.4	5.9	(9.2)	-	102.1	103.8
Equipment	152.6	10.4	-	-	163.0	157.8
IT Assets	174.2	20.7	-	-	195.0	184.6
CDM	15.2	0.4	-	-	15.6	15.4
Other Distribution Assets	54.0	8.4	-	-	62.3	58.1
Contributions and Grants	(206.0)	(27.7)	-	-	(233.7)	(219.9)
Total In-Service Assets	**3,493.2**	**263.8**	**(10.0)**	**74.9**	**3,821.9**	**3,657.8**

Table 3: Year Ending December 2009 – Test ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	67.5	1.6	-	-	69.1	68.3
Distribution System	179.5	17.3	-	-	196.8	188.2
Poles and Wires	2,328.1	133.7	-	-	2462.0	2,395.0
Line Transformers	636.8	41.7	-	-	678.5	657.7
Services and Meters	305.7	58.0	-	-	363.7	334.7
General Plant	102.1	5.9	-	-	108.0	105.1
Equipment	163.0	9.4	-	-	172.4	167.7
IT Assets	195.0	38.1	-	-	233.1	214.0
CDM	15.6	0.5	-	-	16.1	15.9
Other Distribution Assets	62.3	12.3	-	-	74.6	68.5
Contributions and Grants	(233.7)	(19.9)	-	-	(253.6)	(243.7)
Total In-Service Assets	**3,821.9**	**298.6**	**-**	**-**	**4,120.5**	**3,971.4**

Table 4: Year Ending December 2010 – Test ($ Millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	69.1	2.1	-	-	71.2	70.2
Distribution System	196.8	17.3	-	-	214.1	205.5
Poles and Wires	2,462.0	143.5	-	-	2,605.3	2,533.6
Line Transformers	678.5	44.7	-	-	723.2	700.9
Services and Meters	363.7	40.9	-	-	404.6	384.2
General Plant	108.0	9.9	(1.3)	-	116.6	112.3
Equipment	172.4	10.8	-	-	183.2	177.8
IT Assets	233.1	25.3	-	-	258.3	245.7
CDM	16.1	0.2	0	0	16.3	16.2
Other Distribution Assets	74.6	22.4	-	-	97.3	86.0
Contributions and Grants	(253.6)	(19.9)	-	-	(273.5)	(263.6)
Total In-Service Assets	**4,120.5**	**297.5**	**(1.3)**	**-**	**4,416.7**	**4,268.8**

DISTRIBUTION EXPENSES – VARIANCE ANALYSIS

DISTRIBUTION EXPENSES SUMMARY

Introduction

Distribution expenses, based on the OEB's reporting categories, for the historical, bridge, and test years are presented below.

Table 1: Distribution Expense Summary ($ Millions)

	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Operation	$ 41.2	$ 45.7	$ 50.9	$ 59.6	$ 65.4	$ 68.7
Maintenance	$ 24.1	$ 36.8	$ 40.8	$ 46.5	$ 48.8	$ 51.3
Billing and Collection	$ 26.1	$ 26.4	$ 26.3	$ 32.4	$ 32.8	$ 33.2
Community Relations (Excl. CDM)	$ 2.9	$ 3.8	$ 3.3	$ 3.6	$ 3.7	$ 3.7
Community Relations (CDM)	$ -	$ 13.1	$ 3.6	$ 1.5	$ 1.6	$ 1.7
Administrative and General	$ 48.3	$ 25.4	$ 30.1	$ 35.1	$ 36.2	$ 36.8
Subtotal	$ 142.5	$ 151.3	$ 155.0	$ 178.7	$ 188.4	$ 195.4
Other Distribution Expenses	$ 19.2	$ 18.2	$ 16.6	$ 17.3	$ 18.1	$ 18.3
Subtotal	$ 161.7	$ 169.4	$ 171.6	$ 196.0	$ 206.5	$ 213.8
Amortization Expense	$ 126.9	$ 124.6	$ 132.4	$ 153.7	$ 160.9	$ 174.4
Total Distribution Expense	$ 288.6	$ 294.0	$ 304.0	$ 349.7	$ 367.3	$ 388.2

Variance Analysis

Table 2: 2006 OEB-Approved versus 2006 Actual ($ Millions)

	2006 Approved	2006 Historical	$ Variance	% Variance
Operation	$ 41.2	$ 45.7	$ 4.5	10.9%
Maintenance	$ 24.1	$ 36.8	$ 12.7	53.0%
Billing and Collection	$ 26.1	$ 26.4	$ 0.4	1.5%
Community Relations (Excl. CDM)	$ 2.9	$ 3.8	$ 0.9	33.2%
Community Relations (CDM)	$ -	$ 13.1	$ 13.1	-
Administrative and General	$ 48.3	$ 25.4	$ (22.9)	(47.5%)
Subtotal	$ 142.5	$ 151.3	$ 8.7	6.1%
Other Distribution Expenses	$ 19.2	$ 18.2	$ (1.0)	(5.4%)
Subtotal	$ 161.7	$ 169.4	$ 7.7	4.8%
Amortization Expense	$ 126.9	$ 124.6	$ (2.3)	(1.8%)
Total Distribution Expense	$ 288.6	$ 294.0	$ 5.4	1.9%

Total 2006 OEB-approved distribution expenses were $288.6 million compared to actual 2006 distribution expenses of $294.0 million, representing an increase of $5.4 million or 1.9 percent. The increase was primarily due to higher community relations expense ($14.0 million) resulting from the delivery of conservation and demand management programs which were separately funded (not included in the 2006 OEB-approved rates), higher maintenance expense ($12.7 million), higher operation expense ($4.5 million), partially offset by lower administrative and general expenses ($22.9 million) and lower amortization expenses ($2.3 million).

Table 3: 2006 Historical versus 2007 Bridge ($ Millions)

	2006 Historical	2007 Bridge	$ Variance	% Variance
Operation	$ 45.7	$ 50.9	$ 5.2	11.4%
Maintenance	$ 36.8	$ 40.8	$ 4.0	11.0%
Billing and Collection	$ 26.4	$ 26.3	$ (0.2)	(0.7%)
Community Relations (Excl. CDM)	$ 3.8	$ 3.3	$ (0.5)	(11.9%)
Community Relations (CDM)	$ 13.1	$ 3.6	$ (9.5)	(72.8%)
Administrative and General	$ 25.4	$ 30.1	$ 4.7	18.4%
Subtotal	$ 151.3	$ 155.0	$ 3.7	2.5%
Other Distribution Expenses	$ 18.2	$ 16.6	$ (1.6)	(8.6%)
Subtotal	$ 169.4	$ 171.6	$ 2.2	1.3%
Amortization Expense	$ 124.6	$ 132.4	$ 7.9	6.3%
Total Distribution Expense	$ 294.0	$ 304.0	$ 10.0	3.4%

Total 2007 forecasted distribution expenses are $304.0 million compared to actual 2006 distribution expenses of $294.0 million, representing an increase of $10.0 million or 3.4 percent. The increase is primarily due to higher amortization expense ($7.9 million), reflecting increased expenditures to renew the distribution assets; increased maintenance expense ($5.2 million) mainly resulting from higher labour costs due to workforce renewal and higher facilities costs; increased administrative and general expenses ($4.7 million) due to higher proportion of THC shared service costs categorized as administrative and general after the THESL reorganization; increased operating expense ($5.2 million) due to workforce renewal, costs to convert water heaters from flat rate billing and increased meter installations; higher maintenance expense ($4.0 million) mainly resulting from higher labour costs due to workforce renewal and higher facilities costs, partially offset by lower community relations expense ($10.0 million) as the conservation and demand management programs were substantially completed in 2006, and lower other distribution expenses ($1.6 million).

Table 4: 2007 Bridge versus 2008 Test ($ Millions)

	2007 Bridge	2008 Test	$ Variance	% Variance
Operation	$ 50.9	$ 59.6	$ 8.7	17.1%
Maintenance	$ 40.8	$ 46.5	$ 5.7	14.0%
Billing and Collection	$ 26.3	$ 32.4	$ 6.1	23.4%
Community Relations (Excl. CDM)	$ 3.3	$ 3.6	$ 0.2	6.3%
Community Relations (CDM)	$ 3.6	$ 1.5	$ (2.0)	(56.9%)
Administrative and General	$ 30.1	$ 35.1	$ 5.0	16.7%
Subtotal	$ 155.0	$ 178.7	$ 23.7	15.3%
Other Distribution Expenses	$ 16.6	$ 17.3	$ 0.7	4.1%
Subtotal	$ 171.6	$ 196.0	$ 24.4	14.2%
Amortization Expense	$ 132.4	$ 153.7	$ 21.3	16.1%
Total Distribution Expense	$ 304.0	$ 349.7	$ 45.7	15.0%

Total 2008 projected distribution expenses are $349.7 million compared to 2007 forecasted distribution expenses of $304.0 million, representing an increase of $45.7 million or 15.0 percent. The increase is mainly due to increased amortization expense ($21.3 million) resulting from the transfer of smart meter assets from a regulatory deferral account and increased capital expenditures for distribution plant and IT assets; increased operation expense ($8.7 million) due to workforce renewal, costs to convert water heaters from flat rate billing and increased meter installations; increased billing and collection expense ($6.1 million) due in part to expected increases in call centre volumes resulting from the anticipated introduction of time of use billing, a larger customer base and higher labour costs; increased maintenance expense ($5.7 million) mainly resulting higher labour costs due to workforce renewal and higher facilities costs, and increased administrative and general expenses ($5.0 million) resulting from increased payroll expenses and higher Finance and Legal shared service charges; partially offset by community relations expense ($1.8 million) due to lower operating costs for the conservation and demand management program.

Table 5: 2008 Test versus 2009 Test ($ Millions)

	2008 Test	2009 Test	$ Variance	% Variance
Operation	$ 59.6	$ 65.4	$ 5.7	9.6%
Maintenance	$ 46.5	$ 48.8	$ 2.2	4.8%
Billing and Collection	$ 32.4	$ 32.8	$ 0.4	1.3%
Community Relations (Excl. CDM)	$ 3.6	$ 3.7	$ 0.1	2.6%
Community Relations (CDM)	$ 1.5	$ 1.6	$ 0.1	5.1%
Administrative and General	$ 35.1	$ 36.2	$ 1.1	3.2%
Subtotal	$ 178.7	$ 188.4	$ 9.7	5.4%
Other Distribution Expenses	$ 17.3	$ 18.1	$ 0.8	4.5%
Subtotal	$ 196.0	$ 206.5	$ 10.4	5.3%
Amortization Expense	$ 153.7	$ 160.9	$ 7.2	4.7%
Total Distribution Expense	$ 349.7	$ 367.3	$ 17.6	5.0%

Total 2009 distribution expenses are $367.3 million compared to 2008 distribution expenses of $349.7 million, representing an increase of $17.6 million or 5.0 percent. The increase is mainly due to increased amortization expense ($7.2 million) resulting from increased capital expenditures for distribution plant and IT assets; increased operation expense ($5.7 million) due to workforce renewal and meter installations, increased maintenance expense ($2.2 million) mainly resulting from higher labour costs due to workforce renewal, and increased administrative and general expenses ($1.1 million) resulting from higher payroll costs.

Table 6: 2009 Test versus 2010 Test ($ Millions)

	2009 Test	2010 Test	$ Variance	% Variance
Operation	$ 65.4	$ 68.7	$ 3.3	5.1%
Maintenance	$ 48.8	$ 51.3	$ 2.6	5.3%
Billing and Collection	$ 32.8	$ 33.2	$ 0.4	1.2%
Community Relations (Excl. CDM)	$ 3.7	$ 3.7	$ 0.1	1.7%
Community Relations (CDM)	$ 1.6	$ 1.7	$ 0.1	7.3%
Administrative and General	$ 36.2	$ 36.8	$ 0.6	1.6%
Subtotal	$ 188.4	$ 195.4	$ 7.1	3.7%
Other Distribution Expenses	$ 18.1	$ 18.3	$ 0.3	1.6%
Subtotal	$ 206.5	$ 213.8	$ 7.3	3.6%
Amortization Expense	$ 160.9	$ 174.4	$ 13.5	8.4%
Total Distribution Expense	$ 367.3	$ 388.2	$ 20.9	5.7%

Total 2010 distribution expenses are $388.2 million compared to 2009 distribution expenses of $367.3 million, representing an increase of $20.9 million or 5.7 percent. The increase is mainly due to increased amortization expense ($13.5 million) resulting from increased capital expenditures for distribution plant and IT assets; increased operation expense ($3.3 million) due to increased meter installations, and increased maintenance expense ($2.6 million) mainly resulting from higher labour costs due to workforce renewal.

DISTRIBUTION ASSETS – VARIANCE ANALYSIS

DISTRIBUTION ASSETS SUMMARY

Introduction

Average distribution fixed assets, net of accumulated depreciation, based on the OEB's minimum reporting groups for the historical, bridge, and test years are presented below.

Table 1: Years Ending December 31 – Historical, Bridge and Test Years
($ Millions)

	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Land and Buildings	51.8	54.5	59.4	65.7	68.3	70.2
Distribution System	154.2	146.0	154.7	169.9	188.2	205.5
Poles and Wires	2,080.4	2,045.3	2,149.8	2,266.8	2,395.0	2,533.6
Line Transformers	518.7	530.5	567.6	613.5	657.7	700.9
Services and Meters	153.6	161.5	172.1	242.1	334.7	384.2
General Plant	109.1	104.1	103.8	103.8	105.1	112.3
Equipment	116.6	132.7	146.1	157.8	167.7	177.8
Information Technology	143.4	137.1	160.1	184.6	214.0	245.7
Conservation and Demand Management	2.5	7.2	13.8	15.4	15.9	16.2
Other Distribution Assets	56.6	46.1	50.6	58.1	68.5	86.0
Contributions and Grants	(149.5)	(158.1)	(189.0)	(219.9)	(243.7)	(263.6)
Gross Assets	3,237.4	3,206.9	3,389.0	3,657.8	3,971.4	4,268.8
Accumulated Depreciation	(1,683.8)	(1,677.8)	(1,804.4)	(1,945.3)	(2,100.9)	(2,268.2)
Net Assets	1,553.6	1,529.1	1,584.6	1,712.5	1,870.5	2,000.6

VARIANCE ANALYSIS

Table 2: Years Ending December 31 OEB-Approved versus 2006 Historical ($ Millions)

	2006 Approved	2006 Historical	$ Variance	% Variance
Land and Buildings	51.8	54.5	2.7	5.2%
Distribution System	154.2	146.0	(8.2)	(5.3%)
Poles and Wires	2,080.4	2,045.3	(35.1)	(1.7%)
Line Transformers	518.7	530.5	11.8	2.3%
Services and Meters	153.6	161.5	7.9	5.1%
General Plant	109.1	104.1	(5.0)	(4.6%)
Equipment	116.6	132.7	16.1	13.8%
Information Technology	143.4	137.1	(6.3)	(4.4%)
Conservation and Demand Management	2.5	7.2	4.7	188.0%
Other Distribution Assets	56.6	46.1	(10.5)	(18.6%)
Contributions and Grants	(149.5)	(158.1)	(8.6)	5.8%
Gross Assets	3,237.4	3,206.9	(30.5)	(0.9%)
Accumulated Depreciation	(1,683.8)	(1,677.8)	6.0	(0.4%)
Net Assets	1,553.6	1,529.1	(24.5)	(1.6%)

Average 2006 OEB-approved average net assets were $1,553.6 million compared to historical 2006 net assets of $1,529.1 million, representing a decrease of $24.5 million or 1.6 percent.

Table 3: Years Ending December 31 OEB-Approved versus 2007 Bridge ($ Millions)

	2006 Approved	2007 Bridge	$ Variance	% Variance
Land and Buildings	51.8	59.4	7.6	14.7%
Distribution System	154.2	154.7	0.5	0.3%
Poles and Wires	2,080.4	2,149.8	69.4	3.3%
Line Transformers	518.7	567.6	48.9	9.4%
Services and Meters	153.6	172.1	18.5	12.0%
General Plant	109.1	103.8	(5.3)	(4.9%)
Equipment	116.6	146.1	29.5	25.3%
Information Technology	143.4	160.1	16.7	11.6%
Conservation and Demand Management	2.5	13.8	11.3	452.0%
Other Distribution Assets	56.6	50.6	(6.0)	(10.6%)
Contributions and Grants	(149.5)	(189.0)	(39.5)	26.4%
Gross Assets	3,237.4	3,389.0	151.6	4.7%
Accumulated Depreciation	(1,683.8)	(1,804.4)	(120.6)	7.2%
Net Assets	1,553.6	1,584.6	31.0	2.0%

Approved 2006 average net assets are $1,553.6 million compared to 2007 net assets of $1,584.6 million, representing an increase of $31.0 million or 2.0 percent.

Table 4: Years Ending December 31 Historical versus 2007 Bridge ($ Millions)

	2006 Historical	2007 Bridge	$ Variance	% Variance
Land and Buildings	54.5	59.4	4.9	9.0%
Distribution System	146.0	154.7	8.7	6.0%
Poles and Wires	2,045.3	2,149.8	104.5	5.1%
Line Transformers	530.5	567.6	37.1	7.0%
Services and Meters	161.5	172.1	10.6	6.6%
General Plant	104.1	103.8	(0.3)	(0.3%)
Equipment	132.7	146.1	13.4	10.1%
Information Technology	137.1	160.1	23.0	16.8%
Conservation and Demand Management	7.2	13.8	6.6	91.7%
Other Distribution Assets	46.1	50.6	4.5	9.8%
Contributions and Grants	(158.1)	(189.0)	(30.9)	19.5%
Gross Assets	3,206.9	3,389.0	182.1	5.7%
Accumulated Depreciation	(1,677.8)	(1,804.4)	(126.6)	7.5%
Net Assets	1,529.1	1,584.6	55.5	3.6%

Historical 2006 average net assets are $1,529.1 million compared to 2007 net assets of $1584.6 million, representing an increase of $55.5 million or 3.6 percent.

Table 5: Years Ending December 31 2007 Bridge versus 2008 Test ($ Millions)

	2007 Bridge	2008 Test	$ Variance	% Variance
Land and Buildings	59.4	65.7	6.3	10.6%
Distribution System	154.7	169.9	15.2	9.8%
Poles and Wires	2,149.8	2,266.8	117.0	5.4%
Line Transformers	567.6	613.5	45.9	8.1%
Services and Meters	172.1	242.1	70.0	40.7%
General Plant	103.8	103.8	-	-
Equipment	146.1	157.8	11.7	8.0%
Information Technology	160.1	184.6	24.5	15.3%
Conservation and Demand Management	13.8	15.4	1.6	11.6%
Other Distribution Assets	50.6	58.1	7.5	14.8%
Contributions and Grants	(189.0)	(219.9)	(30.9)	16.3%
Gross Assets	3,389.0	3,657.8	268.8	7.9%
Accumulated Depreciation	(1,804.4)	(1,945.3)	(140.9)	7.8%
Net Assets	1,584.6	1,712.5	127.9	8.1%

2007 average net assets are $1,584.6 million compared to 2008 average net assets of $1,712.5 million, representing an increase of $127.9 million or 8.1 percent.

Table 6: Years Ending December 31 2008 Test versus 2009 Test ($ Millions)

	2008 Test	2009 Test	$ Variance	% Variance
Land and Buildings	65.7	68.3	2.6	4.0%
Distribution System	169.9	188.2	18.3	10.8%
Poles and Wires	2,266.8	2,395.0	128.2	5.7%
Line Transformers	613.5	657.7	44.2	7.2%
Services and Meters	242.1	334.7	92.6	38.2%
General Plant	103.8	105.1	1.3	1.3%
Equipment	157.8	167.7	9.9	6.3%
Information Technology	184.6	214.0	29.4	15.9%
Conservation and Demand Management	15.4	15.9	0.5	3.2%
Other Distribution Assets	58.1	68.5	10.4	17.9%
Contributions and Grants	(219.9)	(243.7)	(23.8)	10.8%
Gross Assets	3,657.8	3,971.4	313.6	8.6%
Accumulated Depreciation	(1,945.3)	(2,100.9)	(155.6)	8.0%
Net Assets	1,712.5	1,870.5	158.0	9.2%

2008 average net assets are $1,712.5 million compared to 2009 average net assets of $1,870.5 million, representing an increase of $158.0 million or 9.2 percent.

Table 7: Years Ending December 31 2009 Test versus 2010 Test ($ Millions)

	2009 Test	2010 Test	$ Variance	% Variance
Land and Buildings	68.3	70.2	1.9	2.8%
Distribution System	188.2	205.5	17.3	9.2%
Poles and Wires	2,395.0	2,533.6	138.6	5.8%
Line Transformers	657.7	700.9	43.2	6.6%
Services and Meters	334.7	384.2	49.5	14.8%
General Plant	105.1	112.3	7.2	6.9%
Equipment	167.7	177.8	10.1	6.0%
Information Technology	214.0	245.7	31.7	14.8%
Conservation and Demand Management	15.9	16.2	0.3	1.9%
Other Distribution Assets	68.5	86.0	17.5	25.5%
Contributions and Grants	(243.7)	(263.6)	(19.9)	8.2%
Gross Assets	3,971.4	4,268.8	297.4	7.5%
Accumulated Depreciation	(2,100.9)	(2,268.2)	(167.3)	8.0%
Net Assets	1,870.5	2,000.6	130.1	7.0%

2009 average net assets are $1,870.5 million compared to 2010 average net assets of $2,000.6 million, representing an increase of $130.1 million or 7.0 percent.

Table 8: Years Ending December 31 Historical versus 2010 Test ($ Millions)

	2006 Historical	2010 Test	$ Variance	% Variance
Land and Buildings	54.5	70.2	15.7	28.8%
Distribution System	146.0	205.5	59.5	40.8%
Poles and Wires	2,045.3	2,533.6	488.3	23.9%
Line Transformers	530.5	700.9	170.4	32.1%
Services and Meters	161.5	384.2	222.7	137.9%
General Plant	104.1	112.3	8.2	7.9%
Equipment	132.7	177.8	45.1	34.0%
Information Technology	137.1	245.7	108.6	79.2%
Conservation and Demand Management	7.2	16.2	9.0	125.0%
Other Distribution Assets	46.1	86.0	39.9	86.6%
Contributions and Grants	(158.1)	(263.6)	(105.5)	66.7%
Gross Assets	3,206.9	4,268.8	1,061.9	33.1%
Accumulated Depreciation	(1,677.8)	(2,268.2)	(590.4)	35.2%
Net Assets	1,529.1	2,000.6	471.5	30.8%

Between 2006 and 2010 net assets will increase from $1,529.1 million to $2,000.6 million, representing an increase of $471.5 million or 30.8 percent. The increase in gross assets is primarily attributable to expenditures related to poles and wires, services and meters, live transformers, information technology, distribution system, and other distribution assets, partially offset by greater contributions and grants.

Capital investment in poles and wires increased by $488.3 million or 23.9 percent from $2,045.3 million in 2006 to $2,533.6 million in 2010. As described in Exhibit D1, Tab 8, Schedule 1, the increase is primarily due to the need to rehabilitate THESL's underground direct buried and transformer station assets as detailed in the Asset Condition Assessment and 2007-2016 Electrical Distribution Capital Plan.

Investment in line transformer assets will increase from $530.5 million in 2006 to $700.9 million in 2010, resulting in an increase of $170.4 million or 32.1 percent. The 2007-2016 Electrical Distribution Capital Plan describes the investment requirements related to rehabilitation of overhead distribution assets, replacement of distribution transformers,

and rehabilitation of duct systems. Additional information about these investments can be found in Exhibit D1, Tab 8, Schedule 1.

Service and meter assets will increase between 2006 and 2010 from $161.5 million to $384.2 million. This represents an increase of $222.7 million or 137.9 percent. The increase primarily relates to wholesale meter compliance activities and the implementation of the Smart Meter program. Refer to Exhibit D1, Tab 8, Schedules 4 and 5 for additional information.

The increase in information technology assets from $137.1 million in 2006 to $245.7 million in 2010 amounts to $108.6 million or 79.2 percent. As described in Exhibit D1, Tab 10, Schedule 2, the increase is primarily due to the following activities:

- Control Centre Consolidation;
- Outage Management System;
- Distribution Management System;
- Customer Information System upgrade;
- Security Office Establishment;
- Technology Intelligence and Data Management; and
- Core Legacy Application Upgrades.

Distribution assets will increase by $59.5 million or 40.8 percent from $146.0 million in 2006 to $205.5 million in 2010. The increase in distribution assets is primarily due to the need to rehabilitate the system and to improve safety, reliability and customer satisfaction as described in D1, Tab 8, Schedule 1 and D1 Tab 8, Schedule 9.

The increase in other distribution assets from $46.1 million in 2006 to $86.0 million in 2010 amounts to $39.9 million or 86.6 percent and is mainly due to capital contributions

to Hydro One Networks Inc. These contributions relate to the Leaside-Birch transmission upgrade as described in Exhibit D2, Tab 1, Schedule 1.

Contributions and grants will increase between 2006 and 2010 from $158.1 million to $263.6 million. This represents an increase of $105.5 million or 66.7 percent. Realized capital contributions have been based on the amount of energized assets in each year. That is, the increase in contributions and grants is correlated to the increased investment in the distribution assets.

Table 1: Utility Rate Base ($ Millions)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
		Approved 2006 EDR	Historical Actual 2006	2007 Bridge	2008 Test	2009 Test	2010 Test
1	Gross Plant	3,237.4	3,206.9	3,389.0	3,657.8	3,971.4	4,268.8
2	less: accumulated depreciation	1,683.8	1,677.8	1,804.4	1,945.3	2,100.9	2,268.2
3	Net Fixed Assets	1,553.6	1,529.1	1,584.6	1,712.5	1,870.5	2,000.6
4	Working capital	307.6	293.0	262.4	266.4	268.1	269.6
5	Utility Rate Base	**1,861.2**	**1,822.1**	**1,847.0**	**1,978.9**	**2,138.6**	**2,270.2**

Notes:
1. For 2006
Working Capital is calculated as 15% of Cost of power expenses and controllable distribution expenses
2. For 2007 and 2008 - 2010
Working Capital is calculated by applying the working capital factors to the forecast cost components as defined in the Lead Lag Study filed at Exhibit D1, Tab 15, Schedule 1.

DISTRIBUTION FIXED ASSETS

THESL's distribution system is serviced from 35 terminal stations and is comprised of over 26,000 primary switches, 66,000 distribution transformers, 195 municipal substations, over 9,100 kilometers of overhead wires supported by over 159,000 poles and over 7,600 kilometers of underground wires.

CONTROL CENTRE

THESL has one control or operations centre which operates four control districts. The control centre co-ordinates and monitors the distribution of electricity in the control districts, and provides isolation and work protection for internal staff and external customers. The control districts are linked to the distribution system by a voice and data communications network. THESL utilizes supervisory control and data acquisition ("SCADA") systems to monitor and operate the distribution system, and is completing the integration of its two SCADA systems into one master system. THESL recently installed a Distribution Management System ("DMS") to facilitate work process harmonization, centralized monitoring, remote sectionalizing, and isolation or restoration of primary voltage circuits.

TRANSFORMER STATIONS

THESL receives electricity at 35 transformer stations (or terminal stations) at which the voltage is stepped down from either 115kV or 230kV to distribution voltages (27.6 kV or 13.8 kV). Of these stations, 17 are supplied from the older and less efficient 115 kV system while 18 are supplied from the more efficient 230 kV system. The transformer stations contain power transformers and high-voltage switching equipment that are owned by HONI, with the exception of Cavanagh station. Transformer stations also contain low-voltage equipment such as circuit breakers, switches, and station bus work. The level of THESL ownership of the low-voltage equipment varies from completely

THESL-owned to completely HONI-owned. Metering equipment to measure power purchased by THESL from the transmitter is located at these stations. Projects to ensure compliance with metering regulations while reducing costs are described further in Exhibit D1, Tab 8, Schedule 4.

MUNICIPAL STATIONS

In addition to the terminal stations at 27.6 kV or 13.8 kV, there is also a substantial 4.16 kV system supplied from 195 municipal substations that are located in various parts of the City of Toronto. This 4.16 kV system voltage is an old standard and is not expanding. Many of the assets found throughout this system are legacy and often obsolete. In many instances, asset modernization of the system is required. This includes the installation of a 13.8 kV or 27.6 kV system. In doing so, system line losses can be reduced at the higher voltage.

These stations are used to reduce or step-down electricity voltage prior to delivery to distribution transformers. THESL also delivers electricity at distribution voltages directly to certain commercial and industrial customers that own their own substations.

WIRES

THESL distributes electricity through a network of over 9,100 kilometers of overhead wires supported by over 159,000 poles and more than 7,600 kilometers of underground cable, either directly buried, or installed in self-contained cable chamber and duct systems.

DISTRIBUTION TRANSFORMERS

Distribution voltage electricity is distributed from the terminal stations to distribution transformers which are typically located in buildings or vaults or mounted on poles or

surface pads and are used to reduce or step-down voltages to utilization levels for supply to customers. The distribution system includes over 66,000 distribution transformers.

METERS

THESL provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. THESL owns the meters and is responsible for their maintenance and accuracy.

The functional breakout of THESL's asset base is shown in Table 1 below.

Table 1: THESL Distribution Asset Base

Customers	678,000
Net Fixed Assets (NBV YE 2006)	$ 1.6 Billion
Operating Center	1
Distribution Voltages	27.6kV, 13.8kV, 4.16kV
Overhead Primary Feeders	9,100 km
Underground Primary Feeders	7,600 km
Poles	159,000
Terminal Stations	35
Municipal Stations	195
Meters	673,000
Distribution Transformers	66,000

SUMMARY CONTINUITY OF GROSS ASSETS

Table 1: Years Ending December 31 ($ Millions)

	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Opening Balance	3,160.2	3,128.1	3,284.4	3,493.2	3,821.9	4,120.5
In-Service Additions	154.1	163.9	209.8	263.8	298.6	297.5
Disposals	-	(7.6)	(1.0)	(10.0)	-	(1.3)
Transfers	-	-	-	74.9	-	-
Closing Balance	3,314.3	3,284.4	3,493.2	3,821.9	4,120.5	4,416.7
Average Balance	3,237.4	3,206.9	3,389.0	3,657.8	3,971.4	4,268.8

CONTINUITY OF CONSTRUCTION WORK IN PROGRESS ("CWIP")

Table 1: Years Ending December 31 ($ Millions)

	Opening Balance	Net Expenditures[1]	Closing Balance	Average Balance
2006 Approved	29.3	5.9	35.2	32.3
2006 Historical	61.1	6.4	67.5	64.3
2007 Bridge	67.5	3.9	71.4	69.5
2008 Test	71.4	30.8	102.2	86.8
2009 Test	102.2	3.1	105.3	103.8
2010 Test	105.3	13.1	118.4	111.9

[1] Represents capital expenditures net of in-service transfers.

CONTINUITY OF FIXED ASSETS ACCUMULATED DEPRECIATION

Table 1: Years Ending December 31 ($ Millions)

	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Opening Balance	1,619.6	1,616.9	1,738.6	1,870.2	2,020.4	2,181.3
Additions	126.9	124.6	132.4	153.7	160.9	174.4
Reductions	-	(2.9)	(0.8)	(3.5)	-	(0.7)
Transfers	1.6	-	-	-	-	-
Closing Balance	1,748.1	1,738.5	1,870.2	2,020.4	2,181.3	2,355.0
% of Gross Asset Value	52.7%	52.9%	53.5%	52.9%	52.9%	53.3%
Average Balance	1,683.8	1,677.8	1,804.4	1,945.3	2,100.9	2,268.2

ACCUMULATED AMORTIZATION AS A PERCENTAGE OF GROSS FIXED ASSETS

Table 1: Year Ending December 2006 – Actual ($ Millions)

Accumulated Amortization	Ending Balance	Percentage of Gross Assets
Land and Buildings	16.2	29.2%
Distribution System	72.1	48.4%
Poles and Wires	1,029.9	49.2%
Line Transformers	269.7	49.5%
Services and Meters	83.8	50.1%
General Plant	32.0	31.0%
Equipment	111.2	79.7%
IT Assets	112.1	76.2%
Other Distribution Assets	32.1	57.9%
Contributions and Grants	(20.5)	11.9%
Non-Distribution Assets	-	-
Total In-Service Assets	**1,738.6**	**52.9%**

Table 2: Year Ending December 2007 – Bridge ($ Millions)

Accumulated Amortization	Ending Balance	Percentage of Gross Assets
Land and Buildings	17.1	26.9%
Distribution System	76.2	47.5%
Poles and Wires	1,111.2	50.4%
Line Transformers	289.9	49.1%
Services and Meters	89.7	49.8%
General Plant	34.0	32.0%
Equipment	118.3	77.5%
IT Assets	125.6	71.4%
Other Distribution Assets	35.4	55.7%
Contributions and Grants	(27.2)	13.2%
Non-Distribution Assets	-	-
Total In-Service Assets	**1,870.2**	**53.5%**

Table 3: Year Ending December 2008 – Test ($ Millions)

Accumulated Amortization	Ending Balance	Percentage of Gross Assets
Land and Buildings	18.2	26.9%
Distribution System	80.8	45.0%
Poles and Wires	1,195.9	51.4%
Line Transformers	311.8	48.9%
Services and Meters	106.8	34.7%
General Plant	33.2	32.2%
Equipment	126.3	77.4%
IT Assets	143.7	72.9%
Other Distribution Assets	39.0	54.2%
Contributions and Grants	(35.2)	15.1%
Non-Distribution Assets	-	-
Total In-Service Assets	**2,020.5**	**52.9%**

Table 4: Year Ending December 2009 – Test ($ Millions)

Accumulated Amortization	Ending Balance	Percentage of Gross Assets
Land and Buildings	19.4	28.0%
Distribution System	85.9	43.6%
Poles and Wires	1,284.7	52.2%
Line Transformers	335.3	49.4%
Services and Meters	122.6	33.6%
General Plant	35.7	32.8%
Equipment	134.5	78.0%
IT Assets	164.7	69.9%
Other Distribution Assets	42.8	50.8%
Contributions and Grants	(44.1)	17.4%
Non-Distribution Assets	-	-
Total In-Service Assets	**2,181.5**	**52.9%**

Table 5: Year Ending December 2010 – Test ($ Millions)

Accumulated Amortization	Ending Balance	Percentage of Gross Assets
Land and Buildings	20.6	28.9%
Distribution System	91.5	42.7%
Poles and Wires	1,378.5	52.9%
Line Transformers	360.3	49.8%
Services and Meters	141.2	34.8%
General Plant	37.4	31.8%
Equipment	143.0	78.0%
IT Assets	189.3	72.5%
Other Distribution Assets	47.2	44.1%
Contributions and Grants	(53.8)	19.7%
Non-Distribution Assets	-	-
Total In-Service Assets	**2,355.2**	**53.3%**

RATE BASE

SUMMARY OF CAPITAL BUDGET

The capital expenditures presented in this application for 2008-2010 result from a business planning and work prioritization process that reflects risk-based decision-making. Details of the process have been included as part of Exhibit C1, Tabs 4, 6, and 7. The process ensures that appropriate, cost-effective solutions are put into place to meet THESL's objectives of reliability, customer service, asset modernization and safety.

The capital expenditures proposed represent investments that will ultimately become in-service capital assets supporting THESL's business. THESL's investments in capital plant will increase in the coming years, consistent with the capital requirements set out in the 2007-2016 Electrical Distribution Capital Plan filed at Exhibit D1, Tab 8, Schedule 10 of this Application. Exhibit D1, Tab 8 speaks to several material capital projects that are planned for the 2008, 2009 and 2010 test years that will maintain the adequacy, reliability and quality of electricity distribution service to THESL's customers. THESL will conduct this work in accordance to the *Ontario Health and Safety Act* ("OHSA") and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, PCB regulations, and WSIB requirements. THESL is focused on planning, building and maintaining its distribution facilities to meet or exceed service quality and reliability requirements for all of its customers, and intends to make prudent use of existing and new technologies in order to provide efficient and effective levels of customer service.

Specifically, these expenditures are required to:

- purchase, construct and commission specific assets;
- design and develop specific assets;
- make additions to specific assets; and

- achieve asset improvements that result in improvement of capacity, efficiency and useful life span.

THESL's capital budget is presented in two categories: investments in its Electrical Distribution Plant, and investments in its General Plant.

Investment in Electrical Distribution Capital

Investment in Electrical Distribution capital is further broken down into eight investment categories: Sustaining capital, Reactive capital, Customer Connections, Metering, Smart Metering, Engineering Capital, Capital Contributions and Asset Management.

Sustaining Capital

Sustaining Capital investments are undertaken to ensure that the distribution plant continues to operate efficiently, and in a safe and reliable manner. THESL's investments in its distribution plant have been grouped into six main investment areas: underground system replacement of direct buried cable; underground system cable in duct rehabilitation; overhead systems; network system; transformer stations; and municipal stations. These groups of assets, referred to in this filing as Sustaining Capital, are described in further detail in Exhibit D1, Tab 8, Schedule 1.

Sustaining capital investments include replacement of (now) unreliable direct-buried high voltage cables with cable in duct. Although repair is usually much cheaper than replacement, as the frequency of failures increases on a particular segment of cable, reliability and operating cost considerations make replacement the prudent choice. This issue is endemic to large portions of direct-buried distribution plant in Toronto, since the initial investment was made in approximately the same time period as the city's population base expanded.

The sustaining capital investments follow THESL's 2007-2016 Electrical Distribution Capital Plan, Work Prioritization Model, and are based on an understanding of the condition of in-service assets described in the Asset Condition Report filed in Exhibit D1, Tab 8, Schedule 9, and an age-based study. These studies identified a pressing need to renew THESL's underground direct buried distribution system with modern plant, relative to other assets in the distribution system.

THESL submits that sustaining capital investments are prudent, needs-based and delivered on a timely basis to maintain existing levels of service and reliability to our customers.

Reactive Capital

Reactive Capital investments are undertaken to address emerging system requirements, and component or system failures. These investments are typically of an urgent nature and are driven by the need to maintain system reliability to an acceptable standard. The forecast for these investments is based upon historical performance. Reactive capital requirements increase substantially in the bridge year to remedy an increase in system failures resulting from the growing base of aging assets. As investments in underground and overhead assets continue over the next ten years, it is expected that reactive capital investment will decline, and reliability will improve. THESL expects to begin seeing the benefits of past reactive capital investment toward the end of the test years. Details are provided at Exhibit D1, Tab 8, Schedule 2 and Exhibit D1, Tab 8, Schedule 8.

Customer Connections

Customer connections capital investments are required to connect new customers to the distribution system or to enhance service requirements of existing customers. THESL makes these non-discretionary capital investments as part of its license obligations to

ensure it has the capacity to provide a secure and reliable supply of electricity in response to individual customer requirements.

A Customer Connection is defined as the portion of the distribution system used to connect a customer to the main distribution system. It consists of the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with the customer.

A System Expansion is defined as an addition to the distribution system in response to the request for additional customer connections that otherwise would not be made. An Enhancement investment is defined as a modification to the existing distribution system to increase the distribution system capacity to accommodate expected new load.

Customer Additions and System Expansion investments include installation, replacement, and upgrade of service wires and transformers to accommodate additional customer loads. In the case of underground services, the costs for civil work are also included.

Residential service costs are expected to rise through the bridge and test years and average about $15M annually over the period. Commercial customer connections are expected to decline in 2007 and increase through the test years and average about $22M annually over the period. Details are provided at Exhibit D1, Tab 8, Schedule 3-1.

Metering

THESL provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. THESL owns the meters and is responsible for their maintenance and accuracy. THESL is also responsible for funding meter installations at the point where electricity is

transferred from HONI to THESL. The budgeted costs include upgrades to wholesale meter installations to bring them into compliance with IESO requirements, but exclude metering activities covered by the Smart Metering program. Metering details are provided at Exhibit D1, Tab 8, Schedule 4.

Smart Metering

As part of the Provincial initiative for energy conservation and demand management, the Ontario Government has mandated the deployment of smart meters for all electricity consumers in the province by 2010. THESL is responsible for over 678,000 meters within its service territory. Smart meter deployment involves the installation of the meters, the implementation of the required information technology systems, and the development and implementation of the necessary business processes. In 2006 and 2007, the Smart meter costs were tracked in a deferral account and some cost recovery has occurred via rate riders. For 2008-2010, the capital cost for the Smart Meter program has been included in rate base, and the revenue requirement consequences of this capital addition will be treated in the same manner as any other capital investment.

Details are provided at Exhibit D1, Tab 8, Schedule 5.

Engineering Capital

The design, construction and operation of the distribution system are based on sound engineering principles and industry experience. THESL employs Engineers and Technologists to ensure that the distribution plant is designed in a manner that continues to provide efficient and reliable service. Concerted efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards. Although a portion of the costs associated with engineering, design, and operations is expensed, the majority of the

effort, and associated costs, provide benefits beyond the current period and are capitalized.

Engineering capital requirements increase in 2007 by $2.2 million in order to support the engineering and design requirements associated with the increased sustaining capital investment. Increases throughout the test years represent increase in salaries and wages as well as increases to the Gross Capital Expenditure compared to Total Program Expenditure ratio.

Capital Contributions

Capital contributions are contributions required and received from outside sources to finance additions to property, plant and equipment. Customer connection projects that require new facilities to be built on the distribution system or those that require an increase in capacity of the distribution system are the main sources of capital contributions. The size of the contributions, if any, are determined according to prescribed methodologies set out in the Distribution System Code. Capital contributions received are treated as a credit to property, plant and equipment.

New service requests for commercial customers and large residential subdivision developments are subject to an Economic Evaluation Assessment. THESL performs an economic evaluation of the service projects using a discounted cash flow ("DFC") model in accordance with an OEB-accepted methodology. Details of the Economic Evaluation model, its methodology and assumptions are contained in THESL's Conditions of Service document filed at Exhibit C1, Tab 5, Schedule 1.

The economic evaluation is intended to determine whether the stream of future revenues associated with the expansion is sufficient to pay for the capital cost, and ongoing maintenance costs of the distribution system expansion to supply the service. The intent

is to ensure that existing THESL customers are not unnecessarily burdened by the addition of new customers. If the DCF analysis shows a shortfall between the present value of the projected costs and revenues, the customer is required to pay the difference in the form of a capital contribution in accordance with the Distribution System Code. Where a capital contribution is required, the amount and settlement terms are detailed in the customer's Offer To Connect contract.

Customer capital contributions are expected to decline from $23.6 million in 2006 to $19.6 million in 2007 as a result of the new Economic Evaluation Model for Customer Connection and Expansion effective January 23, 2007.

The 2007 investment required for the Customer Connection and Expansion program is $14.8 million net of capital contributions. The increase in spending from 2006 to 2007 is attributable to the decrease in customer capital contributions in 2007. Customer Connection and Expansion spending requirements in the 2008-2010 test years are forecasted to be slightly higher than the historical amount, as shown in Table 1 on page 10.

Asset Management

Asset Management ("AM") capital investments include software tools used to manage asset condition data and analysis tools for system study and planning purposes. The increase in AM investments during the 2008-2010 test years is required for capital contributions to HONI. The contributions total $35 million over the three test years. Refer to Exhibit D2, Tab 1, Schedule 1 for details.

General Plant

General plant is the portion of THESL's plant that is not part of the distribution plant. General plant consists of the following main categories of assets: Information

Technology (hardware and software), transportation equipment and tools; and buildings and facilities (land, building, fixtures and furnishings).

Information Technology

Computer hardware and software technology is used in almost all facets of utility operations and is a key enabler in THESL's initiatives to improve reliability, service, and reduce costs to its customers.

In 2006, the strategic focus for IT revolved around four major projects to meet the business needs: (1) Ellipse Upgrade, (2) Geo-Electric mApping Records ("GEAR"), (3) Smart Meter rollout and (4) launch of the Voice Over Internet Protocol ("VOIP") telephony system upgrade at the Monogram location.

In 2007, Smart Meters continue to be a major project while the other major initiatives are: Customer Information System ("CIS"), Outage Management System ("OMS"), Distribution Management System ("DMS"), Security Program and Technology Infrastructure Program.

As the organization heads into 2008 through 2010, the main focus for IT is to support THESL's objectives to: (1) Modernize the Utility, (2) Be Leaders in Customer Service and (3) Improve Health, Safety, and Development of Employees.

Details are provided at Exhibit D1, Tab 10, Schedules 1 and 2.

Transportation Equipment and Tools

These expenditures involve the management and renewal of transportation equipment used by THESL's workforce. By minimizing equipment downtime, efficiency of the workforce is maximized, thus benefiting customers. Transportation equipment is

managed on a life-cycle basis to meet user needs at the lowest possible cost. Details are provided at Exhibit D1, Tab 9, Schedule 1.

Buildings and Facilities

Projects for buildings and facilities involve the improvement and upgrades needed for continued safe and efficient operation of work centres and offices. The increase is due to the cost of renovating of 14 Carlton and the creation of a new multi-purpose centre at Downsview. Details are provided at Exhibit D1, Tab 9, Schedule 2 and Exhibit C2, Tab 2, Schedule 2.

Table 1 below shows THESL's capital costs for the historical, bridge, and test years.

Table 1: Summary of Capital Budget ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Sustaining Capital					
Underground Direct Buried	7,327	31,961	45,424	54,565	67,101
Underground Rehabilitation	33,112	31,327	30,514	27,188	24,295
Overhead	19,040	22,703	17,339	18,912	21,293
Network	5,625	3,996	4,514	6,187	7,010
Transformer Station	745	9,377	9,304	10,673	10,508
Municipal Substation Investment	5,977	7,008	8,090	6,454	6,568
Sub Total Sustaining Capital	**71,826**	**106,372**	**115,185**	**123,979**	**136,775**
Reactive Work	11,094	14,866	15,550	15,514	15,121
Customer Connections	36,400	34,400	36,360	37,383	38,879
Metering	1,517	8,057	12,964	16,539	14,188
Smart Meter	3,614	0	36,207	34,567	17,643
Engineering Capital	20,960	23,195	26,417	27,051	27,857
Capital Contribution	(23,632)	(19,633)	(19,600)	(19,600)	(19,600)
Asset Management	2,600	300	5,650	10,670	21,190
Total Distribution System	**124,379**	**167,557**	**228,732**	**246,103**	**252,051**
General Plant					
Information Technology	15,210	20,911	27,706	27,227	22,337
Fleet &Equipment Services	6,212	8,640	8,771	8,196	8,269
Facilities	5,689	13, 770	25,340	17,792	22,056
Other (Gear, SCADA, CIS Banner)	4,861	3,228	300	100	900
Total General Plant	**31,974**	**46,549**	**62,117**	**53,315**	**53,562**
AFUDC		2,274	3,325	3,914	4,602
Capital Recoveries	(1,581)	(4,061)	0		
Miscellaneous	2,631	1,120	210	(1,825)	
Total Expenditures	**157,403**	**213,439**	**294,384**	**301,507**	**310,215**

The total capital requirements increase of $56 million in 2007 is attributable to a significant investment requirement to replace unreliable underground direct buried cable and station switchgear, and facility requirements. A further increase of $81 million in 2008 is attributable to underground direct buried cable replacement, smart meter installations (the 2006 and 2007 figures reflect funds already transferred into a regulatory account, whereas 2008 figures do not), facilities requirements for 14 Carlton and IT investments as described earlier. A further increase of $7 million in 2009 is primarily attributable to underground direct buried cable replacement. A further increase of $9 million in 2010 is also primarily attributable to underground direct buried cable replacement. Approximately 80 percent of the capital requirements are attributable to distribution plant investments, with underground direct buried cable replacement representing the largest contributor.

Following its 2006 rate filing, THESL undertook a third party independent assessment of the condition of its assets. That Asset Condition Study, filed at Exhibit D1, Tab 8, Schedule 9, and an age-based analysis were used to prepare a detailed unit replacement plan for key asset classes over a ten-year period. The unit replacement plan formed the basis for a ten-year capital plan titled “2007-2016 Electrical Distribution Capital Plan, January 30, 2007” which was filed with the OEB on February 9, 2007.

The asset condition assessment and age-based studies identified the need for increased investment in all distribution assets over the next ten years to deal with condition or obsolescence, and a pressing need to renew THESL’s underground direct buried distribution system with modern plant.

Approximately 30,000 asset units of distribution equipment were recommended for replacement over the ten-year period and approximately half of that amount will be for the modernization of direct buried distribution systems. The investments proposed for

distribution plant and general plant will maintain the adequacy, reliability and quality of electricity distribution service to THESL's customers.

DISTRIBUTION CAPITAL

SUSTAINING CAPITAL

The sustaining capital investments are needs based and delivered as required to maintain existing levels of service and reliability to our customers.

The sustaining capital expenditures presented in Table 1 below, follow THESL's 2007-2016 Electrical Distribution Capital Plan, Work Prioritization Model, and are based on the condition of in-service assets described in the ACA filed in Exhibit D1, Tab 8, Schedule 9, and an age-based study. These studies identified a pressing need to renew THESL's underground direct buried distribution system with modern plant.

Table 1: Five-Year Plan – Sustaining Capital ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Sustaining Capital					
Underground Direct Buried	7,327	31,961	45,424	54,565	67,101
Underground Rehabilitation	33,112	31,327	30,514	27,188	24,295
Overhead	19,040	22,703	17,339	18,912	21,293
Network	5,625	3,996	4,514	6,187	7,010
Transformer Station	745	9,377	9,304	10,673	10,508
Municipal Substation Investment	5,977	7,008	8,090	6,454	6,568
Sub Total Sustaining Capital	**71,826**	**106,372**	**115,185**	**123,979**	**136,775**

The following Figure 1 represents graphically, the proportion of the investments across the major portfolios.

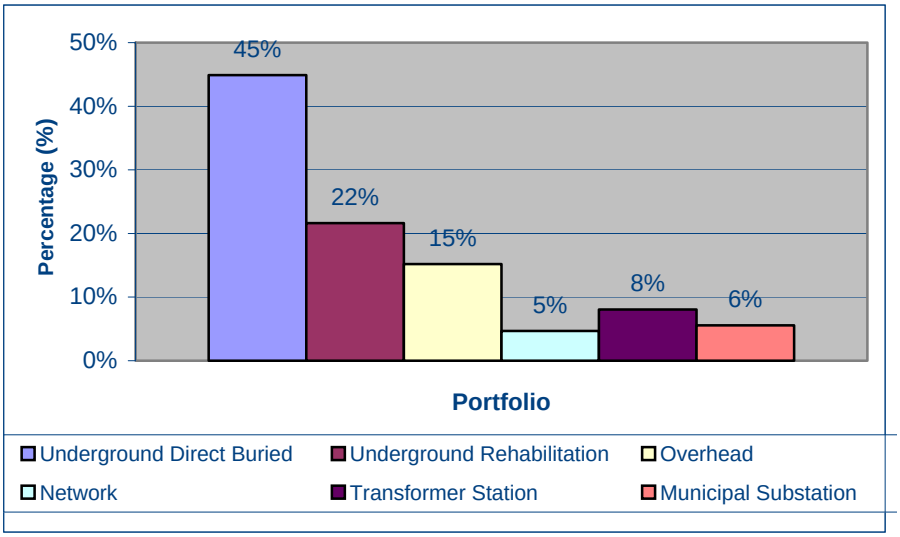


Figure 1: Investment Distribution

Asset condition for major asset classes was quantified through use of Health Indices. In the case of a few specific assets classes at THESL, there are indications that assets may be deteriorating faster than they are being replaced and these require actions beyond routine replacement. Indications of the need for immediate replacement include the increasing failure rates and the poor Health Indices of some classes of asset. For example, direct buried underground cables are a major component that suffers from this deterioration. The assets that require the most significant replacement programs in the next ten years are:

- Direct buried underground cable (61% of the population)
- Underground cable in-duct (31%)
- Automatic transfer switches (63%)
- Station transformers (50%).
- Pole mounted transformers (35%)
- Network transformer/protector units (32%)

Asset age is also a useful measure to indicate the state of the assets and in particular it is useful to determine the geographic concentration of areas requiring investment. Figure 2 below demonstrates the equipment age in the city in 20-year categories.

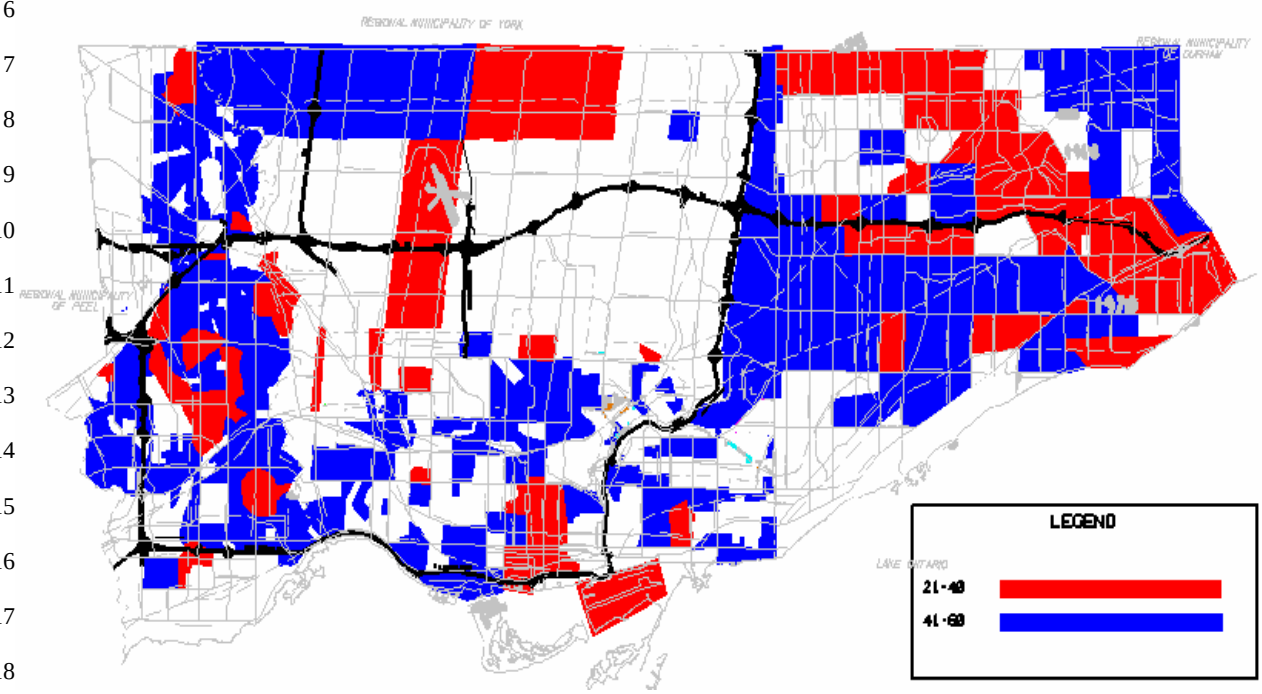


Figure 2: Equipment Age Distribution

Performance statistics such as failure frequency, outage duration, and total customer interruptions are recorded for distribution circuits and equipment. Over the past five years, equipment failures have continued to be the largest outage cause. The following Table 2 illustrates the deteriorating System Average Interruption Frequency ("SAIFI") trend over the last five years due to equipment-related outages:

Table 2: SAIFI Trend (Equipment-Related Outages)

	2002	2003	2004	2005	2006
SAIFI	0.61	0.62	0.70	0.86	0.85

As indicated in the "CEA 2005 Service Continuity Report" (study on Canadian electrical utilities), the average contribution of Defective Equipment to SAIFI during 2005 is 0.48. Comparatively, THESL's Defective Equipment contribution is almost twice as high at 0.85 in 2006. Furthermore, as indicated in the above-mentioned CEA report, defective equipment contributed to 23% of the overall SAIFI figure. In the case of THESL, defective equipment contributed to 43% of the overall SAIFI figure during 2005.

The following Figure 3 illustrates, for comparison purposes, the SAIFI performance of THESL over the last five years.

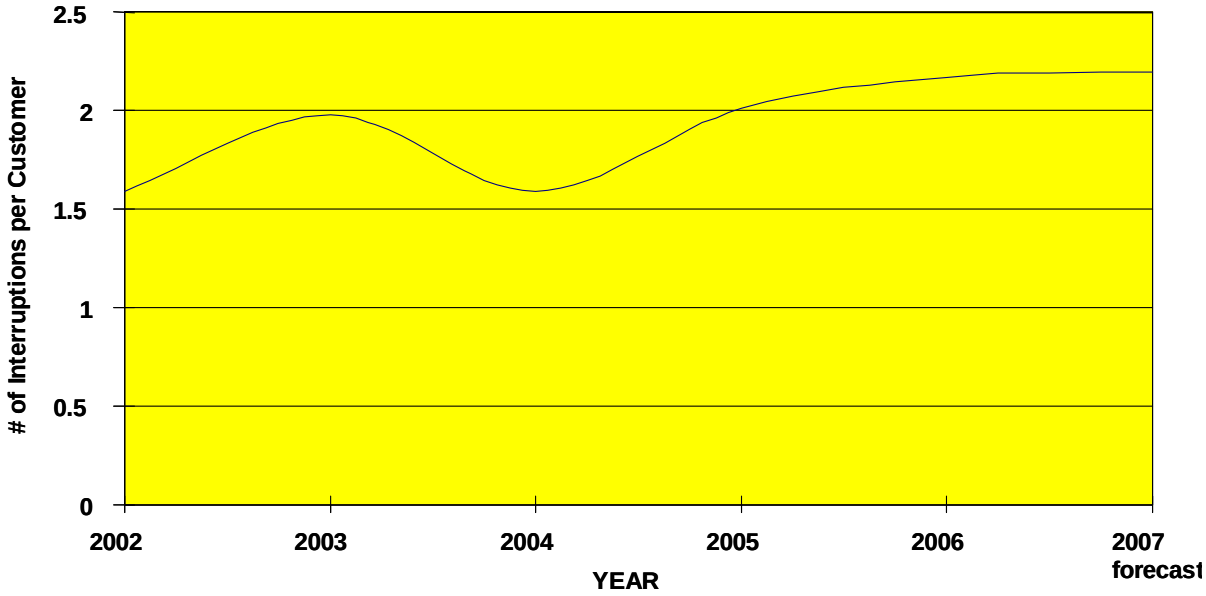


Figure 3: SAIFI Trend

Sustaining capital expenditures for each budget year are derived from a compilation of projects and asset investment requirements using a Work Prioritization Model, and a Long-Term System Planning Process. See Exhibit C1, Tab 6, and Tab 7 for details of the model and the process.

In general, to provide a balanced view of investment requirements, the following factors are considered:

- Corporate Strategic Direction;
- Capital Investment plans;
- Reactive Capital Investment plans;
- Asset Condition Assessment ("ACA") reports;
- Station and feeder load forecasts;
- System reliability data;
- Safety initiatives; and
- Environmental impacts.

In addition, risk analyses were performed which factor in both the potential for and consequence of component failure as equipment reaches the end of its life. Reliability, safety, and the environment are considered as follows:

- Reliability consequences include increasing failure rates and number of customers affected.
- Safety consequences to the public and employees include potential injury or death from equipment failures.
- Environmental consequences include potential damage to the atmosphere, water or soil.

Assets considered for replacement are assessed according to specific criteria embedded in the Work Prioritization Model. Briefly, these criteria include assessments based upon potential reliability improvements (Customer Minutes Out and Customer Interruptions), grid operational flexibility, safety improvements, and cost to repair/install. Once a relative ranking is determined, consideration is given to resource availability and to scheduling logistics. Capacity planning needs are also taken into consideration when determining priorities for replacement areas/circuits, as well as external utility and City-mandated requirements such as distribution plant relocations for road closures.

When projects are under construction, THESL attempts to minimize customer impacts via communication plans to affected neighbourhoods. Typical communication media include community information sessions and project notification letters. In 2007, THESL's "Project Rebuild" campaign was launched as a communication medium for affected neighbourhoods and THESL will likely continue with similar campaigns.

UNDERGROUND DIRECT BURIED CABLE

Generally, underground distribution cables have better reliability than overhead lines since they are not exposed to mechanical or electrical damage from extreme weather, tree contacts or vehicle accidents. Faults on underground cables are usually caused by localized insulation failures. When failures occur, underground cable repair is usually cheaper than replacement. However, as the frequency of failure increases in a given segment, reliability and cost considerations often make replacement the prudent choice, since repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

During the 1970s, cross-linked polyethylene ("XLPE") cables were commonly used in new installations due to their lower costs and easier handling characteristics relative to

other high voltage cable types. However, early generation XLPE cable installations were less reliable due to manufacturing defects and cable joint related issues. Water penetrating into the insulation/conductor barrier (water treeing) was found to be a principal cause of cable failure. Exposing these cables to direct buried environments without the protection of ducts or concrete encasement, further accentuated the deterioration of these cables.

Over the past 30 years many of these problems have been addressed as part of equipment modernization, and modern tree-retardant XLPE cables and accessories are generally considered more reliable. THESL's current practice is to replace old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls to further reduce the rate of deterioration from "water treeing". According to current standards, cable is installed in duct or newly constructed concrete-encased ducts in order to improve reliability of the cable. Cable in duct and concrete-encased ducts enable quicker repair times of faults, thereby reducing the outage duration associated with any future faults**.**

Although new technologies have addressed many of the concerns with earlier vintage XLPE cable, many of the early installations still remain throughout parts of the City; mainly in suburban subdivisions in northeast Toronto. Over the last four years, many direct buried circuits have failed upwards of five times each, causing large numbers of customers to experience outages, with some outages contributing close to one million customer-minutes out. The condition of these cables continues to deteriorate and replacement is indicated. Over the past five years, underground equipment failures have continued to worsen. The following table illustrates the worsening SAIFI trend over the last five years due to underground equipment related outages:

Table 3: SAIFI Trend (Underground Equipment-Related Outages)

	2002	2003	2004	2005	2006
SAIFI (Underground Equipment)	0.35	0.38	0.38	0.49	0.44

THESL used two key criteria to assess the circuits/areas in need of replacement; the number of failures per unit length of installation, and the age of each direct buried cable circuit. As illustrated in the ACA, the average age of the direct buried XLPE cable in Toronto is approximately 30 years. More critical is the fact that about half of this asset class is past its theoretical end-of-life. The ACA also illustrates that presently about two-thirds or almost 800 kilometers of direct buried cable requires replacement over the next ten years. Specifically over the next three years, almost 300 kilometers of direct buried cable is in need of replacement.

In addition to evidence in the ACA, evidence from THESL's "worst feeder list" shows that the majority of the worst ranking circuits are direct buried XLPE cables located in the northeast portion of the city. The worst feeder list is a compilation of circuits with poor historical reliability performance (measured in Total Customer Minutes Out and Total Customer Interruptions).

Replacing direct buried XLPE cable in target areas over the next ten years will contribute significantly to reliability improvement. The areas will be rebuilt using concrete-encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs.

In conjunction with the installation of new concrete-encased primary distribution, consideration is also given to the replacement of other aging assets such as transformers, elbows, fault interrupters, pad-mounted switches, and other assets that are becoming unreliable in order to take advantage of economies of scale and to minimize public disturbances in the future. In addition to infrastructure improvements, target areas will be

redesigned in order to reduce the number of customers experiencing outages when failures occur. For example, circuits utilizing fault interrupters (predominantly in the northeast quadrant of the City) will be redesigned with newer, more reliable, fuses and switchgear.

Table 4 summarizes the total capital requirements for underground direct buried capital investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years.

Table 4: Underground Direct Buried Capital Requirements Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Underground Direct Buried	7,327	31,961	45,424	54,565	67,101

The capital requirements increase throughout the bridge and test years.

A total of $564M is required over the next ten years for capital rehabilitation of underground direct buried cables. Ideally, this would be spread over the ten-year horizon by investing $55M - $60M yearly. However due to resource constraints and the time required to hire the necessary trades and technical staff, and provide the required training, the investment gradually increases over the ten-year period.

The highest priority projects will be undertaken first. Logical project boundaries are taken into account in order to take advantage of economies of scale. The following Figure 5 illustrates the location of projects for the period of 2008-2010.

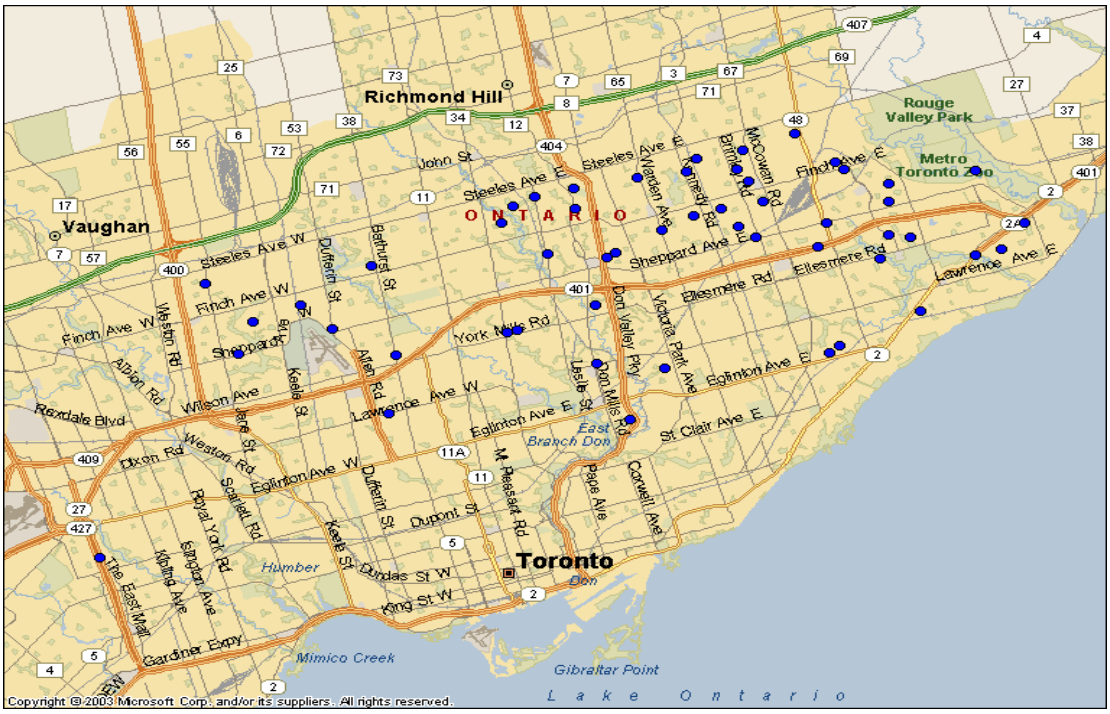


Figure 5: Underground Direct-Buried Projects, 2008-2010

The assets to be replaced in the first three years have demonstrated poor levels of reliability and have aged beyond their serviceable life.

UNDERGROUND REHABILITATION

In many areas in the city and especially in the downtown core, underground cable was installed in concrete-encased ducts. Both paper insulated lead covered ("PILC") and XLPE-type cables have been installed in duct systems throughout the city with majority of the PILC cable installed in the core of the city. For PILC-type cable, the corrosion of the metal sheath and degradation of the oil impregnated paper insulation, and eventual splitting of the lead sheath due to load cycling, creates adverse reliability and environmental impacts.

As noted earlier, as long as the reliability is within acceptable levels, it is virtually always less expensive to repair than to replace cables. In some areas of the city, the reliability has deteriorated, and continued repair has become a costly and unreliable alternative.

THESL used two key criteria to assess the circuits/areas in need of replacement: the number of failures per unit length of installation and the age of each cable circuit. Life expectancy of PILC-type cables is between 50 to 70 years depending on loading and in-service conditions. The ACA suggests that currently approximately one-third (almost 400 kilometers) of PILC cable-in-duct requires replacement over the next ten years. Specifically, over the next three years, 75 kilometers of PILC cable-in-duct is in need of replacement. Although the ACA illustrates the average age of cable-in-duct across the city is about 20 years old, in older areas of the city, the age of cable-in-duct is well above the average.

Due to congestion and aging of the associated cable chambers, a portion of the civil infrastructure will be required to be rebuilt during the replacement of the cable-in-duct. By alleviating congestion, personnel safety will be improved. Furthermore, new construction standards include the installation of a Petro-Barrier. This device will prevent oil from entering storm drains, thereby also benefiting the environment. In conjunction with the installation of new cable-in-ducts, consideration is also given to replace other aging assets that are becoming unreliable such as transformers, elbows, and other assets in order to avoid additional switching operations as well as to reduce multiple work zone set-ups. This will result in minimizing additional future public disturbances.

Table 5 summarizes the total capital requirements for underground rehabilitation investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 5: Underground Rehabilitation Capital Requirements Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Underground Rehabilitation	33,112	31,327	30,514	27,188	24,295

The 2007-2016 Electrical Distribution Capital Plan outlines the requirement for a $210M investment over that ten year period for capital rehabilitation of underground cable in duct systems. Ideally, this would be spread over the ten year horizon by investing $20M to $22M yearly. However, as Apprentices build the required skills by directing their effort to the less complex underground rehabilitation work in the early years, they will then gradually re-direct their efforts to the more complex direct-buried cable replacement work in the latter years.

To summarize priority, logistical end-to-end boundary considerations will be taken into account in order to take advantage of economies of scale and obsolete assets will be replaced with modernized equipment at the same time. The following Figure 6 illustrates the location of projects for the period of 2008-2010.

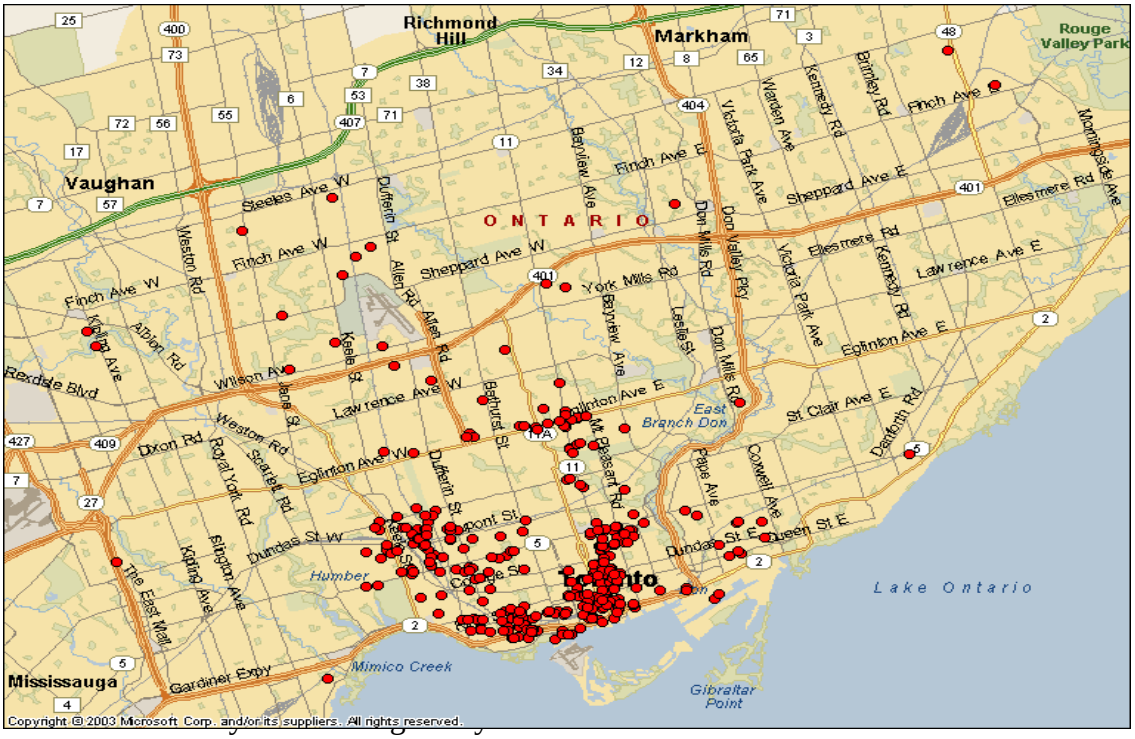


Figure 6: Underground Rehabilitation Projects, 2008-2010

OVERHEAD SYSTEM

THESL's overhead distribution system supplies power to customers at three primary voltages; 27.6 kV, 13.8 kV, and 4.16 kV. The main components of the overhead system include poles, conductors, switches, pole-top transformers, fuses, surge arresters, insulators, and grounding devices.

The deteriorated condition of the overhead distribution plant along with obsolete non-standard equipment, and old poles play an integral part in the overall reliability of the overhead distribution system. Over the past five years, overhead equipment failures have continued to worsen. The following table illustrates the worsening SAIFI trend over the last five years due to overhead equipment related outages:

Table 6: SAIFI Trend (Overhead Equipment-Related Outages)

	2002	2003	2004	2005	2006
SAIFI (Overhead Equipment)	0.24	0.21	0.30	0.33	0.29

In order to attain economic efficiencies, each individual component is not replaced in isolation. Rather, the overhead components are predominantly assessed as areas/circuits.

As illustrated in table ES-1 of the ACA, based upon the condition of the poles, there are almost 1100 poles requiring replacement over the next three years. These poles are distributed relatively uniformly across the city.

Poles

In determining overhead capital expenditures when pole replacement is the primary driver, other factors need to be considered. For example, consideration is given to replace aging like-for-like assets and to convert to a higher primary voltage. Although the conversion option is more expensive, if currently in-service 4 kV stations are scheduled to be decommissioned within the next ten years, or system losses can be reduced at the higher voltage, consideration will be given to voltage conversion.

Transformers

Pole-mounted transformers are used to step down power from primary voltages to utilization voltage. The average age of these assets within THESL is about 40 years and the theoretical end of life for these assets is approximately 50 years. According to the ACA, about 350 pole-mounted transformers are required to be replaced over the next three years.

Switches/Fault Sensing

Primary switches are used throughout the overhead distribution system to allow isolation of line sections or equipment for maintenance, safety, or other operating requirements.

Many of these switches are motor operated for remote operation to enhance speed of switching and operating efficiency. Switches typically corrode around the mechanical linkages or fail under fault conditions. Corrosion occurs primarily in major industrial areas or where harsh environments cause corrosion. Although the environment contributes to rust and corrosion resulting in a critical degradation factor, other conditions such as the load duty, also impact the service life of primary switches. The average service life of a primary switch is approximately 40 years. Existing remote switches in the north central portion of the city are aging, and becoming obsolete and unreliable. They have non-standard communications components, are not designed with fault sensors, and spare parts are difficult to obtain. For these reasons, many of these switches need to be replaced over the next three years. A reduction in the duration of outages on circuits with upgraded switches is expected; Power System Controllers will be able to ascertain the location of faults more quickly, and switch repairs can proceed with standard components.

In general, as assets are replaced in accordance with new "standards" specifications provide for better performance, reduced environmental impacts, and mitigate personnel and public safety impacts. Consideration is also given to specifying assets that will maximize life expectancy within their operating contexts. "Tree-proof" cable is used in heavily treed areas across the city. This is beneficial to the environment since it greatly reduces the extent of pruning required for the affected trees.

Table 7 summarizes the total capital requirements for overhead capital investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 7: Overhead Capital Investments Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Overhead	19,040	22,703	17,339	18,912	21,293

The 2007-2016 Electrical Distribution Capital Plan outlines the requirement for a $182M investment over that ten-year period for rehabilitation of overhead distribution. Ideally, this would be spread over the ten-year horizon by investing $17M to $19M annually. However, a focussed effort on deteriorated pole replacement is required in 2007 with investments in overhead rehabilitation returning to more average levels over the test years.

The highest priority projects will be undertaken first. Logistical end-to-end boundary considerations will be taken into account in order to take advantage of economies of scale, and focus will be in areas where there is limited or no remote switching capabilities in order to improve restoration times and improve customer service. Presently, approximately one-third of overhead switches have remote capabilities. The following Figure 7 illustrates the location of projects for the period of 2008-2010.

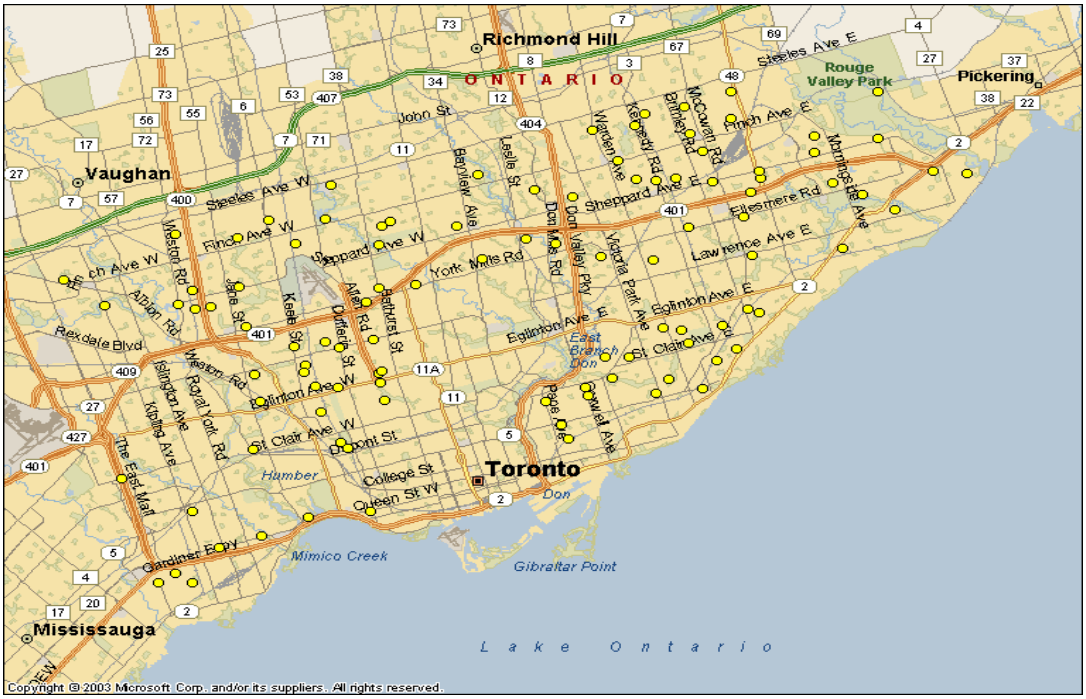


Figure 7: Overhead Projects, 2008-2010

Network Transformers

The network distribution system is a system of secondary cables (below 600V) designed in an interconnected grid, supplied by a number of network transformers. Services fed from the network system are therefore supplied by multiple transformers. This design allows for first contingency operation. That is, one feeder and all associated transformer units can be taken out of service and no other units or cables will become overloaded. The network system is most effectively used to supply urban downtown core areas where the load density is very high, such as along Yonge Street, or Bloor/Danforth.

Network transformers are installed in below grade, self-ventilated concrete vaults. Network transformers have provision for mounting network protectors and are used in the core of the city in a secondary network distribution system. The network protector is a

low voltage, reverse current sensing, auto-reset circuit breaker. It is mounted on the front of the network transformer. The function of the protector is to isolate the transformer from the network when the protector relay senses any reverse current flow.

Protected from most of the natural elements, and able to tolerate partially submerged operation, these units see a longer service life than above-grade units. The end of life for network transformers is usually determined by the extent of the breakdown of core winding insulation and transformer oil leaks through deteriorated gaskets. The life expectancy of a network transformer and protector combination is 30 to 50 years depending upon the number of short circuit operations experienced by the components. Network protector failures that lead to improper fault isolation, may lead to catastrophic transformer failure or a vault fire and may result in widespread outages to commercial customers.

Replacement of aging network transformers and protectors will help to improve service reliability, and reduce the likelihood of environmental and public safety impacts. As illustrated by the ACA, almost 200 units (approximately ten percent) are required to be replaced over the next three years.

Table 8 summarizes the total capital requirements for network capital investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 8: Network Capital Investments Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Network	5,625	3,996	4,514	6,187	7,010

The 2007-2016 Electrical Distribution Capital Plan outlines the requirement for a $58.5M investment over that ten-year period for rehabilitation of network assets. Although there

is variability in spending over the bridge and test years that reflects the age profile of the assets, the expected average investment is about $6M annually.

The highest priority projects are intended to mitigate risk by targeting locations susceptible to high impact events or that contain non-standard equipment. Over 90% of the 200 units to be replaced by 2010 meet these criteria. In order to avoid environmental hazards and to mitigate reliability concerns, further criteria for immediate replacement of this asset class include any locations where the units are found to be leaking oil. The following Figure 8 illustrates the location of projects for the period of 2008-2010.

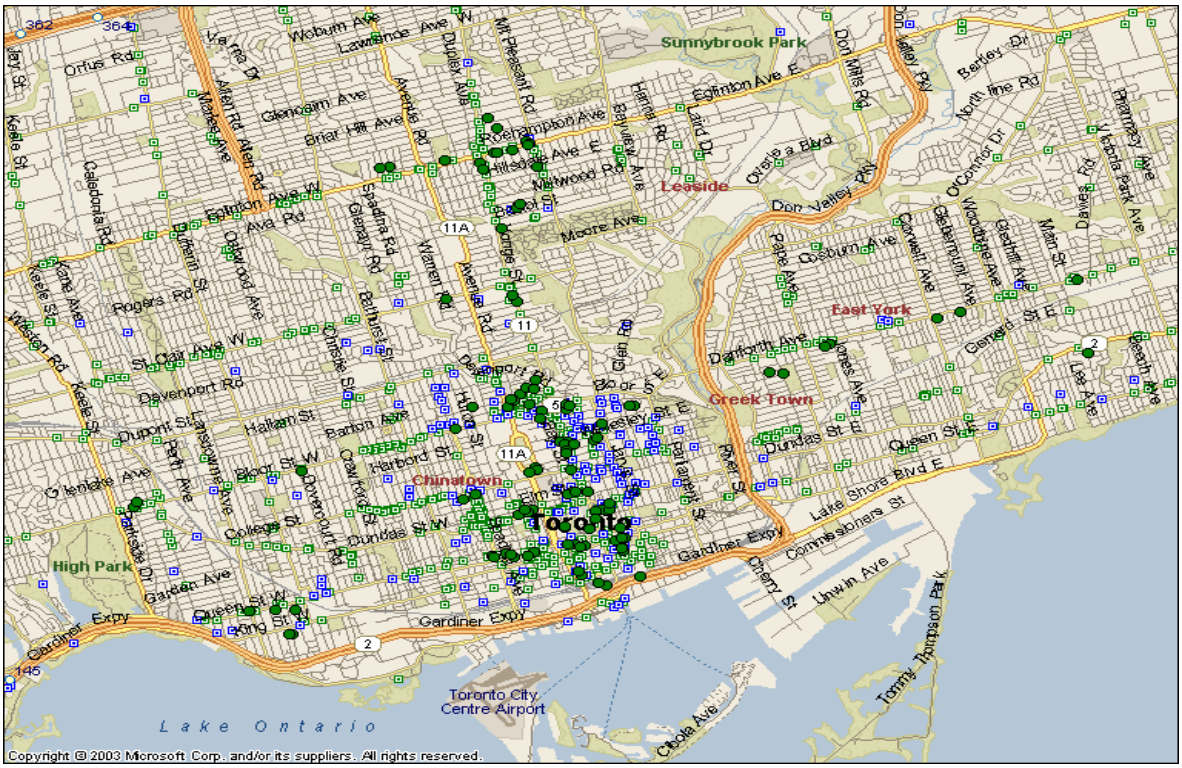


Figure 8: Network Projects, 2008-2010

TRANSFORMER STATIONS (HONI SUPPLY POINTS)

THESL receives power at 35 transformer stations. Of the 35 transformer stations, 19 are owned by HONI, 15 have a mixed ownership of power equipment between HONI and THESL, and one is owned solely by THESL. Seventeen of the stations are supplied at 115 kV and the other 18 are supplied at 230 kV.

These stations are used to obtain power from the transmission system and to transfer it to the distribution system. Their primary function is voltage transformation and switching. Station facilities contain many of the following components: power transformers, circuit breakers, instrument devices, disconnect switches, bus, insulators, power cables, support structures, cable terminators, surge arrestors, station service supplies, supervisory equipment and grounding systems. In general, in cases of mixed station ownership, THESL will own varying number of circuit breakers, and other equipment related to switching functions. Power transformers are generally owned by HONI at these stations.

Circuit Breakers

THESL's circuit breaker population consists of a variety of interrupting technologies: oil, air-blast, air-magnetic, vacuum and sulphur-hexafluoride ("SF6"). As stated in the ACA, there are many factors that affect the condition of a circuit breaker including corrosion, moisture, bush/insulator deterioration, and mechanical wear and tear. The useful life of a circuit breaker can vary between 25 to 50 years. There are almost 30 units across THESL that will reach their end of useful life within the next three years. The oldest technology, oil circuit breakers are one of the technologies targeted for replacement. The units are expensive to maintain as they require the most frequent maintenance intervals. Removal of these units from service decreases the amount of flammable oil present in a station and reduces the amount of oil that may be spilled into the environment.

Switchgear

In indoor stations, circuit breakers are contained in metal-clad housings, called metal-clad switchgear, to reduce space requirements and enhance operational flexibility. All new metal-clad switchgear installations at THESL comply with arc-resistance standards so that failure in one compartment will be contained to that compartment and not spread to adjacent compartments. Personnel safety is increased as the containment prevents injury to personnel in the vicinity. In non-arc-resistant switchgear, an eventful failure in a compartment may damage adjacent compartments or the entire switchgear in an un-repairable way leading to a prolonged outage. Personnel in the proximity of an eventful failure are at risk of injury.

Switchgear degradation is due to deterioration of mechanical mechanisms and interlocks, deterioration of solid insulation, and corrosion. Other non-condition factors such as obsolescence and capability also contribute significantly to the end of life for this asset class. If the fault level on the distribution system rises beyond the rated interrupting capacity of the switchgear for example, the switchgear must be upgraded regardless of its age. The expected life for switchgear is 35 to 50 years under normal in-service conditions.

Ancillary Equipment

Much of the ancillary equipment in the terminal stations is also old and replacement parts are very difficult to source. Increasing the level of automation in order to diagnose and respond to abnormal events is being considered in order to improve performance. Currently, three to five stations per year are scheduled to be retro-fitted.

Plan

Station capital projects address planned refurbishment and component replacement, as well as reactive work. The level of investment required for a selected station will vary as

a function of the age/condition of the station, its performance and any safety and environmental issues identified.

Station condition is determined using the ACA process and on-site reviews. THESL will be replacing switchgear at a rate of three transformer stations per year. In addition to switchgear, a number of other related components must be replaced.

The 2008 investment requirements broken down by component, listed in Table 9 below, are representative of the bridge and test year spending requirements that are summarized in Table 10.

Table 9: Transformer Station Investment Summary ($000s)

Asset Class	2008 Investment
Switchgear	7,562
Transformers (non-power)	215
Circuit breakers	1,169
Batteries and chargers	41
Station decommissioning	-
Fire alarm system	43
Supervisory control/station automation	209
Other	69

Table 10: Transformer Station Capital Investments Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Transformer Station	745	9,377	9,304	10,673	10,508

The 2007-2016 Electrical Distribution Capital Plan outlines the requirement for a $95M investment over that ten year period for replacement of station assets which is reflected in the average spending over the bridge and test years. In 2006, investments were low and no switchgear replacements were done. In 2007, two switchgear replacements were

responsible for $5.6 million and one mobile switchgear unit for another $1 million along with increased investments in other assets.

THESL is able to ramp up capital expenditures for Transformer Stations rapidly. The largest investment type, switchgear replacements, involves significant equipment costs and contract labour.

The highest priority projects will be undertaken first and obsolete assets will be replaced with modernized equipment. The following Figure 9 illustrates the location of projects for the period of 2008-2010.

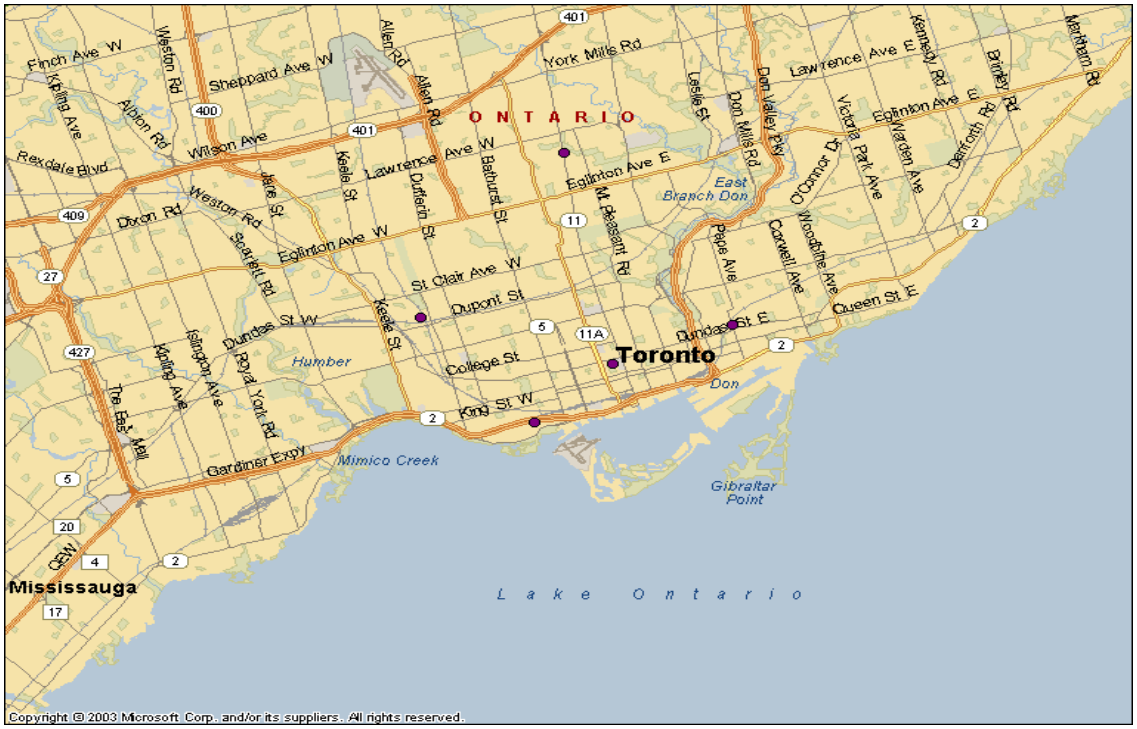


Figure 9: Transformer Station Projects, 2008-2010

MUNICIPAL SUBSTATIONS

Municipal stations receive power from transformer stations via primary distribution feeders and then transform the voltage to either 13.8 kV or 4.16 kV for further distribution. Their primary functions are voltage transformation and switching. They contain much of the same components as transformer stations. THESL operates 152 active municipal stations which are comprised of assets owned and maintained by THESL.

Circuit Breakers and Switchgear

Circuit breakers and switchgear within municipal stations are similar to those in transformer stations as described under Transformer Stations in this Schedule.

Transformers

Municipal station transformers are used to step down the higher distribution voltage levels to lower distribution voltage levels. They are very critical assets from the view of financial and operational risk. The expected end of life for this asset is determined to a great extent by insulation failure. Other end-of-life indicators include condition of bushings, transformer tanks, gaskets, and foundations. Consequences of failure may be significant including customer interruptions for extended periods of time, loss of revenue, and health and safety risks. There are also environmental risks due to oil spills during tank failure.

The expected end of useful life for this asset is 40 to 50 years. As illustrated by the ACA, approximately 30 units will reach their end of life within three years.

Ancillary Equipment

Much of the ancillary equipment in the municipal substations is also old and spare parts are very difficult to purchase for existing equipment. Automating many of these stations is also being considered to improve on reliability and reduction of response time.

Plan

Station condition is determined using the ACA process and on-site reviews. THESL will be refurbishing at least one switchgear and approximately six power transformers each year. In addition, a number of other related components will be replaced.

The 2008 investment requirements broken down by component, listed in Table 11 below, are representative of the bridge and test year spending requirements that are summarized in Table 12.

Table 11: Municipal Station Investment Summary ($000s)

Asset Class	2008 Investment
Switchgear	552
Transformers	854
Circuit breakers	3,720
Batteries and chargers	323
Station decommissioning	159
Fire alarm system	175
Supervisory control/station automation	989
Demand Capital and Tools	625

Table 12: Municipal Substations Capital Investments Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
MS Investment	5,977	7,008	8,090	6,454	6,568

The 2007-2016 Electrical Distribution Capital Plan outlines the requirement for a $60M investment over that ten-year period for rehabilitation of municipal substation assets which is reflected in the average spending over the bridge and test years.

During 2007 and 2008, there is an increase in spending by $1M and $2M respectively in order to address assets currently in very poor condition, representing potentially high impact events to reliability of supply.

Much like transformer stations, the bulk of the investment is attributed to equipment costs, the highest priority projects will be undertaken first, and obsolete assets will be replaced with modernized equipment. The following Figure 10 illustrates the location of projects for the period of 2008-2010.

Figure 10: Municipal Station Projects, 2008-2010

DISTRIBUTION CAPITAL

REACTIVE CAPITAL

Reactive capital investment includes funds for repair/replacements of failed distribution components, and generally does not involve engineering design. Based on past practice, and trending, funds are allocated to capture all expenditures associated with this work. The main goal for allocating these funds is to maintain system reliability to an acceptable standard.

Reactive capital funds allocation is divided into two parts; overhead, and underground. Both categories of work demand asset replacement due to unforeseen failure and therefore are not planned as specific projects. These investments are usually of an urgent nature and are driven by a need to maintain system reliability to an acceptable standard.

The overhead work includes replacement of poles, wires, transformers and overhead line hardware. The forecast for these investments is based upon historical performance and trending data. Details are provided at Exhibit D1, Tab 8, Schedules 8-1, 8-2, and 8-3.

The underground work includes replacement of cables, splices, joints, transformers, switches and civil infrastructure. The forecast for these investments is also based upon historical performance and trending data.

Table 1 summarizes the total capital requirements for reactive capital investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 1: Reactive Capital Investments Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Reactive Work	11,094	14,866	15,550	15,514	15,121

The Reactive capital requirements increase substantially in the bridge year to address a significant increase in system failures resulting from the growing base of aging assets. For 2006, a total of over 7,700 work requests relating to reactive type work were issued. An analysis of the asset classes reveals that a small number of causes accounts for the majority of the deficiencies. Almost 40 percent of the total deficiencies was attributed to underground equipment, composed predominantly of primary cable/terminations and secondary services (over 1100 work requests), pad-mount transformers (over 300 work requests), submersible transformers (over 400 work requests), and vault-related deficiencies (over 1,000 work requests). Additionally, overhead primary conductor repair accounted for almost 900 work requests and pole-related issues also accounted for 900 work requests. Network Transformers / Protectors and Station related assets accounted for less than ten percent of the total work. Although this figure is relatively small, failure of these assets has the potential to significantly impact reliability.

As investments in underground and overhead assets continue over the next ten years, it is expected that reactive capital investment will decline, and reliability will improve. THESL expects to begin to see those benefits toward the end of the test years.

DISTRIBUTION CAPITAL

CUSTOMER CONNECTIONS

Introduction

Customer Connections capital investments are required to connect new customers to the distribution system or enhance the service requirements of existing customers. These are non-discretionary investments made to ensure THESL has the capacity to provide a secure and reliable supply of electricity in response to individual customer requirements.

A Customer Connection is defined as the portion of the distribution system used to connect a customer to the main distribution system. It consists of the assets between the point-of-connect on a distributor's main distribution system and the ownership demarcation point with the customer.

A System Expansion is defined as an addition to the distribution system in response to the request for additional customer connections that otherwise could not be made.

An Enhancement investment is defined as a modification to the existing distribution system to increase the distribution system capacity to accommodate expected new load.

Discussion

In compliance with Section 28 of the *Electricity Act, 1998,* THESL is obligated to connect a building or facility that "lies along" its distribution line. "Lies along" refers to customer property or customer's parcel of land that is directly adjacent to or abuts onto the public road allowance where THESL has distribution facilities of the appropriate voltage and capacity.

Subject to all applicable laws, THESL will make all reasonable efforts in accordance with the provisions of Section 3.5 of its Conditions of Service to connect any services which are the subject of an application for connection.

Customer connections and upgrades are considered demand work as these are driven by individual customer requests. Individual customers or developers may request new service connections or may request a service upgrade due to their expected expansion. These investments are non-discretionary and range from connection of a single residential or small commercial customer (up to 400 amps) to large commercial connections or residential subdivision (including condominiums), and include Generator connections. System expansion due to new customer connections and service upgrades are funded under the Connection Charges as outlined in the Conditions of Service.

Customer Connections and Service Upgrades

Customer Connections and Enhancement projects include installations of service wires and transformers to connect new customers to the electrical distribution system. Also included is the replacement and upgrade of existing service wires and transformers due to the installation of larger wires or transformers to accommodate additional customer loads. In the case of underground services, the costs for civil work are also included.

The need for System Expansion and Reinforcement is identified through system planning studies and load flow analysis. This may include (a) the construction of new feeder or sections of feeders, (b) equipment or conductor upgrade on existing feeders and (c) increase in capacity at a station upstream of the new feeders and upgrades.

Table 1 provides historical, bridge and test years Customer Connections and Service Upgrades expenditures. The volume and funding levels of these programs are based on

known customer requests, as well as historical demand and forecast of economic variables such as Ontario GDP and Ontario Building Permits.

Table 1: Projected 2008-2010 Customer Connections and Service Upgrades Expenditures ($000s)

Description	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Residential	8,700	13,700	14,600	15,000	15,600
Commercial	27,700	20,700	21,900	22,400	23,300
TOTAL Gross Capital	**36,400**	**34,400**	**36,400**	**37,400**	**38,900**
Less: Customer Capital Contributions	(23,600)	(19,600)	(19,600)	(19,600)	(19,600)
Net Customer Connections Capital	**12,800**	**14,800**	**16,900**	**17,800**	**19,300**

The change in the Residential Connection Costs from 2006 to 2007 is due to (a) an update at the end of 2006 to the "Standard Overhead Connection Cost" from $570 (2001 cost) to $850 to reflect the multi-year inflation adjustment, and (b) an additional cost of $460 to account for the equivalent overhead transformation that is allowed under the Distribution System Code.

The reduction in the Commercial Customer Connection Costs from 2006 to 2007 is due to forecast reduction work in Condominiums in 2007.

Customer capital contributions are expected to be $19.6 million for 2007. This is down from the 2006 figure of $23.6 million. Customer Capital Contributions are expected to decrease as a result of the new Economic Evaluation Model for Customer Connection and Expansion effective January 23, 2007.

The 2007 investment required for this program is $14.8 million net of capital contributions. The increase in spending from 2006 to 2007 is attributable to the decrease in customer capital contributions in 2007. The spending requirements in the bridge and test years are forecasted to be slightly increased every year.

Economic Evaluation

New service requests for commercial customers and large residential subdivision developments are subject to an Economic Evaluation Assessment. THESL performs an economic evaluation of the service projects using the discounted cash flow methodology in accordance with OEB accepted methodology. Details of the Economic Evaluation model, its methodology and assumptions are contained in the Conditions of Service document.

The economic evaluation will determine if the stream of future revenues associated with the expansion is sufficient to pay for the capital cost, and ongoing maintenance costs of the distribution system expansion to supply the service. The intent is to ensure that existing THESL customers are not unnecessarily burdened by the addition of new customers. If there is a shortfall between the present value of the projected costs and revenues, the customer must pay the difference in the form of a capital contribution in accordance with the Distribution System Code. Where a capital contribution is required, the amount and settlement terms will be detailed in the customer's "Offer To Connect" contract.

DISTRIBUTION CAPITAL

AVERAGE COST PER CUSTOMER CONNECTION

Connection Charges

When THESL proposes to connect a new customer load or upgrade a connection for an existing customer, an economic evaluation is conducted of the expansion project to determine if the future revenue from the connected customer(s) will pay for the costs pertaining to the expansion. Should the Net Present Value ("NPV") of the costs and revenues associated with the Expansion be less than zero, a capital contribution in the amount of the shortfall is required. The amount of the capital contribution is set out in THESL's Offer to Connect to the customer.

The parameters used in the "Business Economic Model" for the economic evaluation of the expansion project include:

- Enhancement Costs
- New Expansion Costs
- Basic Connection Costs
- Operating, maintenance & administration costs ("OM&A Costs")
- Estimated Incremental Revenues
- Variable Connection Costs

Enhancement Costs

"Enhancement Costs" are calculated using the "estimated incremental demand" and the average distribution system enhancement capital cost of $260.00 per kW. The average enhancement cost represents the aggregated costs, which THESL has incurred over the past three years to increase the distribution system capacity to accommodate new customer loading facilities. Aggregated costs are updated annually.

New Expansion Costs

"New Expansion Costs" are the capital expenditures associated with the installation of new distribution facilities and circuits when these are essential to accommodate new customer loading and which are not intended to be used to serve other customers. If within five years from the connection date, non-forecasted customers are connected to this new plant without any further capital costs, THESL will rebate the initial customer for that customer's portion of the "New Expansion" that is shared with non-forecasted customers.

Basic Connection Costs

The "Basic Connection Cost" is the cost for connecting the standard 30m overhead service including the connection and transformation equipment. The Basic Connection Cost for 2007 is $1,310.00. This figure is updated annually.

Operating, Maintenance & Administration Costs

For the purpose of determining OM&A Costs, THESL uses system average operating, maintenance and administrative expenditures as a proxy for incremental OM&A expenditures, and apportions them as fixed costs (for Rate Class 1 and 2 customers) or as a function of $/kW of demand (for Rate Class 3, 4, and 5 customers). These values are updated annually.

The present average Operating & Maintenance Costs are:

Rate Class 1	$144.91
Rate Class 2	$293.52
Rate Class 3 - non-time of use	$14.2389/kVA
Rate Class 3 - time of use	$14.4238/kVA
Rate Class 4	$18.6229/kVA
Rate Class 5	$14.8076/kVA

The present Administration Cost is 10.7 percent.

Estimated Incremental Revenues

Estimated Incremental Revenues are calculated using the "Estimated Incremental Demand" and the "fixed charge" and the "variable charge" that have been approved by the OEB for the Rate Class applicable to each individual new meter installed in connection with the expansion project. For existing customers, THESL apportions the "fixed charge" based on the ratio between the incremental load and the combined load.

Variable Connection Costs

"Variable Connection Costs" are the actual costs associated with the installation of Connection Assets above and beyond the "Basic Connection Cost". The Variable Connection Costs are paid 100 percent by the customer.

Table 1 below shows the typical Variable Connection Costs for the different service types in each of the customer classes.

1 **Table 1: Typical Variable Connection Costs (2006)**

Class	Description	Type of Service	Typical Variable Connection Fee
1 - Residential - Single Service	Overhead	Overhead Service - Residential (1A)	$850.00 without transformation, $1,310.00 with transformation
	Underground (not requiring transformation facilities on customer's property)	Underground Service - Residential (3A)	$850.00 without transformation, $1,310.00 with transformation
2 - General Service 0 - 50kW	Overhead - Single Service	Overhead Service - Commercial (1B)	$850.00 without transformation, $1,310.00 with transformation
	Underground - Single Service (not requiring transformation facilities on customer's property)	Underground Service - Commercial (3B)	$850.00 without transformation, $1,310.00 with transformation
3A - General Service 50kW - 999kW	Overhead - Single Service (not requiring transformation facilities on	400A, 120/240V (Requiring new estimate)	$980.00 without transformation

Class	Description	Type of Service	Typical Variable Connection Fee
	customer's property)	400A, 120/208V, 3P (Requiring new estimate)	$1,090.00 without transformation
		Up to 100A, 347/600V (Requiring new estimate)	$890.00 without transformation
		* 200A, 347/600V (Requiring new estimate), applicable for upgrades in some area only	$940.00 without transformation
	Underground - Single Service (not requiring transformation facilities on customer's property)	400A, 120/240V	$12,500
		400A, 120/208V, 3P	$12,600
		Up to 100A, 347/600V	$11,500
		200A, 347/600V, applicable for upgrades in some area only	$11,500
		600A, 120/208V, for network system in Toronto Downtown area only	$15,200
		800A, 120/208V, for network system in Toronto Downtown area only	$17,400
	Overhead/Underground Combination (requiring transformation facilities on customer's property)	150 to 1000 kVA Pad (9A1 to 9A5 and 9B1 to 9B3)	$44,000 to $65,000
		Modular vault 300 to 1000kVA (16)	$179,000 to $197,000

Class	Description	Type of Service	Typical Variable Connection Fee
3B - General Service 50kW - 999kW	Underground (Bulk or individual meter)	150 to 1000 kVA Pad (9A1 to 9A5 and 9B1 to 9B3)	$44,000 to $85,000
	Multi-units or townhouse complex with transformation on private property	Subdivision mini-pad Tx & 4 tap boxes	$2,200 per lot without transformation
		Subdivision submersible Tx & 4 tap boxes	$2,200 per lot without transformation
	Underground (Bulk or individual meter) Multi-units or townhouse complex with no transformation on private property	400A, 120/240V with tap box	$2,600 per lot without transformation
3C - Residential Subdivision	Underground Residential Subdivision to individual meter base	Subdivision mini-pad Tx & 4 tap boxes	$2,200 per lot without transformation
		Subdivision submersible Tx & 4 tap boxes	$2,200 per lot without transformation
4 - General Service 1000kW and Up	Overhead/Underground Combination (requiring	1500kVA Pad (9A6, 9B4)	$70,000 to $105,000

Class	Description	Type of Service	Typical Variable Connection Fee
	transformation facilities on customer's property)	Modular vault 1500 to 2500kVA (16)	$216,000 to $220,000
	Overhead/Underground Combination (Customer Owned Substation)	Customer Owned Substation (7A, 7B, 15)	$45,000 to $105,000
5 - Large Users > 5MW	Overhead/Underground Combination (Customer Owned Substation)	Customer Owned Substation (7A, 7B, 15)	$45,000 to $105,000

Average Costs for Customer Connection

The average costs for customer connection, including new services and upgrades to existing services, are calculated from the Capital Expenditures for the types of services and the number of customer connection per year. These costs are THESL gross capital costs to connect customers to THESL's existing infrastructure (refer to Table 2).

For some large services, the costs to connect the customer may occur over many months, or between fiscal years. The reporting of the physical connection is made when the customer is energized. Therefore, the average cost per customer may be skewed in a given year.

Table 2: Customer Connections and Costs

Types of Services	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
# Residential Customers Connected	10,832	9690	9700	9700	9700
# Commercial Customers Connected	181	226	230	230	230
Total Install Cost - Residential Customers ($)	8,682,675	13,756,137	14,614,046	14,974,392	15,574,969
Total Install Cost - Commercial Customers ($)	27,690,495	20,601,153	21,885,954	22,425,608	23,325,031
Average Cost of Residential Customer Connection ($)	802	1,420	1507	1544	1606
Average Cost of Commercial Customer Connection ($)	150,224	91,156	95,156	97,503	101,413

The change in the number of Residential Customers connected from 2006 to 2007 is due to a large increase in the number of Residential Services Upgrades in 2006; this is not anticipated in 2007 and future years.

The low number of Commercial Customer Connections in 2006 was due to the timing of projects completed in 2006. The number of Commercial Customer Connections forecast for 2007-2010 reflects historical demand requirements.

The changes in the Residential Connection Costs from 2006 to 2007 is due to (a) an update at the end of 2006 to the “Standard Overhead Connection Cost” from $570 (2001 cost) to $850 to reflect the multi-year inflation adjustment, and (b) an additional cost of

$460 to account for the equivalent overhead transformation that is allowed under the Distribution System Code.

The reduction in the Commercial Customer Connection Costs from 2006 to 2007 is due to forecast reduction work in Condominiums in 2007.

DISTRIBUTION CAPITAL

METERING

THESL provides its customers with meters through which electricity passes before reaching a distribution board or service panel that directs the electricity to end use circuits on the customer's premises. The meters are used to measure electricity consumption. THESL owns the meters and is responsible for their maintenance and accuracy. THESL is also responsible for funding meter installations at the point where electricity is transferred from HONI to THESL. The budgeted costs include upgrades to wholesale meter installations to bring them into compliance with IESO market requirements and exclude metering activities covered by the Smart Metering program.

Table 1 summarizes the total requirements for metering capital investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 1: Metering Capital Investments Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Metering	1,517	8,057	12,964	16,539	14,188

The increase in funds in 2007-2009 is required to bring the wholesale metering equipment into compliance with IESO requirements.

Wholesale meter installation upgrades, the largest component in the metering capital plan, can be divided into two categories. There are two primary transmission circuits that pass through Toronto – a north circuit and a south circuit. Meter points on the north circuit can be more easily upgraded by relocating the meter point elsewhere in the station. In 2007, 18 points were budgeted at $160,000 each. The budgeted cost is based on a formal proposal delivered by HONI and includes replacement of current and potential

transformers, new metering cabinets, modification to bus support structures, and new landlines. Over the next three years, 49 more points will be upgraded at a similar cost, with the upgrade schedule developed jointly by THESL and HONI.

The upgrades on the south circuit are both more complex and costly. THESL plans to install high voltage metering at the 14 points where the circuit enters Toronto. Doing so will avoid upgrading more than 80 meter points at 22 transformer stations. The budgeted cost to do so includes $15,000,000 over 2008 and 2009. Alternatively, the estimates to upgrade the more than 80 meter points range from $28,000,000 to $45,000,000, if in fact the equipment can be installed anywhere in the space constricted stations. By 2010, the most expensive elements of the job should be completed, so that the capital budget drops significantly. The 2010 costs include the remainder of the meter points to be upgraded, and two power transformer upgrades planned by HONI that will require additional meter points be upgraded to achieve IESO compliance.

The motivation for the meter upgrades is to increase the accuracy of the meter measurements and registration. The existing meter points were not necessarily installed for revenue billing purposes, so some associated equipment is not approved for its current application. Given the large revenue amount generated by these meter points, the IESO developed a set of market rule requirements intended to provide the highest level of confidence possible in the metered values. The upgraded meters also provide additional complex measurements on a more timely and reliable basis, which allows the IESO to better operate the hourly wholesale pricing market.

The Ministry of Energy ("MOE") recently issued a second directive, that all condominium units be equipped with a smart meter by year-end 2010. Many condominiums are currently "bulk-metered", with only one billing meter installed to measure electricity usage. Individual unit consumption is estimated and allocated

through mechanisms such as square foot area, and collected through property management fees. By having THESL install individual meters for each suite, unit owners will become THESL customers and pay for actual metered electricity consumption. A significant consideration with this directive is that the MOE has established suite metering as a competitive meter service provision process, so that condominium corporations can select service providers other than THESL. Consequently, although all condominium units will have a smart meter by year-end 2010, they may not be THESL customers. In consideration of anticipated requests for THESL to provide such services, the forecasted capital spend is $18,500,000 ($3,400,000 in 2008, $5,700,000 in 2009, and $9,400,000 in 2010).

THESL is currently developing an RFP for conversion of bulk-metered buildings to individual smart meters. This RFP is expected to be awarded by August 2007. THESL will again work with the Coalition of Large Distributors ("CLD") where synergies exist, to develop the most standard applications at optimum price points. In addition to the conversion of the existing bulk metered buildings, THESL has revised its Conditions of Service to require individual metering at new developments. THESL is also evaluating business opportunities associated with the conversion of existing bulk metered rental apartment units to individually-metered.

The bulk of the remaining capital budget involves the replacement of interval meters currently installed at approximately 2,500 of THESL's largest customers' facilities. The existing meters are obsolete and upgrades will be required for full compliance with the requirements of the smart meter initiative. Since these accounts already have interval meters, which by definition are considered to be smart meters, this project is not considered to be part of the smart meter initiative. Typical budgeted costs are in the $1,700,000 to $2,200,000 range annually. Meter replacement will start in 2007, with approximately 500 meters being changed. The balance of the work, expected to be

completed by year-end 2010, will involve 650 to 750 meters changed annually, varying slightly according to regulatory requirements and the smart meter mass deployment plan.

DISTRIBUTION CAPITAL

SMART METER INITIATIVE

The Ministry of Energy ("MOE") has directed that a smart meter be installed for all customers by year-end 2010. In 2006, THESL implemented a smart meter deployment plan ("SMIP") to satisfy this direction. The plan was developed after a number of Advanced Metering Infrastructure ("AMI") technologies were pilot tested in 2005. In association with the MOE, THESL worked with members of the Coalition of Large Distributors ("CLD") to develop a joint procurement and installation strategy. In May 2006, the CLD posted to the MERX website a document entitled "Request for Pre-Qualifications for Advanced Metering Infrastructure (AMI) Procurement and Installation". After reviewing more than 20 responses, five vendors were designated as being qualified to deliver either smart meter products, installation services, or both. CLD members then individually negotiated with the five vendors to determine purchase requirements.

The THESL plan initially focuses on residential installations, primarily in the suburban area surrounding the downtown core. Table 1 summarizes the total capital requirements and forecasted installation volumes for smart meter capital investments for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 1: Forecast Volumes and Expenditures

Units	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	Totals
Residential	190,000	210,000	100,000	100,000	33,000	633,000
Commercial < 200 kW	6,500	6,000	23,000	23,000	14,500	73,000
Commercial >200 kW	1,000	1,500	1,000	1000	500	5,000
Total SM units	197,500	217,500	124,000	124,000	48,000	711,000
Capital Spend Forecast ($000s)[1]	34,110	43,669	36,207	34,567	17,643	166,197

The plan focus shifts to the downtown core at approximately year-end 2007, and from residential meters to commercial meters. Since there are fewer commercial meter installations, which take longer to complete and require greater scheduling co-ordination, the overall forecasted installation volumes begin to drop significantly. By year-end 2010, all currently installed residential and commercial meters will be replaced by a smart meter, and all new services will have a smart meter installed at the time of initial connection.

Year-end 2007 also coincides with the expiration of the contract that was negotiated following the original RFPQ. THESL will initiate another competitive purchase process to support the SMIP.

In conjunction with the installation of smart meters and beginning with 2006 AMI technology selection, THESL began its preparation of information technology as necessary to support smart meters. Such technology provides the “back-office” systems support for installation and lifecycle management of smart meters, remote data collection as well as the integration of smart meter information with billing, customer information and provincial Meter Data Management/Repository (“MDM/R”) processes.

[1] 2006 and 2007 costs were captured in a variance account and paid for through rate riders. Costs for 2008-2010 are included in rate base and include engineering capital.

The information technology focus in 2006 centred on meter reading and meter installation. In the bridge 2007 year, efforts turned to Time of Use billing preparations, the presentation of smart meter information to customers and preparations for integration with MDM/R. For 2008, 2009 and 2010, efforts will be centred on aligning THESL capabilities with evolving requirements and working to reduce ongoing smart meter operating costs through appropriate process automation and use of technology. Continued regulatory guidance on Time of Use billing, presentment of smart meter information to customers and integration requirements with the MDM/R are anticipated and costs to respond to this guidance are included. Capital expense related to new Wide Area Network communications infrastructure to reach smart meters will be designed to reduce long-term operational costs and is considered under IT investment.

DISTRIBUTION CAPITAL

ENGINEERING CAPITAL

The design, construction and operation of the distribution system are based on sound engineering principles and industry experience. THESL employs Engineers and Technologists to ensure the distribution plant is designed accordingly and continues to provide efficient and reliable service. Although a portion of the costs associated with engineering, design, and operations is expensed, the majority of the effort, and associated costs, provide benefits beyond the current period and are capitalized.

Table 1 summarizes the total capital requirements for Engineering capital for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 1: Engineering Capital ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Engineering Capital	20,960	23,195	26,417	27,051	27,857

Engineering capital requirements increase throughout the bridge and test years in order to support the engineering and design requirements associated with the increased capital investment. Increases include salaries and wages as well as the relative shift towards increased capital spending, and decreased operating costs (Gross Capital Expenditure compared to Total Program Expenditure ratio).

DISTRIBUTION CAPITAL

ASSET MANAGEMENT

Asset Management capital investments include software tools used to manage asset condition data and analysis tools for system study purposes.

Table 1 summarizes the total capital requirements for Asset Management for the 2008, 2009, and 2010 test years, as well as the historical and bridge years:

Table 1: Asset Management Summary ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Asset Management	2,600	300	5,650	10,670	21,190

Historical spending included funds for re-labelling of distribution equipment and converting locking devices on equipment to more secure technology. The increase in funds required from 2008-2010 are primarily attributed to capital contributions to HONI. Refer to Exhibit D2 Tab 1 Schedule 1 for further details.

PROJECTS $500K AND OVER FOR 2008

UNDERGROUND – DIRECT BURIED

Table 1: Underground – Direct Buried Projects

Project Number	Project Title	Estimated Cost ($)
E07316	Underground rehabilitation at Sandhurst Circle area	3,267,000
E07317	Underground rehabilitation at Murison Boulevard area	5,118,000
E07319	Underground rehabilitation at Wintermute, Bamburgh Circle area	4,768,000
E07323	Underground rehabilitation at Fundy Bay, Ambercroft Boulevard area	6,801,000
E07355	Underground rehabilitation at Tange Briarway and Leslie Street	684,000
E07358	Underground rehabilitation at Sheppard Avenue, Quantrell Trail area	6,010,000
E08300	Port Royal NT63M4 UG Repl.SE.part, Electrical	784,196
E08118	Underground rehabilitation at Pinetree Subdivision	4,057,000
E08119	Underground Rehabilitation at Morningside, Sewells Area	2,726,000
E08124	Underground Rehabilitation of feeder NY51M25: Shawnee and Nootka	1,760,000
E08141	Underground Rehabilitation SCNT63M6 at Hartleywood area	1,766,000
E08161	Feeder Conversion SCYHF1 & SCYHF3: Military Tr & Morningside Avenue	886,000
Overall Cost		38,627,196

PROJECT #: E07316

Business Case Summary

Project Title: Underground rehabilitation at Sandhurst Circle area

Estimated Cost: $3,267,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT63M8.
- To rebuild the subdivisions bounded by McCowan Rd, McNicoll Avenue, Sandhurst Cir and White Heather Boulevard with all assets constructed to standard.

Description:

- There have been four unplanned outages in this area over the past two years.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the Asset Condition Assessment ("ACA"), there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with fuses and switches within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E07317

Business Case Summary

Project Title: Underground rehabilitation at Murison Boulevard area

Estimated Cost: $5,118,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M3.
- To rebuild the subdivisions bounded by Sheppard Avenue, Milner Avenue, Neilson Rd. and Morningside Avenue with all assets constructed to standard.

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- This project will address reliability concerns of feeder NT47M3 which is on the THESL worst performing feeder list.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E07319

Business Case Summary

Project Title: E07319 Underground rehabilitation at Wintermute, Bamburgh Circle area

Estimated Cost: $4,768,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA502M21
- To rebuild the subdivisions bounded by Warden Avenue., Birchmount Rd, Steeles Avenue and McNicoll Avenue with all assets constructed to standard.

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree

retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with switches and fuses within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E07323

Business Case Summary

Project Title: Underground rehabilitation at Fundy Bay, Ambercroft Boulevard area

Estimated Cost: $6,801,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA502M21
- To rebuild the subdivisions bounded by Warden Avenue, Birchmount Rd, Steeles Avenue and McNicoll Avenue with all assets constructed to standard.

Description:

- There have been six unplanned outages in this area over the past two years. These outages have contributed to almost one million total customer minutes out. The total number of customer interruptions during these six outages was approximately 4000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with switches and fuses within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized

to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E07355

Business Case Summary

Project Title: Underground rehabilitation at Tange Briarway and Leslie Street

Estimated Cost: $684,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 51M6
- To rebuild the town home complex bounded by Finch Avenue, Sheppard Avenue, Leslie Avenue and Bayview Avenue with all assets constructed to standard.

Description:

- There have been five unplanned outages in this area over the past two years. These outages have contributed to approximately one half million total customer minutes out. The total number of customer interruptions has been unusually high contributing to about thirteen thousand.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. The direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E07358

Business Case Summary

Project Title: Underground rehabilitation at Sheppard Avenue, Quantrell Trail area

Estimated Cost: $6,010,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing direct buried primary cable
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M3
- To rebuild the town home complex bounded by Sheppard Avenue, Quantrell Trail, Brenyon Way and Neilson Rd. with all assets constructed to standard.

Description:

- There have been six unplanned outages in this area over the past two years. These outages have contributed to approximately one hundred and fifty thousand total customer minutes out. The total number of customer interruptions has been unusually high contributing to almost ten thousand.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with fuses and switches within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- This project will address reliability concerns of feeder NT47M3 which is on the THESL worst performing feeder list.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08300

Business Case Summary

Project Title: E08300 Port Royal NT63M4 UG Repl.SE.part, Electrical

Estimated Cost: $784,196

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT63M4.
- To rebuild to modern standards the subdivisions on Port Royal South East – the distribution system on Bretton Ct, MoorehouseDrive, McCool Ct, Gageview Ct, James Park Sq, Campania Cr and south east side of Port Royal Tr.

Description:

- There have been four unplanned outages in this area over the past two years (2002 to 2003). These outages have been unusually long duration outages contributing to almost 25,830 customer minutes out. The total number of customer interruptions during these four outages was 3,760.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and

continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with switches and fuses within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions, ie avoided potential second contingency scenarios

PROJECT #: E08118

Business Case Summary

Project Title: Underground rehabilitation at Pinetree Subdivision

Estimated Cost: $4,057,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve reliability of feeder NT47M1

Description:

- Rebuild the remaining portion of Pinetree subdivision (Streets included in the area are McLevin Avenue (part), Malvern St and all town homes there, RobinstoneDrive, Lenthal Avenue, Verne Cr, Ormerod St, Applemore Rd, Sunburst Sq, Greenhedges Ct, part of Mammoth Hall Tr)
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced by fuses and switches within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08119

Business Case Summary

Project Title: Underground Rehabilitation at Morningside, Sewells Area

Estimated Cost: $2,726,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M3

Description:

- Rebuild the NT47M3 feeder lateral as part of the main trunk in sections of Sewells Rd. between Neilson Rd. and Morningside Avenue & Morningside Avenue between Morningview Tl and Old Finch Rd & McLevin Avenue between Neilson Road and Morningside Avenue
- There have been seven unplanned outages in this area over the past two years. These outages have been unusually long duration outages contributing to just over one million total customer minutes out. The total number of customer interruptions has also been unusually high during these seven outages at almost 27,000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and

continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with fuses and switches within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- This project will address reliability concerns of feeder NT47M3 which is on the THESL worst performing feeder list.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act,

and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08124

Business Case Summary

Project Title: Underground Rehabilitation of feeder NY51M25: Shawnee and Nootka

Estimated Cost: $1,760,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve reliability of feeder 51M25

Description:

- Rebuild feeder NY51M25 in the area of Shawnee Cl. and Nootka Cres.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during

future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08141

Business Case Summary

Project Title: Underground Rehabilitation SCNT63M6 at Hartleywood area

Estimated Cost: $1,766,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve reliability of feeder NT63M6

- Replace a portion of primary cable in the area bounded by Huntingwood Drive, Brimley Rd., McCowan Rd. and Finch Avenue referred to as Chartwell Subdivision Phase II Stage IV

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with fuses and switches within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

PROJECT #: E08161

Business Case Summary

Project Title: Feeder Conversion SCYHF1 & SCYHF3: Military Tr & Morningside Avenue

Estimated Cost: $886,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the future decommissioning of an old municipal station via voltage conversion

Description:

- Use feeder SCNT47M8 and the existing 27.6kV primary in the area to convert the remaining 4kV loads on feeders SCYHF1 and SCYHF3 in the area bounded by Morningside Avenue and Brook Rd & HOROW and Ellesmere Rd.
- There have been four unplanned outages in this area over the past two years.
- Based upon station loading data, the municipal substation Military Trail – Morningside M.S. YH is under utilized. In order to reduce operating expenses associated with this station, it will be decommissioned.
- In the vicinity of this area, there are two areas of 13.8kV distribution system. There is a long span of 13.8 kV overhead line from McCowan road to Morningside Avenue along Sheppard Avenue with this station connecting the two areas. This long span of overhead line contributes to increased interruptions and additional line losses. It is intended that this long line will be eliminated.
- Lines presently used strictly for back-up purposes will be removed within the scope of this project
- This voltage conversion has the added benefit of reducing system losses and will ultimately aid in the goal of reducing power consumption in the province of

Ontario.

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result large additional expenditures on maintenance to old plant with rare equipment that is difficult to replace. This will have negative impact on customers and system reliability.

Results:

- Improved feeder reliability, reducing both outage duration and frequency.
- Assets at their end of service life will be replaced.

UNDERGROUND REHAB

Table 2: Underground Rehab Projects

Project Number	Project Title	Estimated Cost ($)
DC_E08066	Permanent Cut Repair Restoration – East	1,200,000
DC_E08070	System Enhancement: Underground Cable Rehabilitation - East	1,454,600
DC_W08086	System Enhancement: Underground Cable Rehabilitation – West	1,455,000
DC_W08091	Permanent City Cut Restoration – West	800,000
E08037	Overhead to underground rehabilitation at Leaside Bridge	519,000
E08061	Underground rehabilitation NYSS68F2 on Leslie St: Sheppard to Finch	615,000
E08069	Design for 2009 Projects – Distribution Projects East	1,200,800
N08214	Underground Rehabilitation: Leaking Cable Repair on Charles TS feeders	805,000
W07324	Underground rehabilitation at Keele Street, York Boulevard Area	570,000
W07327	Underground rehabilitation and conversion: Jamestown Crescent area	700,000
W07366	Underground conversion 4 kV to 27.6 kV: Forest Hill area	2,343,000
W08029	Underground Conversion – Civil (Phase 1) St. Clair: Caledonia to Gunns	2,253,000
W08030	Rebuild Yorkdale Shopping Mall distribution	2,250,000
W08087	Design for 2009 Projects – Distribution Projects West	1,599,000
W08109	Underground Conversion - Electrical on St. Clair: Oakwood to Westmount	1,117,000
W08139	Feeder Enhancement: Wiltshire	655,000
W08192	Civil build: preparations for load transfer Windsor TS to Portland TS.	2,000,000
W08209	Underground Conversion – Electrical (Ph. 2) St. Clair: Caledonia to Gunns	1,352,000

Project Number	Project Title	Estimated Cost ($)
W08213	Civil Rebuild Dupont: Bathurst to Kendal	553,000
W08217	Underground Rehabilitation, Civil Construction on Bay Street	1,343,000
W08243	Civil Enhancement on Lake Shore: Windermere to Parkside	797,000
W08244	Underground Rehabilitation: Civil Construction on Bloor Street	1,350,000
Overall Cost		**25,131,400**

PROJECT #: DC_E08066

Business Case Summary

Project Title: Permanent Cut Repair Restoration - East

Estimated Cost: $1,200,000

Portfolio: Underground Rehabilitation

Objective:

To compensate the City of Toronto for costs they incur to permanently repair city infrastructure such as roads, sidewalks and boulevards in the east portion of the city.

Description:

In the process of undertaking (usually) underground construction work, THESL is required to break into existing City of Toronto infrastructure such as roads, sidewalks, and boulevards. Once the THESL work is completed, the City of Toronto's contractors repair/restore the damaged infrastructure. All efforts are made between THESL, the City of Toronto, and a number of other utilities to avoid conflict of schedules. Furthermore, co-ordination is made in order to facilitate efficiencies such as the agreement between utilities of joint-use trenches.

Timely cut-repairs are required right away in order to address the following issues:

- Customer complaints due to unsightly landscape
- Potential public safety hazards
- Exposure to further financial risk

Deferral of this project would unduly prolong the presence of fenced construction areas. This would impede the flow of pedestrian and vehicular traffic in the area concerned. Deferral will also lead to non-compliance with established City of Toronto regulations

Results:

- Compliance with City of Toronto regulations
- Improved public safety
- Mitigation of financial risk

IP REFERENCE #: DC_E08070

Business Case Summary

Project Title: System Enhancement: Underground Cable Rehabilitation - East

Estimated Cost: $1,454,600

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of unplanned capital investments related to underground assets in the east portion of the city. For the most part, engineering and design is required
- To resolve unplanned underground infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to underground assets.
- To address defective underground plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as cable chambers, vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to

capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W08086

Business Case Summary

Project Title: System Enhancement: Underground Cable Rehabilitation – West

Estimated Cost: $1,455,000

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of unplanned capital investments related to underground assets in the west portion of the city. For the most part, engineering and design is required
- To resolve unplanned underground infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to underground assets.
- To address defective underground plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as cable chambers, vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to

capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W08091

Business Case Summary

Project Title: Permanent City Cut Restoration - West

Estimated Cost: $800,000

Portfolio: Underground Rehabilitation

Objective:

To compensate the City of Toronto for costs they incur to permanently repair city infrastructure such as roads, sidewalks and boulevards in the west portion of the city.

Description:

In the process of undertaking (usually) underground construction work, THESL is required to break into existing City of Toronto infrastructure such as roads, sidewalks, and boulevards. Once the THESL work is completed, the City of Toronto's contractors repair/restore the damaged infrastructure. All efforts are made between THESL, the City of Toronto, and a number of other utilities to avoid conflict of schedules. Furthermore, co-ordination is made in order to facilitate efficiencies such as the agreement between utilities of joint-use trenches.

Timely cut-repairs is required right away in order to address the following issues:

- Customer complaints due to unsightly landscape
- Potential public safety hazards
- Exposure to further financial risk

Deferral of this project would unduly prolong the presence of fenced construction areas. This would impede the flow of pedestrian and vehicular traffic in the area concerned. Deferral will also lead to non-compliance with established City of Toronto regulations

Results:

- Compliance with City of Toronto regulations
- Improved public safety
- Mitigation of financial risk

PROJECT #: E08037

Business Case Summary

Project Title: Overhead to underground rehabilitation at Leaside Bridge

Estimated Cost: $519,000

Portfolio: Underground Rehabilitation

Objective:

- To convert feeder 34M1 plant from overhead to underground.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address low probability, high impact failures of overhead plants which will result in mitigating potential lengthy restoration.
- To enhance THESL accessibility concerns for high voltage lines.

Description:

- This is one of six project phases required to complete the efforts to transfer the overhead lines crossing the Don Valley to the new conduit along Leaside Bridge.
- Most of the faults/failures in this area are caused by tree contacts (breaking of branches, falling trees, brushing of branches), squirrels, adverse weather, lightning, tracking, and insulator failure
- Although there has not been any work refusals within this area to date, the field staff have raised the issue regarding accessibility to the route that passes along slopes on the valley filled with trees. During winter, it is very difficult to even patrol the route in order to just determine the cause of a fault/outage. At times, the broken tree branch requires removal before restoration of supply is achieved. Generally, the restoration time is higher than normal in this area.
- Create a physical separation of the main 27.6kV underground trunk lines that supply the area bounded by the Don Valley Parkway, O'Connor Drive, Woodbine

and Danforth Avenue.

- Rectify reliability concerns regarding the overhead crossing of the feeders' main trunk lines across and along the Don Valley.
- Address low probability, high impact potential failure concerns for the area.
- Build infrastructure to address other primary feeders (34M2, 34M3 and 34M4) crossing the Don River for future underground enhancement.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in further stress to the operation and maintenance of overhead plants in the area and creates risk of potential loss of supply to customers. Continued reduction in system reliability will also be experienced, resulting in further negative customer impacts.

Results:

- Maintain feeder reliability.
- Reduce potential lengthy restoration.
- Improve safety and accessibility to overhead plants.
- Replace assets at their end of service life.

PROJECT #: E08061

Business Case Summary

Project Title: Underground rehabilitation NYSS68F2 on Leslie St: Sheppard to Finch

Estimated Cost: $615,000

Portfolio: Underground Rehabilitation

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve reliability of NYSS68F2

Description:

- There have been three unplanned outages in this area over the past two years. The total number of customer interruptions during these three outages was approximately 2000.
- Replace underground portion of the main trunk of feeder SS68-F2, along Leslie Street from pole # 1288 Sheppard Avenue (S1309) to pole #4911 Finch Avenue E. (S1310) as per latest THESL Standards and Practice.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and a recent asset condition inspection of the area has revealed a necessity for replacement.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards

which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction in system reliability, resulting in further negative customer impacts.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Assets at their end of service life will be replaced.

PROJECT #: E08069

Business Case Summary

Project Title: Design for 2009 Projects – Distribution Projects East

Estimated Cost: $1,200,800

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of designing projects for construction in 2009. These designs encompass distribution projects located in the east portion of the city.

Description:

- The designer will use the issued project documentation for work coordinated between East Construction and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Designing include:

- Create drawings and specifications
- Field work
- Prepare bill of materials and order material and equipment.
- Prepare detailed estimate
- Arrange for work permits pursuant to provincial and federal legislation
- Send projects out for construction.

- Administer civil contracts

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns
- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Optimal resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: N08214

Business Case Summary

Project Title: Underground Rehabilitation: Leaking Cable Repair on Charles TS feeders.

Estimated Cost: $805,000

Portfolio: Underground Rehabilitation

Objective:

- To mitigate high restoration costs
- To mitigate overload conditions of nearby cables
- To mitigate very long outages

Description:

- Replace PILC cables in the area bounded by Parliament, Carlton, Bloor East and Bay/Yonge streets from Charles TS
- PILC cable leaks have been an ongoing concern with respect to reliability over the last decade. Consequences of leaking cables include a higher probability of cable failure, decreased system reliability, as well as adverse environmental concerns.
- Failure of leaking cables while in-service results in additional costs, and can disrupt other scheduled work. THESL deficiency database indicates that there are still 918 unattended leaks, (in cables, joints and potheads) including 159 locations with multiple leaks.
- This phase will focus on the east portion of the city and improve reliability to feeders associated with Charles TS
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act,

and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in more emergency and reactive maintenance with increased costs to these areas. Continued reductions in system reliability, resulting in negative customer impacts also pose an issue. Further safety and environmental hazards are also left unattended

Results:

- Improved Feeder reliability, reducing both outage duration and frequency.
- Elimination of potential public hazards.
- Elimination of potential emergency and reactive maintenance costs.

PROJECT #: W07324

Business Case Summary

Project Title: Underground rehabilitation at Keele Street, York Boulevard Area

Estimated Cost: $570,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of the Finch 55M24 and address the end-of-life condition of direct buried cable and cables in ducts.

Description:

- A portion of the Finch 55M24 feeder services an area bounded by Keele Street, York Boulevard Sentinel Road and Four Winds Drive. There are three sections of underground cables of Finch T.S. 55M24 that have recently and repeatedly faulted.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree

retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased

- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W07327

Business Case Summary

Project Title: Underground rehabilitation and conversion: Jamestown Crescent area

Estimated Cost: $700,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Jamestown Crescent area.

Description:

- Convert the old distribution system to 27.6kV in the Jamestown Crescent area of Albion municipal station F-4.
- The distribution system was built in the sixties as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e.,, avoided potential second contingency scenarios

PROJECT #: W07366

Business Case Summary

Project Title: Underground conversion 4 kV to 27.6 kV: Forest Hill area

Estimated Cost: $2,343,000

Portfolio: Underground Rehabilitation

Objective:

- To relocate primary and secondary rear fed distribution to front lot underground
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address age and difficulty for accessing THESL-owned equipment

Description:

- To address deteriorating rear lot distribution in the Forest Hill area bounded by Bathurst Street, Briar Hill, Allen Express Way and Ridelle Avenue
- To convert the 4kV distribution in the rear to 27.6kV underground distribution in the front using feeder 35M6 on Bathurst Street
- This project has been selected based on criteria used to prioritize rear lot plants
- The criteria used are:
    - Plant age
    - Number of customers
    - Primary voltage
    - Adjacent area's primary voltage
    - Adjacent area's construction type
    - Tree density
    - Customer satisfaction

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in continued repeat service calls for localized outages with associated Customer service degradation and eventual widespread outages and escalating operating costs. The existing 4 kV primary distribution in this area is beyond its service life and the rear lot distribution in this mature area adds to the ongoing maintenance costs.

Alternatives:

- A number of alternatives were analyzed and compared. The cost and safety feasible alternative was this changeover permitting long run improvements in the way electrical services can be provided and maintained in this area.

Results:

- Reduced maintenance costs over the immediate term
- Improvements in servicing by THESL field crews
- Improve reliability
- Safer distribution system
- Easy accessibility for crews and less disruption to customers

PROJECT #: W08029

Business Case Summary

Project Title: Underground Conversion – Civil (Phase 1) St. Clair: Caledonia to Gunns

Estimated Cost: $2,253,000

Portfolio: Underground Rehabilitation

Objective:

- To build a new civil infrastructure on St. Clair Avenue West
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages

Description:

- This project covers the installation of new civil infrastructure including cable chambers, vaults and duct banks on the north and south sides of St. Clair Avenue West for future conversion of overhead distribution system to underground system.
- Follow cost sharing arrangement between THESL and the City according to *Public Services Works on Highway Act*. Fifty per cent of the cost will be covered by the City of Toronto. THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Alternatives:

- TTC is upgrading their rail system along St. Clair Avenue West. THESL is required to underground its existing overhead electrical distribution plant on St. Clair from Yonge Street to Gunns Road (in the west)
- The City of Toronto has agreed to provide fair contribution for this project

Results:

- Improve streetscape.
- Improve reliability reducing outage duration and frequency
- Replace end of life assets

PROJECT #: W08030

Business Case Summary

Project Title: Rebuild Yorkdale Shopping Mall distribution

Estimated Cost: $2,250,000

Portfolio: Underground Rehabilitation

Objective:

- To improve the reliability of distribution within Yorkdale Shopping Mall.
- To address the end-of-life condition of equipment.

Description:

- There have been safety and reliability concerns at the Yorkdale Shopping Centre regarding the underground feeder cables, the automatic transfer switches ("ATSs") and ten of the fourteen transformers. This equipment has already reached its end of service life and has failed in the past.
- To improve reliability, replace ten of the aging transformers and the feeder cables of feeders 85M9 and 35M7 within the shopping centre. In addition, the existing ATSs from Vault #2 to Vault #8 will be replaced with comparable ATS units.
- New duct structure and modifications to the existing vaults is needed to house the new cables, the ATS, and the new transformers. The customer will provide the civil structure at their expense. This cost will be discounted from overall project cost.
- Currently the Yorkdale Mall is supplied with two feeders throughout the eight vaults as normal and standby, with ATS and two transformers feeding the secondary bus.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards

which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, no abatement of safety hazards, and further customer inconveniences.

Alternatives:

- Single feeder through eight vaults, with normally open point in the middle with manual transfer switch, using two transformers
- Single feeder through eight vaults, with normally open point in the middle with auto transfer switch, using two transformers
- Single feeder through eight vaults, with normally open point in the middle with manual transfer switch, using single transformers
- Single feeder through eight vaults, with normally open point in the middle with auto transfer switch, using single transformers
- Based on the reliability as proposed by the consultants of the customers, it was decided to maintain the existing distribution system within the customer's property and replace the aging, deteriorating, and constantly failing equipment and transformers with future expected load growth in the area.

Results:

- Feeder and equipment reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Virtual elimination of maintenance costs over the immediate term.
- Elimination of electrical hazards to both Hydro employees and the public.

- Significant improvement to electrical reliability for this area.

PROJECT #: W08087

Business Case Summary

Project Title: Design for 2009 Projects – Distribution Projects West

Estimated Cost: $1,599,000

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of designing projects for construction in 2009. These designs encompass distribution projects located in the west portion of the city.

Description:

- The designer will use the issued project documentation for work coordinated between West Construction and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Designing include:

- Create drawings and specifications
- Field work
- Prepare bill of materials and order material and equipment.
- Prepare detailed estimate
- Arrange for work permits pursuant to provincial and federal legislation
- Send projects out for construction.

- Administer civil contracts

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns
- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Optimal resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: W08109

Business Case Summary

Project Title: Underground Conversion - Electrical on St. Clair: Oakwood to Westmount

Estimated Cost: $1,117,000

Portfolio: Underground Rehabilitation

Objective:

- To rehabilitate the electrical distribution system on St Clair Avenue West from Oakwood to Westmount.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages

Description:

- Building on the new civil infrastructure installed on St. Clair Avenue West. This project covers the installation of the underground electrical distribution.
- Install and extend two new 13.8 kV feeders from Dufferin Transformer Station to convert the overhead 4 kV loads between Oakwood and Westmount Avenue on St. Clair Avenue.
- Convert all 4 kV overhead supply to 13.8 kV underground plant
- Follow cost sharing arrangement between THESL and the City according to *Public Services Works on Highway Act*, 50 per cent of the cost will be covered by the City of Toronto
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Alternatives:

- Maintain 4 kV system and reroute plant
- Replace assets with an overhead 13.8 kV system
- Convert the overhead plant to underground, including newly constructed civil infrastructure and electrical distribution assets.

Results:

- Improve streetscape
- Improve reliability reducing outage duration and frequency Primary assets at their end of service life will be replaced.
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood

PROJECT #: W08139

Business Case Summary

Project Title: Feeder Enhancement: Wiltshire

Estimated Cost: $655,000

Portfolio: Underground Rehabilitation

Objective:

- To create some spare positions on A5-6 Wiltshire bus to accommodate future conversion of deteriorating 4 kV neighbouring stations such as Junction MS, Runnymede MS, Keele St. Clair MS and Wiltshire MS.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages

Description:

- To replace obsolete feeders south of Wiltshire Station with ones conforming to current Hydro standards.
- To create spare feeder positions at Wiltshire Station for future use and permit much needed conversion of the preceding 4 MS stations
- With the completion of the A5-6 bus now capable for carrying 4-Wire feeders. The entire distribution out of this station is being reviewed in order to create some spare position on A5-6 bus.
- This review is needed to address future conversion of Junction MS, Runnymede MS, Keele St. Clair MS and Wiltshire MS 4 kV Stations.
- In analysing the feeders south of Wiltshire Station it is feasible to upgrade some feeders that are covered in this project from the old 250 and 350kcmil belted to 500kcmil. This will also allow the elimination of feeder leakers, consolidation of loads, reduce congestions in the cable chamber and create spare feeder position at the station for future use.

- There are nine 13.8 kV radial feeders in question from A1-2W, A3-4W and A5-6W. The rearrangement and transfer to A1-2W bus will result in reducing the need for these nine feeders. These feeders are A-35-50-62-63-64-67-68-69-70W, carry a combine load of 20.7MVA of which half of this load already exists on A1-2W and thus the remaining 10.9MVA is to be transferred from the other two busses. The end result would be nine feeders reduced to five (A-64-67-68-69-70-W) and the remaining four feeders on the A5-6bus to remain spare for future conversion use.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would lead to accelerating reactive maintenance costs and no remediation of potential hazards result. Customer inconveniences could be expected to continue.

Results:

- Reduced maintenance costs over the short & medium terms
- Improvements in internal safety
- Elimination of fire, electrical and environmental hazards for “leakers”
- Reduction of hazards for the public
- Improved system reliability for the affected community
- Expansion of system capacity
- Improvements in cable handling by Hydro field crews

PROJECT #: W08192

Business Case Summary

Project Title: Civil build: preparations for load transfer Windsor TS to Portland TS.

Estimated Cost: $2,000,000

Portfolio: Underground Rehabilitation

Objective:

- To build civil infrastructure in order to prepare for the installation of a switchgear at Portland Station and the subsequent load transfer from Windsor Station.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages

Description:

- Build civil infrastructure consisting of cable chambers, and duct banks for the above objective
- Windsor Station – 13. 8 kV, in downtown Toronto has an installed capacity of 300 MVA with peak demand of 267 MVA.
- Real estate at Windsor station is limited for capacity upgrade.
- Windsor Station feeds a large concentration of key customers in downtown Toronto with little space for diversity of loads should the switchgear fail. The switchgears at Windsor Station is fast approaching it end of life. In the interim a 13.8 kV switchgear will be installed at a nearby building to phase in the replacement of switchgear at Windsor station.
- It is proposed to install new 13.8 kV switchgear at Portland Station and feed the power from Strachan Station, which has spare capacity.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards

which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, and further inconveniences for a large concentration of key customers in downtown Toronto.

Alternatives:

- Various alternatives have been studied, including coordinating with HONI to build a new 13.8 kV station in the downtown Toronto area. The best alternative has been to install new 13.8 kV switchgear at Portland station, energize from the Strachan Station and transfer some Windsor Station loads to this switchgear for diversity. This will also allow future expansion and replacement of some of the old switchgear at Windsor Station.

Results:

- Improve reliability to concentration of key customers in downtown Toronto.
- Diversify loads from the near capacity Windsor Station.
- Provide flexibility in future replacement of aging switchgear at Windsor Station.

PROJECT #: W08209

Business Case Summary

Project Title: Underground Conversion – Electrical (Ph. 2) St. Clair: Caledonia to Gunns

Estimated Cost: $1,352,000

Portfolio: Underground Rehabilitation

Objective:

- To rehabilitate the electrical distribution system on St Clair Avenue West from Caledonia to Gunns
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages

Description:

- Building on the new civil infrastructure installed on St Clair Avenue West. This project covers the installation of the underground electrical distribution.
- Extend two existing 13.8 kV feeders from Wiltshire Transformer Station to convert the overhead 4 kV loads between Caledonia and Gunns Rd on St. Clair Avenue. In doing so, system line losses can be reduced at the higher voltage.
- Follow cost sharing arrangement between THESL and the City according to *Public Services Works on Highway Act*, 50 per cent of the cost will be covered by the City of Toronto.
- Consideration will be given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Alternatives:

- Maintain 4kV system and reroute plant
- Replace assets with an overhead 13.8 kV system
- Convert the overhead plant to underground, including newly constructed civil infrastructure and electrical distribution assets.

Results:

- Improve streetscape
- Improve reliability reducing outage duration and frequency as a result of an underground system
- Primary assets at their end of service life will be replaced.
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Reduction of system line losses

PROJECT #: W08213

Business Case Summary

Project Title: Civil Rebuild Dupont: Bathurst to Kendal

Estimated Cost: $553,000

Portfolio: Underground Rehabilitation

Objective:

- To replace unsuitable underground cable chambers
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages

Description:

- Inspection of chambers within project area has revealed that many chambers require structural repairs.
- Most chambers were constructed with brick and have irregular, non-standard shape, poor working space, and deteriorated roofs.
- Rebuild deteriorating UG infrastructure along Dupont between Bathurst and Kendal.

Not proceeding with this investment will result in further deterioration of cable chamber conditions, threatening the safety of operating Hydro crews, as well as the housed infrastructure.

Results:

- Safe environments for THESL personnel
- Improved reliability, reducing outage duration and frequency
- By alleviating congestion, personnel safety will be improved.

PROJECT #: W08217

Business Case Summary

Project Title: Underground Rehabilitation, Civil Construction on Bay Street

Estimated Cost: $1,343,000

Portfolio: Underground Rehabilitation

Objective:

- To rebuild the old and deteriorating underground civil and electrical plant on Bay Street, between Dundas Street and Queen Street.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the egress congestion issue at Terauley Station.

Description:

- The City of Toronto is doing major road construction on Bay Street between Dundas Street West and Queen Street West in the third quarter of 2007. Then a moratorium will be placed in this area for the next five years.
- Rebuild the old and deteriorating underground civil and electrical infrastructure on Bay Street, between Dundas Street and Queen Street.
- Install additional civil infrastructure for egress from Terauley Station.
- This project includes rebuilding of approximately eight cable chambers and installing cables in structures in the area according to our current standards.
- Remove some dead end and unused cables; replace other very old deteriorating cables with new ones as per our standards.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in accelerating deterioration of our infrastructure and the likelihood of considerable interruptions to our major commercial and institutional customers in the downtown business core.

Results:

- The old and deteriorating underground electrical system on Bay Street between Dundas Street West and Queen Street West will be rebuilt.
- Substantial reduction in upfront reactive and emergency maintenance costs over the short and medium terms.
- Improvements in internal safety.
- Elimination of fire and electrical hazards.
- Reduction in electrical hazards for the public.
- Improvements in system reliability.
- Sharp reduction in collateral damages to other utilities' and the City's infrastructure from Hydro infrastructure defects.

PROJECT #: W08243

Business Case Summary

Project Title: Civil Enhancement on Lake Shore: Windermere to Parkside

Estimated Cost: $797,000

Portfolio: Underground Rehabilitation

Objective:

- Install a new civil infrastructure along Lake Shore Boulevard West from Windermere Avenue to Parkside Drive.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To eliminate the existing infrastructure on the Gardener Expressway.

Description:

- Extending our infrastructure from a cable chamber east of Windermere Avenue along Lake Shore Boulevard West to Parkside Drive to eliminate dangers and hazards that can occur on the Gardener Expressway to our work crews.
- Because of continuous high speed traffic on Gardener Expressway, these cable chambers on the Expressway become inaccessible all the time
- Moreover costly special equipment is required to access and install cables.
- This project covers the installation of new civil infrastructure including cable chambers, vaults and duct banks.
- The electrical portion of this project will be done the following year.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Alternatives:

- Maintaining the existing infrastructure on the Gardiner Expressway is costly and at times unsafe for THESL crews to work.

Results:

- Reduce maintenance cost.
- Improve safety.
- Replace end of life assets.

IP REFERENCE #: W08244

Business Case Summary

Project Title: Underground Rehabilitation: Civil Construction on Bloor Street

Estimated Cost: $1,350,000

Portfolio: Underground Rehabilitation

Objective:

- To improve the condition of civil infrastructure on Bloor Street between Church Street. and University Avenue as per the City's road and sidewalk reconstruction program.
- To coordinate with city projects to restore the underground distribution system and rebuild cable chambers along Bloor Street between Avenue Rd and Church Street

Description:

- To coordinate with city projects, this investment aims to restore underground distribution system through the construction of approximately 580.0m of underground conduit and the rebuilding of eight cable chambers along Bloor Street between Avenue Rd and Church Street
- A review of existing underground infrastructure has revealed that capacity for future growth through this area is very limited due to lack of spare duct capacity.
- Piece out, replace or maintain existing primary cabling
- Coordinate work with City representatives and other utilities such as Traffic and Street Lighting.
- Follow cost sharing arrangement between THESL and the City according to Public Services Works on Highway Act. $460,000 of the cost will be covered by the City of Toronto.

- The City intends to "Beautify" Bloor Street between Church and University Avenue. The project will include road and sidewalk reconstruction including significant curb modifications.
- After city's re-construction, a moratorium will be placed by the city in this area for the next five years
- A review of existing underground infrastructure has revealed that capacity for future growth through this area is very limited due to lack of spare duct capacity with most of the available ducts being square tile.
- The proposed realignment of the curb being proposed by the City significantly impacts three of our existing vaults and the mutual resolution to these conflicts will have to be resolved as part of this project.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

Results:

- Customer satisfaction increased
- Reduction to stressed assets
- By alleviating congestion, personnel safety will be improved.

OVERHEAD

Table 3: Overhead Projects

Project Number	Project Title	Estimated Cost ($)
DC_E08074	System Enhancement: Overhead Rehabilitation – East	518,000
DC_W08090	System Enhancement: Overhead Rehabilitation - West	518,000
E08033	Overhead conversion at area bounded by Jones, Harcourt Area	1,574,000
E08215	Overhead rehabilitation – installation of new 27.6 kV SCADA switches	1,827,000
E08229	Overhead conversion in O'Connor Drive and Dohme Avenue area	793,602
E08232	Equipment Nomenclature Enhancement – East	3,800,000
E08245	Overhead conversion in Woodycrest, Eaton and Pape area	802,000
W07278	Overhead rehabilitation – installation of new 27.6kV SCADA switches	1,827,000
W08131	Feeder extension 85M5: Bathurst TS	766,000
W08191	Voltage Conversion 4kV to 27.6kV on Bathurst St: Avenal to Tichester	650,000
Overall Cost		**13,075,602**

IP REFERENCE #: DC_E08074

Business Case Summary

Project Title: System Enhancement: Overhead Rehabilitation - East

Estimated Cost: $518,000

Portfolio: Overhead

Objective:

- To cover the cost of unplanned capital investments related to overhead assets in the east portion of the city. For the most part, engineering and design is required
- To resolve unplanned overhead infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to overhead assets.
- To address defective overhead plant that poses unforeseen significant risk to system reliability.

Description:

- This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

- Equipment replacement is required in order to address the following issues:
  - Customer complaints due to extended outages
  - Potential poor system reliability performance due to increased stress on nearby assets
  - Potential public safety concerns
  - Potential environmental concerns
  - Potential THESL personnel safety concerns
  - Exposure to further financial risk caused by damage to other associated assets
  - Maintain operating conditions; i.e., avoid second contingency conditions
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

- Reduction of system line losses

IP REFERENCE #: DC_W08090

Business Case Summary

Project Title: System Enhancement: Overhead Rehabilitation - West

Estimated Cost: $518,000

Portfolio: Overhead

Objective:

- To cover the cost of unplanned capital investments related to overhead assets in the west portion of the city. For the most part, engineering and design is required
- To resolve unplanned overhead infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to overhead assets.
- To address defective overhead plant that poses unforeseen significant risk to system reliability.

Description:

- This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

- Equipment replacement is required in order to address the following issues:
  - Customer complaints due to extended outages
  - Potential poor system reliability performance due to increased stress on nearby assets
  - Potential public safety concerns
  - Potential environmental concerns
  - Potential THESL personnel safety concerns
  - Exposure to further financial risk caused by damage to other associated assets
  - Maintain operating conditions; i.e., avoid second contingency conditions
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: E08033

Business Case Summary

Project Title: Overhead conversion at area bounded by Jones, Harcourt Area

Estimated Cost: $1,574,000

Portfolio: Overhead

Objective:

- To increase capacity to accommodate future load growth.

Description:

- The electrical distribution in the area bounded by Carlaw, Danforth, Greenwood, and CN railway is planned for voltage conversion to address end of service life assets and an ongoing investment plan to decommission old, unreliable stations
- This voltage conversion has the added benefit of reducing system losses and will ultimately aid in the goal of reducing power consumption in the province of Ontario.
- This is one of four phases in the area. Areas fed by feeders B14E, B8HW and B6HW will be beneficially affected with increased reliability. Also, this will add operational flexibility to the grid
- The condition of the distribution plant along with obsolete non-standard equipment, and old poles plays an integral part in the overall reliability of an overhead distribution system. As evidenced in the ACA, there are almost 1100 poles requiring replacement over the next three years. Also, as evidenced by the ACA, almost 350 pole-top transformer units are required to be replaced over the next three years.
- Within the area covered by this project and within the nearby vicinity, there are only two overhead feeders. Both of these have reached 100% capacity
- This project will rebuild the area bounded by Jones, Harcourt, Pape, and Bain

Avenue by conversion to 13.8kV, installing new poles, overhead lines and transformers.

- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in further stress to the operation and maintenance of overhead plants in the area and creates risk of potential loss of supply to customers. Continued reduction in system reliability will also be experienced, resulting in further negative customer impacts.

Alternatives:

- Install 4kV underground cable and associated underground equipment. This option is more expensive and does not offer any distribution efficiency benefit.
- Replace existing overhead with new poles and conductors of the same voltage. This will not address the capacity issues.
- Deferral is not an option due to capacity limitations.

Results:

- There will be safety and feeder reliability improvements, positively affecting Hydro personnel and customers.
- Primary assets at their end of service life will be replaced.

PROJECT #: E08215

Business Case Summary

Project Title: Overhead rehabilitation – installation of new 27.6kV SCADA switches

Estimated Cost: $1,827,000

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI.
- To improve substandard communication for existing remote switches.

Description:

- Convert 23 switch locations of old existing Bell communication line using the new wireless communication system and new SCADA operated switches in Scarborough area.
- Existing switches are aging and have non-standard communication components
- Existing switches have old and non-reliable battery and charger
- Existing failing radio system that has potential to disable remaining radio communication
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- Spare parts for existing equipment difficult to attain
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location should is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- This project will improve reliability to all feeders associated with Scarborough TS located in the east portion of the city
- THESL will conduct this work in accordance with the OHSA and associated

regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued rental payment to Bell and reduction in reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- Eliminate rental cost of the Bell leased lines.
- End of Life replacement for old assets within the remote switch class
- Immediately after the first few switches are replaced, the spare parts issue is considerably improved
- The new RTUs are “Feeder Automation” ready (should THESL decide to pursue this initiative)

PROJECT#: E08229

Business Case Summary

Project Title: E08229 Overhead conversion in O'Connor Drive and Dohme Avenue area

Estimated Cost: $793,602

Portfolio: Overhead

Objective:

- To enhance system reliability and minimize costs compared to maintaining existing old and non-standard 4 KV plants.
- To improve the operational flexibility of the grid

Description:

- To convert to a higher voltage the area (pertinent to feeders out of MS station H and J) around O'Connor Drive and Dohme Ave using 27.6kV feeders NY53M3 and EY53M7
- The condition of the distribution plant along with obsolete non-standard equipment, and old poles plays an integral part in the overall reliability of an overhead distribution system. As evidenced in the ACA, there are almost 1100 poles requiring replacement over the next three years. Also, for pole-top transformers, almost 350 units are required to be replaced over the next three years.
- Maintenance of the existing 4kV system in this area is costly due to the condition of the plant and unavailability of spare parts
- The assets in this area are old and less reliable, and in many cases, do not meet our current standards.
- This voltage conversion has the added benefit of reducing system losses and will ultimately aid in the goal of reducing power consumption in the province of Ontario

- This project will improve reliability and operational flexibility to areas currently supplied by feeders F1, F2, F3, and F4 supplied by Highlevel station and feeders F3 and F4 from 'J' station
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration
- Reduction of system line losses

IP REFERENCE #: E08232

Business Case Summary

Project Title: Equipment Nomenclature Enhancement – East

Estimated Cost: $3,800,000

Portfolio: Overhead

Objective:

- To re-label all the operable distribution devices across the distribution system according to a new consistent nomenclature standard.

Description:

- There are six legacy location identification approaches across the distribution system, some of which vary immensely from the others. This creates potential confusion to crews that may not be familiar with these standards and could pose operational hazards.
- In order to eliminate the potential hazards of improper operation, there is a need to harmonize the nomenclature. All devices need to be relabelled according to the new nomenclature standard.
- The new nomenclature also supports the new DMS System in Operation.
- In certain locations, THESL personnel are required to isolate the asset to be labelled. This requires a set of switching procedures to be followed according to THESL's work protect code
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

Deferral or failure to address these deficiencies could lead to inappropriate operation of equipment in the field.

Results:

- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios
- Mitigation of hazards to THESL personnel and public

IP REFERENCE #: E08245

Business Case Summary

Project Title: Overhead conversion in Woodycrest, Eaton and Pape area

Estimated Cost: $802,000

Portfolio: Overhead

Objective:

- To improve system reliability and address aging assets associated with feeder B6HW

Description:

- This project aims to replace poles and the overhead plants within the area bounded by Pape, Selkirk, Woodycrest and Danforth Avenue
- Maintenance of the existing 4kV system in this area is very costly due to the condition of the plant and unavailability of some parts on the market.
- The condition of the distribution plant along with obsolete non-standard equipment, and old poles plays an integral part in the overall reliability of an overhead distribution system. As evidenced in the ACA, there are almost 1100 poles requiring replacement over the next three years. Also, for pole-top transformers, almost 350 units are required to be replaced over the next three years.
- It is proposed that the area be converted to 27.6kV overhead as opposed to 4kV refurbishing. This will consist of three-phase and single-phase overhead extensions from the existing 27.6kV overhead plant from the former City of East York. This option was not available prior to amalgamation due to city border crossings
- This voltage conversion has the added benefit of reducing system losses and will ultimately aid in the goal of reducing power consumption in the province of

Ontario.

- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Alternatives:

- Conversion to 13.8 kV is costly due to long distances of stations and feeders. Also, at the closest 13.8 kV stations, there are no circuit breaker positions available
- Refurbish the 4 kV existing 4 kV system. T will be difficult to maintain a spare parts inventory for this alternative. Also, this will not address future capacity issues

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration
- Reduction of system line losses

PROJECT #: W07278

Business Case Summary

Project Title: Overhead rehabilitation – installation of new 27.6kV SCADA switches

Estimated Cost: $1,827,000

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI.
- To improve substandard communication for existing remote switches.

Description:

- Convert 23 switch locations of old existing Bell communication line using the new wireless communication system and new SCADA operated switches in Scarborough area.
- Existing switches are aging and have non-standard communication components
- Existing switches have old and non-reliable battery and charger
- Existing failing radio system that has potential to disable remaining radio communication
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- Spare parts for existing equipment difficult to attain
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location should is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- This project will improve reliability to all feeders associated with Scarborough TS located in the east portion of the city
- THESL will conduct this work in accordance with the OHSA and associated

regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued rental payment to Bell and reduction in reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- Eliminate rental cost of the Bell leased lines.
- End of Life replacement for old assets within the remote switch class
- Immediately after the first few switches are replaced, the spare parts issue is considerably improved
- The new RTUs are “Feeder Automation” ready (should THESL decide to pursue this initiative)

PROJECT #: W08131

Business Case Summary

Project Title: Feeder extension 85M5: Bathurst TS

Estimated Cost: $766,000

Portfolio: Overhead

Objective:

- To address overload situation on 85M5 feeder.
- To accommodate future load growth due to development in the area.

Description:

- Liberty Development Corporation has proposed to develop the north-west corner of W. R. Allen Road and Sheppard Avenue West. Seven buildings are proposed with a total of 1,500 units.
- The existing feeder in the area cannot accommodate this load. Therefore, nearby feeders need to be extended into the area. It is proposed to utilize the 85M1 and 85M5 to supply this development.
- In order to extend the 85M5 to the site, the existing pole line along Sheppard Avenue West from Goddard Street to W. R. Allen must be rebuilt to accommodate a new double circuit vertical construction. The total distance is about 1.5 km.
- The new customer connection is scheduled for July 2008. Therefore, this project must be completed by July 2008.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Not proceeding with this investment will result in loading existing facilities beyond ratings with consequent equipment damage and reduction to system reliability.

Results:

- Improvements in reliability.
- Increased capacity to accommodate new customers
- Primary assets at their end of service life will be replaced.
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood

PROJECT #: W08191

Business Case Summary

Project Title: Voltage Conversion 4kV to 27.6kV on Bathurst St: Avenal to Tichester

Estimated Cost: $650,000

Portfolio: Overhead

Objective:

- To convert a portion of 4kV to 27.6kV. on Bathurst Street, Avenal Drive and Tichester Rd
- To create a tie point between Fairbanks feeders 35M4 and 35M9 on Bathurst St for superior reliability.

Description:

- The peak load on B-3-CP has exceeded the alarm condition of over 450 to 500 Amps.
- The 4 kV distribution system on Bathurst Street is old and heavily contributes to the high 4 kV loads on feeder B-3-CP.
- To reduce losses and improve the reliability of supply in the area, the 27.6kV at the two furthest ends will be extended to create a SCADA controlled tie point between feeders 35M4 and 35M9 on Bathurst Street.
- The aging 4kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Alternatives:

- Various 13.8 kV and 27.6 kV feeders in the nearby area were considered to be brought in this area for voltage conversion.
- The best alternative is to bring in the York feeder 27.6kV feeders - YK 35M4

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Virtual elimination of maintenance costs over the immediate term.
- Significant boost to electrical reliability for this area.
- Reduction of system line losses

NETWORK

Table 4: Network Projects

Project Number	Project Title	Estimated Cost ($)
N08144	Network Transformer Replacement 50 units	5,000,000
N08148	ATS Replacement	654,000
Overall Cost		5,654,000

PROJECT #: N08144

Business Case Summary

Project Title: Network Transformer Replacement 50 units

Estimated Cost: $5,000,000

Portfolio: Network

Objective:

- To replace 50 network transformers and associated fibre top protectors that are deemed unreliable as a result of past failures.

Description:

- This project is aimed towards the replacement of network transformers and associated fibre top protectors throughout the city.
- Fibre top protectors are vulnerable to salty water. The conductive salty water causes severe corrosion of the electrical connections. Excessive heat could also be generated on the electrical connections of the protector as a result of the salty water and the creation of an arc could cause a fire in the vault. To avoid such risk, it is necessary to replace the fibre top protectors and the associated transformers since new protectors cannot be fitted on the existing old transformers.
- Replace approximately 50 transformers based on condition assessment and prioritize by age of the transformers and replacement of fibre top protectors.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this project will result in further equipment deterioration and eventual failure of transformers and protectors, which will reduce the reliability of the network system. Catastrophic failure of network transformer could jeopardize public safety as well, so a proactive replacement program is necessary.

Results:

- Safe and reliable power supply to the downtown customers will be secured.
- Safe equipment operation will be achieved.

PROJECT #: N08148

Business Case Summary

Project Title: ATS Replacement

Estimated Cost: $654,000

Portfolio: Network

Objective:

- To replace five existing ATSs using Stand-Alone Protectors.

Description:

- ATSs owned by THESL installed in customer owned transformer vaults or rooms are approaching its end of life and have become problematic over the past.
- These units fail to transfer load from the normal to the standby during a feeder outage and has resulted in lengthy customers down time
- Replace five of these obsolete ATSs with Stand-Alone Protectors
- Before deciding to replace the ATS with stand-alone protectors, the existing load and the reliability requirement of the customers was reviewed in order to justify the investment
- All ATSs are be phased out at the rate of five per year

Deferral of project will result in further equipment deterioration and failure. As a result:

- Customer satisfaction is reduced
- System reliability is decreased
- Unplanned maintenance requirements increase

Alternatives:

- Transfer the customers to network system. Since the customers are located far from the network system, it makes this alternative costly.
- Supply the customer with other types of distribution system. The reliability requirement of the customers can not be met with any other type of distribution system

Results:

- Increased reliability.
- Increased customer satisfaction.
- Less requirement of unplanned maintenance work.

TRANSFORMER STATION

Table 5: Transformer Station Projects

Project Number	Project Title	Estimated Cost ($)
S08132	Glengrove Transformer Station: Replace A1-A2 Switchgear	3,000,000
S08153	George & Duke MS: Replace A5-A6 Switchgear	3,000,000
S08190	Carlaw TS: Replace A1-A2 Switchgear	3,000,000
Overall Cost		**9,000,000**

PROJECT #: S08132

Business Case Summary

Project Title: Glengrove Transformer Station: Replace A1-A2 Switchgear

Estimated Cost: $3,000,000

Portfolio: Transformer Station

Objective:

- To replace the existing A1-A2 switchgear at Glengrove station

Description:

- The A1-A2 switchgear at Glengrove TS is 47 years old and has reached the end of its service life.
- The General Electric type magnetic air-blast circuit breakers in Glengrove Transformer Station are performing poorly, as these circuit breakers have malfunctioned while in service.
- Replacement parts for the switchgear and circuit breakers are no longer being manufactured. Any part required has to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The existing switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure
- The load capacity of the switchgear is also limited to 2000A and limits ability to serve new load as it is below the standard switchgear capacity rating.
- The project involves the replacement of the switchgear with 3000A, air insulated arc resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with

contingencies, increased safety risk and increased operating costs.

Alternatives:

- Replace the switchgear with gas insulated switchgear rather than with air insulated metal clad switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance
- Improved system reliability and reduced risk.
- Increased capacity to meet future load growth.
- Improved personnel safety.
- Reduced maintenance costs and decreased maintenance time.

PROJECT #: S08153

Business Case Summary

Project Title: George & Duke MS: Replace A5-A6 Switchgear

Estimated Cost: $3,000,000

Portfolio: Transformer Station

Objective:

- To replace the existing A5-A6 switchgear at George & Duke station

Description:

- The A5-A6 switchgear at George & Duke MS has reached the end of its service life. The circuit breakers within this station are 57 years old.
- The existing circuit breakers are of the air blast type and are obsolete. Replacement parts are no longer being manufactured. Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The air blast circuit breakers at thisstation have additional maintenance costs due to the added expense of renewing and maintaining the air supply system needed for breaker operation.
- The existing switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure.
- The project involves the replacement of the switchgear with 3000 A air insulated arc-resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with contingencies, increased safety risk and increased operating costs.

Alternatives

- Replace the switchgear with gas insulated switchgear rather than with air insulated metal clad switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance.
- Improved system reliability and reduced risk.
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time.

PROJECT #: S08190

Business Case Summary

Project Title: Carlaw TS: Replace A1-A2 Switchgear

Estimated Cost: $ 3,000,000

Portfolio: Transformer Station

Objective:

To replace the A1-A2 Switchgear at Carlaw station

Description:

- The A1-A2 switchgear has reached end of its service life as the switchgear is 57 years old.
- The existing circuit breakers are of the air blast type and are obsolete. Replacement parts are no longer being manufactured. Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The air blast circuit breakers at this station have additional maintenance costs due to the added expense of renewing and maintaining the air supply system needed for breaker operation.
- The basic design of the switchgear, being an open brick structure, is a safety concern to operating personnel of THESL due to the exposed live parts of the switchgear.
- The switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure.
- The project involves the replacement of the switchgear with 3000 A air insulated arc-resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with contingencies, increased safety risk and increased operating costs.

Alternatives:

- Replace the switchgear with gas insulated switchgear rather than with air insulated metal clad switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance.
- Improved system reliability and reduced risk.
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time.

MUNICIPAL SUBSTATION

Table 6: Municipal Substation Projects

Project Number	Project Title	Estimated Cost ($)
S08081	Design for 2009 projects - Stations	700,000
S08170	Defoe Municipal Station: Replace 4.16 kV Oil Circuit Breakers	645,000
Overall Cost		1,345,000

PROJECT #: S08081

Business Case Summary

Project Title: Design for 2009 projects - Stations

Estimated Cost: $700,000

Portfolio: Municipal Substation

Objective:

- To cover the cost of stations projects being designed for construction in 2009.

Description:

- The designer will use the issued project documentation for work coordinated between Stations and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Designing include:
  - Create drawings and specifications
  - Field work
  - Prepare bill of materials and order material and equipment.
  - Prepare details estimate
  - Arrange for work permits pursuant to provincial and federal legislation
  - Send projects out for construction.
  - Administer civil contracts

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns

- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Efficient resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: S08170

Business Case Summary

Project Title: Defoe Municipal Station: Replace 4.16 kV Oil Circuit Breakers

Estimated Cost: $645,000

Portfolio: Municipal Substation

Objective:

- To replace all the existing oil circuit breakers at Defoe Municipal Station with vacuum circuit breakers.

Description:

- The oil circuit breakers at the station have reached the end of their service life as the breakers are well over 50 years old.
- The oil circuit breakers are located indoors and pose a fire and explosion risk in an eventful failure.
- Replacement parts for the circuit breakers are no longer being manufactured. Any part required has to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The project involves the replacement of the oil circuit breakers with vacuum circuit breakers within the same existing switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the equipment, making it unsafe to operate and increasingly expensive to maintain.

Alternatives:

- Converting the 4.16KV customers served by this substation to 13.8KV and then abandoning the station and switchgear
- Replacing the entire switchgear with circuit breakers with air insulated arc-resistant switchgear.

Result:

- More reliable equipment performance
- Improved system reliability and reduced risk
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time
- Reduced maintenance cost

REACTIVE WORK

Table 7: Reactive Work Projects

Project Number	Project Title	Estimated Cost ($)
C08199	Capital Replacement of Overhead Equipment - West	4,189,000
C08200	Capital Replacement of Overhead Equipment - East	2,296,000
C08246	Capital Replacement of Underground Equipment - East	4,689,000
C08247	Capital Replacement of Underground Equipment - West	3,302,000
Overall Cost		14,476,000

PROJECT #: C08199

Business Case Summary

Project Title: Capital Replacement of Overhead Equipment - West

Estimated Cost: $4,189,000

Portfolio: Overhead

Objective:

The goal of this program is to maintain the reliability of supply.

Under this project, like-for-like damaged or deteriorated overhead equipment replacement is performed for the west portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby

assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT#: C08200

Business Case Summary

Project Title: Capital Replacement of Overhead Equipment - East

Estimated Cost: $2,296,000

Portfolio: Overhead

Objective:

The goal of this program is to maintain the reliability of supply.

Under this project, like-for-like damaged or deteriorated overhead equipment replacement is performed for the east portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby

assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C08246

Business Case Summary

Project Title: Capital Replacement of Underground Equipment - East

Estimated Cost: $4,689,000

Portfolio: Underground Rehabilitation

Objective:

The goal of this program is to maintain the reliability of supply.

Under this project, like-for-like damaged or deteriorated underground equipment replacement is performed for the east portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby

assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C08247

Business Case Summary

Project Title: Capital Replacement of Underground Equipment - West

Estimated Cost: $3,302,000

Portfolio: Underground Rehabilitation

Objective:

The goal of this program is to maintain the reliability of supply.

Under this project, like-for-like damaged or deteriorated underground equipment replacement is performed for the west portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby

assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECTS $500K AND OVER FOR 2009

UNDERGROUND DIRECT BURIED

Table 1: Underground – Direct Buried Projects

Project Number	Project Title	Estimated Cost ($)
E07315	Underground rehabilitation at Goldhawk Tr and Alton Towers Cl	9,851,000
E08113	100-158 Burrows NAH9M23 UG repl	1,733,822
E08115	Underground Rehabilitation at Crow Trail	4,680,000
E08116	Underground Rehabilitation at Sewells Rd and Morningside Av	5,310,000
E08117	John Tabor NT47M3 UG repl	4,860,000
E08130	Braymore (Meadowvale Park Estate 1) NA47M13 UG Repl	3,080,000
E09084	Invergordon-Tineta (West Hill Meadows) KH-F2 UG Repl and VC	1,320,000
E09085	Sexton Lesbos Hines McNicoll SS68-F1 UG Repl	2,420,000
E09086	Baylawn (West Hill Redevelopment) SG-F2 UG Repl and VC	2,640,000
E09087	Bridlewood and Tambrook area Feeder NA502M22	1,430,000
E09088	Victoria Woods Subdivision Feeder NA47M17	4,510,000
E09089	Foxdale-Beardmore area Feeder SS64-F3	880,000
E09091	Blacktoft NT47M7 UG Repl (Meadowvale Park Estate 2)	3,630,000
W09081	Underground rehabilitation in the area of Ladyshot, feeder # SS58F1	600,000
W09097	Underground rehabilitation of direct buried cable for feeder 85M3 in Whitehorse/Kodiak area	780,000
W09098	Underground rehabilitation of direct buried cable for feeder 85M4 in Derrydown/Ikley area	2,280,000
Overall Cost		50,004,822

PROJECT #: E07315

Business Case Summary

Project Title: Underground rehabilitation at Goldhawk Tr and Alton Towers Cl

Estimated Cost: $9,851,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT63M12.
- To rebuild to modern standards the subdivisions on Goldhawk Tr and Alton Tower Cl bounded by Steeles Avenue, McCowan Rd, McNicollAvenue and Brimley Rd.

Description:

- There have been six unplanned outages in this area over the past two years. These outages have been unusually long duration outages contributing to almost two million total customer minutes out. The total number of customer interruptions during these six outages was approximately 2000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the Asset Condition Assessment ("ACA"), there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.

- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with switches and fuses within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards

which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08113

Business Case Summary

Project Title: E08113 100-158 Burrows NAH9M23 UG repl

Estimated Cost: $1,733,822

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAH9M23.
- To rebuild to modern standards the subdivisions on townhomes complex at #100-#158 Burrows Hall Blvd. and #2 Dialing Gate.

Description:

- There have been several unplanned outages in this area over the past two years. This feeder has contributed to over two thousand total customer interruptions over the last two years as well as contributing to almost thirty thousand total customer minutes out.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08115

Business Case Summary

Project Title: Underground Rehabilitation at Crow Trail

Estimated Cost: $4,680,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAR26M34
- To rebuild to modern standards the subdivisions on Crow Trail bounded by Finch Av, Neilson Rd, McLevin Av, and Markham Rd.

Description:

- There have been several unplanned outages in this area over the past two years. These outages have been unusually long duration outages contributing to over four hundred thousand customer minutes out. The total number of customer interruptions was approximately three thousand four hundred.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with switches and fuses within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized

to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08116

Business Case Summary

Project Title: Underground Rehabilitation at Sewells Rd and Morningside Av

Estimated Cost: $ 5,310,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M3
- To rebuild to modern standards the subdivisions bounded by Morningside Av, Sewells Rd, Finch Av, and Neilson Rd.

Description:

- This feeder has undergone several unplanned outages in the past two years. These outages have been unusually long duration outages contributing to approximately 1.5 million customer minutes out. The total number of customer interruptions was approximately 30,000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08117

Business Case Summary

Project Title: E08117 John Tabor NT47M3 UG repl (Malvern 10, #36 on list)

Estimated Cost: $4,860,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M3
- To rebuild to modern standards the subdivisions on Malvern 1

Description:

- This feeder has contributed to over sixty thousand total customer interruptions over the last to years. Also, this feeder has contributed to over 1.5 million total customer minutes out over the last two years.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters will be replaced with switches and fuses within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E08130

Business Case Summary

Project Title: E08130 Braymore (Meadowvale Park Estate 1) NA47M13 UG Repl

Estimated Cost: $ 3,080,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA47M13
- To rebuild to modern standards the subdivision Meadowvale Park Estate 1 on Braymore Blvd.

Description:

- There have been six unplanned outages in this area over the past two years (2005-2006). These outages have been unusually long duration outages contributing to almost 250,000 total customer minutes out. The total number of customer interruptions during these six outages was approximately 4,000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E09084

Business Case Summary

Project Title: E09084 Invergordon–Tineta (West Hill Meadows) KH-F2 UG Repl and VC

Estimated Cost: $1,320,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder KH-F1, NAH9M25.
- To rebuild to modern standards the subdivision West Hill Meadows on Invergordon Avenue and Tineta Cr.

Description:

- There have been two unplanned outages in this area over the past five years (from 2001 to 2005). These outages have been unusually long duration outages contributing to almost 33,385 total customer minutes out.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios
- Reduction of system losses

PROJECT #: E09085

Business Case Summary

Project Title: E09085 Sexton Lesbos Hines McNicoll SS68-F1 UG Repl

Estimated Cost: $2,420,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SS68-F1.
- To rebuild to modern standards the subdivisions on Sexton Cr, Lesbos Rd, Hines Dr, McNicoll Avenue

Description:

- There have been eight unplanned outages in this area during 2001 to 2005. These outages have been unusually long duration outages contributing to almost 162,000 total customer minutes out. The total number of customer interruptions during these eight outages was approximately 2,300.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E09086

Business Case Summary

Project Title: E09086 Baylawn (West Hill Redevelopment) SG-F2 UG Repl and VC

Estimated Cost: $2,640,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SG-F2, NT63M5.
- To rebuild to modern standards the subdivision West Hill Meadows on Invergordon Avenue and Tineta Cr.

Description:

- There have been several unplanned outages in this area over the past three years. These outages have been unusually long duration outages contributing to almost 40,000 total customer minutes out.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E09087

Business Case Summary

Project Title: E09087 Bridlewood and Tambrook area Feeder NA502M22

Estimated Cost: $1,430,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA502M22
- To rebuild to modern standards the subdivision bounded by Bridletowne, L'Amoreaux, and Brookmill.

Description:

- This feeder has experienced several unplanned outages. These outages have been unusually long duration outages contributing to almost 800,000 total customer minutes out and over 3,000 total customer interruptions.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E09088

Business Case Summary

Project Title: E09088 Victoria Woods Subdivision Feeder NA47M17

Estimated Cost: $4,510,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA47M17
- To rebuild to modern standards the subdivision Meadowvale, HWY401, Sheppard, Ellesmere.

Description:

- This feeder has experienced several unplanned outages. These outages have been unusually long duration outages contributing to almost 200,000 total customer minutes out and over 8,000 total customer interruptions.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E09089

Business Case Summary

Project Title: E09089 Foxdale-Beardmore area Feeder SS64-F3

Estimated Cost: $880,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SS64-F3
- To rebuild to modern standards the subdivision bounded by Bayview, Leslie, Steeles, and Cummer

Description:

- The distribution system was built in the late seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree

retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased

- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E09091

Business Case Summary

Project Title: E09091 Blacktoft NT47M7 UG Repl (Meadowvale Park Estate 2)

Estimated Cost: $3,630,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M7
- To rebuild to modern standards the subdivision Meadowvale Park Estate 2 on Braymore Blvd and Blacktoft Dr.

Description:

- There have been six unplanned outages in this area in the span of one year. These outages have been unusually long duration outages contributing to almost 42,000 total customer minutes out.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W09081

Business Case Summary

Project Title: Underground rehabilitation in the area of Ladyshot, feeder # SS58F1

Estimated Cost: $600,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Jamestown Crescent area.

Description:

- The area is with 13.8 kV with neighbouring area at 27.6 kV distribution. It has been decided to leave this area at 13.8 kV
- The distribution system was built in the sixties as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W09097

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder 85M3 in Whitehorse/Kodiak area

Estimated Cost: $780,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Whitehorse/Kodiak area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during

future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W09098

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder 85M4 in Derrydown/Ikley area

Estimated Cost: $ 2,280,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Derrydown/Ikley area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better

protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

UNDERGROUND REHAB

Table 2: Underground Rehab Projects

Project Number	Project Title	Estimated Cost ($)
E08220	E08220 Leeward 53M9 UG	815,428
DC_E09128	Permanent Cut Repair Restoration - East	1,200,000
DC_E09129	System Enhancement: Underground Cable Rehabilitation – East	1,454,600
DC_W09132	System Enhancement: Underground Cable Rehabilitation – West	1,455,000
DC_W09134	Permanent City Cut Restoration – West	800,000
E09116	Design for 2010 Projects – Distribution Projects East	1,200,800
W09145	Design for 2010 Projects – Distribution Projects West	1,800,000
W09101	Rear Lot - Underground conversion 4 kV to 27.6 kV: Forest Hill area	4,000,000
W09102	Underground conversion 4 kV to 27.6 kV: Silverstone PFF2 Rear Lot VC	2,500,000
W09123	Finch T.S. Egress Cable ENHN M25, 26 & 27 & Others	1,500,000
W09125	High Level TS Feeder A-47-H upgrade and primary rearr/ench	650,000
W09157	W09157 Strachan Feeder Leakers UG repl	625,868
E09170	Rear Lot 43M24	600,000
Overall Cost		**18,601,696**

PROJECT #: E08220

Business Case Summary

Project Title: E08220 Leeward 53M9 UG

Estimated Cost: $815,428

Portfolio: Underground Rehabilitation

Objective:

- To address end-of-life conditions of the XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 53M9.
- To rebuild existing "Radial fed" transformers vaults and convert them to “Loop fed” vaults.
- To rebuild to modern standards (replace existing Delta connected transformers with Wye connected transformers) on 95-140 Leeward Glenway.

Description:

- There have been two unplanned outages in this area over the past two years. These outages contributed to almost 4500 total customer minutes out.
- In the project area each vault houses three-250kVA 27.6/.208kV transformers connected on primary as Delta (secondary Y) – a non standard installation. (In 2005 an explosion on a transformer blew the door off with serious damage to the vault. Aftermath necessary replacement and modifications were done on the burnt T10926 transformers only.)
- The distribution system was built in the seventies (1972) as an underground distribution system, with partial direct buried primary and secondary cables and with submersible transformer in vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in

this area.

- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, all the primary delta connected transformers will be replaced with standard Y-Y connected transformers with standard fuses. For better reliability the transformers will be installed in a loop system eliminating the previous radial feed.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: DC_E09128

Business Case Summary

Project Title: Permanent Cut Repair Restoration - East

Estimated Cost: $1,200,000

Portfolio: Underground Rehabilitation

Objective:

- To compensate the City of Toronto for costs they incur to permanently repair city infrastructure such as roads, sidewalks and boulevards in the east portion of the city.

Description:

- In the process of undertaking (usually) underground construction work, THESL is required to break into existing City of Toronto infrastructure such as roads, sidewalks, and boulevards. Once the THESL work is completed, the City of Toronto's contractors repair/restore the damaged infrastructure. All efforts are made between THESL, the City of Toronto, and a number of other utilities to avoid conflict of schedules. Furthermore, co-ordination is made in order to facilitate efficiencies such as the agreement between utilities of joint-use trenches.

- Timely cut-repairs are required right away in order to address the following issues:
    - Customer complaints due to unsightly landscape
    - Potential public safety hazards
    - Exposure to further financial risk

Deferral of this project would unduly prolong the presence of fenced construction areas. This would impede the flow of pedestrian and vehicular traffic in the area concerned. Deferral will also lead to non-compliance with established City of Toronto regulations

Results:

- Compliance with City of Toronto regulations
- Improved public safety
- Mitigation of financial risk

IP REFERENCE #: DC_E09129

Business Case Summary

Project Title: System Enhancement: Underground Cable Rehabilitation - East

Estimated Cost: $1,454,600

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of unplanned capital investments related to underground assets in the east portion of the city. For the most part, engineering and design is required
- To resolve unplanned underground infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to underground assets.
- To address defective underground plant that poses unforeseen significant risk to system reliability.

Description:

- This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as cable chambers, vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with

consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

- Equipment replacement is required in order to address the following issues:
  - Customer complaints due to extended outages
  - Potential poor system reliability performance due to increased stress on nearby assets
  - Potential public safety concerns
  - Potential environmental concerns
  - Potential THESL personnel safety concerns
  - Exposure to further financial risk caused by damage to other associated assets
  - Maintain operating conditions; i.e., avoid second contingency conditions
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels

- Mitigate localized customer outage duration

IP REFERENCE #: DC_W09132

Business Case Summary

Project Title: System Enhancement: Underground Cable Rehabilitation – West

Estimated Cost: $1,455,000

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of unplanned capital investments related to underground assets in the west portion of the city. For the most part, engineering and design is required
- To resolve unplanned underground infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to underground assets.
- To address defective underground plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as cable chambers, vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to

capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner

- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W09134

Business Case Summary

Project Title: Permanent City Cut Restoration – West

Estimated Cost: $800,000

Portfolio: Underground Rehabilitation

Objective:

To compensate the City of Toronto for costs they incur to permanently repair city infrastructure such as roads, sidewalks and boulevards in the west portion of the city.

Description:

In the process of undertaking (usually) underground construction work, THESL is required to break into existing City of Toronto infrastructure such as roads, sidewalks, and boulevards. Once the THESL work is completed, the City of Toronto's contractors repair/restore the damaged infrastructure. All efforts are made between THESL, the City of Toronto, and a number of other utilities to avoid conflict of schedules. Furthermore, co-ordination is made in order to facilitate efficiencies such as the agreement between utilities of joint-use trenches.

Timely cut-repairs are required right away in order to address the following issues:

- Customer complaints due to unsightly landscape
- Potential public safety hazards
- Exposure to further financial risk

Deferral of this project would unduly prolong the presence of fenced construction areas. This would impede the flow of pedestrian and vehicular traffic in the area concerned. Deferral will also lead to non-compliance with established City of Toronto regulations.

Results:

- Compliance with City of Toronto regulations
- Improved public safety
- Mitigation of financial risk

PROJECT #: E09116

Business Case Summary

Project Title: Design for 2010 Projects – Distribution Projects East

Estimated Cost: $1,200,800

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of designing projects for construction in 2010. These designs encompass distribution projects located in the east portion of the city.

Description:

- The designer will use the issued project documentation for work coordinated between East Construction and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.

Designing include:

- Create drawings and specifications
- Field work
- Prepare bill of materials and order material and equipment.
- Prepare detailed estimate
- Arrange for work permits pursuant to provincial and federal legislation
- Send projects out for construction.
- Administer civil contracts

Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns
- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Optimal resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: W09145

Business Case Summary

Project Title: Design for 2010 Projects – Distribution Projects West

Estimated Cost: $1,800,000

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of designing projects for construction in 2010. These designs encompass distribution projects located in the east portion of the city.

Description:

- The designer will use the issued project documentation for work coordinated between West Construction and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.

Designing include:

- Create drawings and specifications
- Field work
- Prepare bill of materials and order material and equipment.
- Prepare detailed estimate
- Arrange for work permits pursuant to provincial and federal legislation
- Send projects out for construction.
- Administer civil contracts

Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns
- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Optimal resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: W09101

Business Case Summary

Project Title: Rear Lot - Underground conversion 4 kV to 27.6 kV: Forest Hill area

Estimated Cost: $4,000,000

Portfolio: Underground Rehabilitation

Objective:

- To relocate primary and secondary rear fed distribution to front lot underground
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address age and difficulty for accessing THESL owned equipment

Description:

- To address deteriorating rear lot distribution in the Forest Hill area bounded by Bathurst Street, Briar Hill, Allen Express Way and Ridelle Avenue
- To convert the 4kV distribution in the rear to 27.6kV underground distribution in the front using feeder 35M6 on Bathurst St.
- This project has been selected based on criteria used to prioritize rear lot plants
- The criteria used are:
    - Plant age
    - Number of customers
    - Primary voltage
    - Adjacent area's primary voltage
    - Adjacent area's construction type
    - Tree density
    - Customer satisfaction

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in continued repeat service calls for localized outages with associated Customer service degradation and eventual widespread outages and escalating operating costs. The existing 4 kV primary distribution in this area is beyond its service life and the rear lot distribution in this mature area adds to the ongoing maintenance costs.

Alternatives:

- A number of alternatives were analyzed and compared. The only cost and safety feasible alternative was this changeover permitting long run improvements in the way electrical services can be provided and maintained in this area.

Results:

- Reduced maintenance costs over the immediate term
- Improvements in servicing by THESL field crews
- Improve reliability
- Safer distribution system
- Easy accessibility for crews and less disruption to customers
- Reduction of system losses

PROJECT #: W09102

Business Case Summary

Project Title: Underground conversion 4 kV to 27.6 kV: Silverstone PFF2 Rear Lot VC

Estimated Cost: $2,500,000

Portfolio: Underground Rehabilitation

Objective:

- To relocate primary and secondary rear fed distribution to front lot underground
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address age and difficulty for accessing THESL owned equipment

Description:

- To address deteriorating rear lot distribution in the Silverstone area
- To convert the 4kV distribution in the rear to 27.6kV underground distribution in the front.
- This project has been selected based on criteria used to prioritize rear lot plants
- The criteria used are:
    - Plant age
    - Number of customers
    - Primary voltage
    - Adjacent area's primary voltage
    - Adjacent area's construction type
    - Tree density
    - Customer satisfaction

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB

requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in continued repeat service calls for localized outages with associated Customer service degradation and eventual widespread outages and escalating operating costs. The existing 4 kV primary distribution in this area is beyond its service life and the rear lot distribution in this mature area adds to the ongoing maintenance costs.

Alternatives:

- A number of alternatives were analyzed and compared. The only cost and safety feasible alternative was this changeover permitting long run improvements in the way electrical services can be provided and maintained in this area.

Results:

- Reduced maintenance costs over the immediate term
- Improvements in servicing by THESL field crews
- Improve reliability
- Safer distribution system
- Easy accessibility for crews and less disruption to customers
- Reduction of system losses

PROJECT #: W09123

Business Case Summary

Project Title: Finch T.S. Egress Cable ENHN M25, 26 & 27 & Others

Estimated Cost: $1,500,000

Portfolio: Underground Rehabilitation

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of cable in the Finch TS area.

Description:

- The 27.6 kV cables and ducts in this area have reached end of life. Some feeders in the neighbouring ducts have failed and have been replaced.
- It has been decided to replace the other feeders as well that have the same age and loading conditions.
- Some existing cables are 1000 MCM Aluminium, whereas for loading conditions, 1000 MCM Copper is recommended.
- At the same time some Finch TS feeders need re-arranging for load balancing.
- The distribution system was built in the earlier than sixties as an underground distribution system. There is a necessity for replacement of distribution system in this area.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative
- This project will replace the cables.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced.
- THESL will conduct this work in accordance with the OHSA and associated

regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios.

PROJECT #: W09125

Business Case Summary

Project Title: High Level TS Feeder A-47-H upgrade and primary rearr/ench

Estimated Cost: $650,000

Portfolio: Underground Rehabilitation

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of cable in the High Level TS area.

Description:

- The 13.8 kV cables and ducts in this area have reached end of life. Some ducts are collapsing and need rebuild.
- At the same time some High Level feeders need re-arranging for load balancing.
- The distribution system was built in the earlier than fifties as an underground distribution system. There is a necessity for replacement of distribution system in this area.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative
- This project will rebuild the old, ducts and cables.
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act,

and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W09157

Business Case Summary

Project Title: W09157 Strachan Feeder Leakers UG repl

Estimated Cost: $625,868

Portfolio: Underground Rehabilitation

Objective:

- To address the leaking condition of PILC cables, joints and potheads and remove the Raychem patches,
- To prevent potential emergency situations that cause high restoration costs and overload conditions,
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeders out of Strachan (T) station.

Description:

- The quantity of cable leakers has increased over the last decade. This scenario is susceptible to instances where costs could substantially increase when restorations are required during an emergency scenario. Furthermore, during such instances, cables would likely be subjected to potentially damaging overload conditions.
- Based on the last years leaker database there are presently 44 leaking items on feeders out of Strachan station – items of 19 cable, 12 sleeve, seven pothead replacement and six patches.
- The Underground Environmental Health and Safety (UGEH&S) Committee suggested (minute #UG-003) to allocate enough funds to reduce the quantity of leakers presently within the system.
- UGEH&S Committee (minute #UG-167) also treats any Raychem Heat Shrink patches used on cables as a temporary measure to stop a leak and recommends

replacing it as early as possible.

- Asset Management has decided to initiate a planned leaker repair program that will address all the outstanding leakers. The investment in the first few years will be directed to address the feeders in areas or out of substations where presence of leakers are found in concentrated numbers.
- This project will repair/replace all leaking cables/splices, potheads and remove all existing Raychem Heat Shrink patches within the vicinity of Windsor (W) station. This investment will prevent potential emergency situations that cause high restoration costs and overload conditions, therefore improving system sustainability.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, increased risk of fire hazard and customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Full functionality of the Primary assets will be restored.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second

contingency scenarios

PROJECT #: E09170

Business Case Summary

Project Title: E09170 Rear Lot 43M24

Estimated Cost: $600,000

Portfolio: Underground Rehabilitation

Objective:

- To relocate primary and secondary rear fed distribution to front lot overhead
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address age and difficulty for accessing THESL owned equipment

Description:

- This project has been selected based on criteria used to prioritize rear lot plants
- The criteria used are:
    - Plant age
    - Number of customers
    - Primary voltage
    - Adjacent area's primary voltage
    - Adjacent area's construction type
    - Tree density
    - Customer satisfaction

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in continued repeat service calls for localized outages with associated Customer service degradation and eventual widespread outages and escalating operating costs

Alternatives:

- A number of alternatives were analyzed and compared. The only cost and safety feasible alternative was this changeover permitting long run improvements in the way electrical services can be provided and maintained in this area.

Results:

- Reduced maintenance costs over the immediate term
- Improvements in servicing by THESL field crews
- Improve reliability
- Safer distribution system
- Easy accessibility for crews and less disruption to customers

OVERHEAD

Table 3: Overhead Projects

Project Number	Project Title	Estimated Cost ($)
DC_E09131	System Enhancement: Overhead Rehabilitation – East	518,000
DC_W09133	System Enhancement: Overhead Rehabilitation - West	518,000
E07163	Overhead Rehabilitation – Installation of Remote Switches	1,419,726
E08050	Overhead rehabilitation – installation of new 27.6 kV SCADA switches in former North York area	1,520,000
E09117	Equipment Nomenclature Enhancement – East	1,900,000
W09042	Equipment Nomenclature Enhancement – West	1,900,000
W07111	W07111Sunnyside_Grden B-10-J OH VC Ph #2	550,000
W07297	Overhead & Underground Enhancement on North & South side of St Clair West between Wychwood Avenue and Westmount Avenue	1,100,000
W09095	Overhead Enhancement at Fisherville for feeder 85M7 OH	500,000
W09096	Voltage Conversion of 4 kV Parkdale MS Feeder B-3-8-PQ to 13.8 kV Dufferin TS	3,500,000
W09099	Overhead rehabilitation – installation of new 27.6kV SCADA switches in former North York area	1,200,000
W09103	Overhead Enhancement at Gracefield	800,000
W09104	Voltage Conversion 4kV Wiltshire Feeder B-1-2-W VC to 13.8 kV	2,500,000
W09124	Voltage Conversion of 4 kV Parkside Garden Feeder B-9-J OH VC PH#1	500,000
Overall Cost		**18,425,726**

IP REFERENCE #: DC_E09131

Business Case Summary

Project Title: System Enhancement: Overhead Rehabilitation - East

Estimated Cost: $518,000

Portfolio: Overhead

Objective:

- To cover the cost of unplanned capital investments related to overhead assets in the east portion of the city. For the most part, engineering and design is required
- To resolve unplanned overhead infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to overhead assets.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address defective overhead plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work

prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W09133

Business Case Summary

Project Title: System Enhancement: Overhead Rehabilitation - West

Estimated Cost: $518,000

Portfolio: Overhead

Objective:

- To cover the cost of unplanned capital investments related to overhead assets in the west portion of the city. For the most part, engineering and design is required
- To resolve unplanned overhead infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to overhead assets.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address defective overhead plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work

prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: E07163

Business Case Summary

Project Title: Overhead Rehabilitation – Installation of Remote Switches

Estimated Cost: $1,419,726

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI

Description:

- Install 17 remote switches in areas where there is a large number of connected customers, a high number of historical trunk faults, and where there are currently either zero or one remote switch associated with the feeder
- Existing manual switches are aging
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued rental payment to Bell and reduction in

reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- The new RTUs are “Feeder Automation” ready (should TH decide to pursue this initiative)

PROJECT #: E08050

Business Case Summary

Project Title: Overhead rehabilitation – installation of new 27.6 kV SCADA switches in former North York area

Estimated Cost: $1,520,000

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI.
- To improve substandard communication for existing remote switches.

Description:

- Replace 16 switch locations of old remote switches and three manual switches using the new wireless communication system and new SCADA operated switches in North York area.
- Existing switches are aging and have non-standard communication components
- Existing switches have old and non-reliable battery and charger
- Existing failing radio system that has potential to disable remaining radio communication
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- Spare parts for existing equipment difficult to attain
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location should is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- This project will improve reliability to all feeders associated with Scarborough TS located in the east portion of the city

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction in reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- End of Life replacement for old assets within the remote switch class
- The spare parts issue is considerably improved
- The new RTUs are “Feeder Automation” ready (should THESL decide to pursue this initiative)

IP REFERENCE #: E09117

Business Case Summary

Project Title: Equipment Nomenclature Enhancement – East

Estimated Cost: $1,900,000

Portfolio: Overhead

Objective:

- To re-label all the operable distribution devices across the distribution system according to a new consistent nomenclature standard.

Description:

- There are six legacy location identification approaches across the distribution system, some of which vary immensely from the others. This creates potential confusion to crews that may not be familiar with these standards and could pose operational hazards.
- In order to eliminate the potential hazards of improper operation, there is a need to harmonize the nomenclature. All devices need to be relabelled according to the new nomenclature standard.
- The new nomenclature also supports the new DMS System in Operation.
- In certain locations, THESL personnel are required to isolate the asset to be labelled. This requires a set of switching procedures to be followed according to THESL's work protect code
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

Deferral or failure to address these deficiencies could lead to inappropriate operation of equipment in the field.

Results:

- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios
- Mitigation of hazards to THESL personnel and public

IP REFERENCE #: W09042

Business Case Summary

Project Title: Equipment Nomenclature Enhancement – West

Estimated Cost: $1,900,000

Portfolio: Overhead

Objective:

- To re-label all the operable distribution devices across the distribution system according to a new consistent nomenclature standard.

Description:

- There are six legacy location identification approaches across the distribution system, some of which vary immensely from the others. This creates potential confusion to crews that may not be familiar with these standards and could pose operational hazards.
- In order to eliminate the potential hazards of improper operation, there is a need to harmonize the nomenclature. All devices need to be relabelled according to the new nomenclature standard.
- The new nomenclature also supports the new DMS System in Operation.
- In certain locations, THESL personnel are required to isolate the asset to be labelled. This requires a set of switching procedures to be followed according to THESL's work protect code
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

Deferral or failure to address these deficiencies could lead to inappropriate operation of equipment in the field.

Results:

- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios
- Mitigation of hazards to THESL personnel and public

PROJECT#: W07111

Business Case Summary

Project Title: W07111Sunnyside_Grden B-10-J OH VC Ph #2

Estimated Cost: $550,000

Portfolio: Overhead

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the operational flexibility of the grid

Description:

- The condition of the distribution plant along with obsolete non-standard equipment, and old poles plays an integral part in the overall reliability of an overhead distribution system. As evidenced in the ACA, there are almost 1100 poles requiring replacement over the next three years. Also, for pole-top transformers, almost 350 units are required to be replaced over the next three years.
- Maintenance of the existing 4 kV system in this area is costly due to the condition of the plant and unavailability of spare parts
- The assets in this area are old and less reliable, and in many cases, do not meet our current standards.
- This voltage conversion has the added benefit of reducing system losses and will ultimately aid in the goal of reducing power consumption in the province of Ontario
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration
- Reduction of system losses

PROJECT #: W07297

Business Case Summary

Project Title: Overhead & Underground Enhancement on North & South side of St Clair West between Wychwood Avenue and Westmount Avenue

Estimated Cost: $1,100,000

Portfolio: Overhead

Objective:

- To transfer 4 kV load on south and North side of St Clair onto to the other 4kV feeder in the area from Wychwood Avenue and Westmount Avenue

Description:

- The work involves in this project entails all overhead rearrangement required to eventually remove the overhead 4 kV trunk lines off St Clair Avenue. This is to accommodate a proposal from the City and TTC to install a Centre Pole Traction Railcar System
- Follow cost sharing arrangement between THESL and the City according to Public Services Works on Highway Act. Fifty percent of the cost will be covered by the City of Toronto.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Alternatives:

- Maintain 4 kV system and reroute plant

- Replace assets with an overhead 13.8 kV system
- Convert the overhead plant to underground, including newly constructed civil infrastructure and electrical distribution assets.

Results:

- Improve streetscape.
- Improve reliability reducing outage duration and frequency as a result of having an underground system on St Clair Avenue instead of overhead plant.
- Primary assets at their end of service life will be replaced.
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood

PROJECT #: W09095

Business Case Summary

Project Title: Overhead Enhancement at Fisherville for feeder 85M7 OH

Estimated Cost: $500,000

Portfolio: Overhead

Objective:

- This project funds to replace undersized overhead conductors in the area to enhance system reliability.

Description:

- Upgrade the overhead portion on Fisherville to full feeder conductor size of 556 kcmil Al.
- This section is a weak-link of the feeder because of the under-sized conductors (336 kcmil Al). This feeder provides backup to multiple feeders in the area. It would pose serious risk to the reliability of the system if it is not upgraded.
- Deferral of this work will result in continued reduction in reliability with resultant negative customer impacts.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Results:

- There will be improved feeder reliability beneficially affecting both outage duration and frequency.

- Primarily assets at their end-of-life will be replaced.

PROJECT #: W09096

Business Case Summary

Project Title: Voltage Conversion of 4 kV Parkdale MS Feeder B-3-8-PQ to 13.8 kV Dufferin TS

Estimated Cost: $3,500,000

Portfolio: Overhead

Objective:

- To convert a the complete 4 kV Parkdale MS Feeder B-3-8-PQ to 13.8 kV
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear at Parkdale Station.

Description:

- The 4 kV distribution system from Parkdale 4 kV switchgear is old and deteriorating.
- Moreover the 4 kV switchgear at the Parkdale MS is also old and needs replacement or should be decommissioned.
- To reduce losses and improve the reliability convert this area to 13.8 kV system supplied from the 13.8 kV switchgear at the Dufferin Station.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Reduction of maintenance costs over the immediate term.
- Significant improvement to electrical reliability for this area.
- Reduction of system losses

PROJECT #: W09099

Business Case Summary

Project Title: Overhead rehabilitation – installation of new 27.6kV SCADA switches in former North York area

Estimated Cost: $1,200,000

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI.
- To improve substandard communication for existing remote switches.

Description:

- Replace 15 switch locations of old remote switches using the new wireless communication system and new SCADA operated switches in North York area.
- Existing switches are aging and have non-standard communication components
- Existing switches have old and non-reliable battery and charger
- Existing failing radio system that has potential to disable remaining radio communication
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- Spare parts for existing equipment difficult to attain
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location should is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- This project will improve reliability to all feeders associated with Scarborough TS located in the east portion of the city
- THESL will conduct this work in accordance with the OHSA and associated

regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction in reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- End of Life replacement for old assets within the remote switch class
- The spare parts issue is considerably improved
- The new RTUs are “Feeder Automation” ready (should THESL decide to pursue this initiative)

PROJECT #: W09103

Business Case Summary

Project Title: Overhead Enhancement at Gracefield

Estimated Cost: $800,000

Portfolio: Overhead

Objective:

- To replace undersized overhead conductors in the area to enhance system reliability.

Description:

- Upgrade the overhead portion on Gracefield to full feeder conductor size of 556 kcmil Al.
- This section is a weak-link of the feeder because of the under-sized conductors (336 kcmil Al). This feeder provides backup to multiple feeders in the area. It would pose serious risk to the reliability of the system if it is not upgraded.
- Deferral of this work will result in continued reduction in reliability with resultant negative customer impacts.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Results:

- There will be improved feeder reliability beneficially affecting both outage duration and frequency.

- Primarily assets at their end-of-life will be replaced.

PROJECT #: W09104

Business Case Summary

Project Title: Voltage Conversion 4kV Wiltshire Feeder B-1-2-W VC to 13.8 kV

Estimated Cost: $2,500,000

Portfolio: Overhead

Objective:

- To convert a the complete 4kV Wiltshire Feeder B-1-2-W VC to 13.8 kV
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear at Wiltshire Station. Moreover the Wiltshire Station needs space to later replace 13.8 kV Switchgear.

Description:

- The 4 kV distribution system from Wiltshire 4 kV switchgear is old and deteriorating.
- To reduce losses and improve the reliability convert this area to 13.8kV system supplied from the 13.8 kV switchgear at the Wiltshire Station.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Alternatives:

- Various 13.8 kV and 27.6 kV feeders in the nearby area were considered to be brought in this area for voltage conversion.
- The best alternative is to use the 13.8 kV feeders from the Wiltshire Station

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Significant improvement to electrical reliability for this area.
- Reduction of system losses

PROJECT #: W09124

Business Case Summary

Project Title: Voltage Conversion of 4 kV Parkside Garden Feeder B-9-J OH VC PH#1

Estimated Cost: $ 500,000

Portfolio: Overhead

Objective:

- To convert the complete 4 kV Parkside Garden Feeder B-9-J OH VC PH#1
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear

Description:

- This 4 kV distribution system is old and deteriorating.
- To reduce losses and improve the reliability convert this area to 13.8 kV system supplied from the 13.8 kV System.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Significant improvement to electrical reliability for this area.

NETWORK

Table 4: Network Projects

Project Number	Project Title	Estimated Cost ($)
E09135	Network Transformer Replacement 25 units	2,500,000
W09119	Network Transformer Replacement 25 units	2,500,000
Overall Cost		5,000,000

PROJECT #: E09135

Business Case Summary

Project Title: Network Transformer Replacement 25 units

Estimated Cost: $2,500,000

Portfolio: Network

Objective:

- To replace 25 network transformers and associated fibre top protectors that are deemed unreliable as a result of past failures.

Description:

- This project is aimed towards the replacement of network transformers and associated fibre top protectors throughout the city.
- Fibre top protectors are vulnerable to salty water. The conductive salty water causes severe corrosion of the electrical connections. Excessive heat could also be generated on the electrical connections of the protector as a result of the salty water and the creation of an arc could cause a fire in the vault. To avoid such risk, it is necessary to replace the fibre top protectors and the associated transformers since new protectors cannot be fitted on the existing old transformers.
- Replace approximately 50 transformers based on condition assessment and prioritize by age of the transformers and replacement of fibre top protectors.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this project will result in further equipment deterioration and eventual failure of transformers and protectors, which will reduce the reliability of the network system. Catastrophic failure of network transformer could jeopardize public safety as well, so a proactive replacement program is necessary.

Results:

- Safe and reliable power supply to the downtown customers will be secured.
- Safe equipment operation will be achieved.

PROJECT #: W09119

Business Case Summary

Project Title: Network Transformer Replacement 25 units

Estimated Cost: $2,500,000

Portfolio: Network

Objective:

- To replace 25 network transformers and associated fibre top protectors that are deemed unreliable as a result of past failures.

Description:

- This project is aimed towards the replacement of network transformers and associated fibre top protectors throughout the City.
- Fibre top protectors are vulnerable to salty water. The conductive salty water causes severe corrosion of the electrical connections. Excessive heat could also be generated on the electrical connections of the protector as a result of the salty water and the creation of an arc could cause a fire in the vault. To avoid such risk, it is necessary to replace the fibre top protectors and the associated transformers since new protectors cannot be fitted on the existing old transformers.
- Replace approximately 50 transformers based on condition assessment and prioritize by age of the transformers and replacement of fibre top protectors.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this project will result in further equipment deterioration and eventual failure of transformers and protectors, which will reduce the reliability of the network system. Catastrophic failure of network transformer could jeopardize public safety as well, therefore a proactive replacement program is necessary.

Results:

- Safe and reliable power supply to the downtown customers will be secured.
- Safe equipment operation will be achieved.

TRANSFORMER STATION

Table 5: Transformer Station Projects

Project Number	Project Title	Estimated Cost ($)
S09043	Wiltshire Transformer Station: Replace A1-2W Switchgear	3,145,560
Overall Cost		3,145,560

Project #: S09043

Business Case Summary

Project Title: Wiltshire Transformer Station: Replace A1-2W Switchgear

Estimated Cost: $3,145,560

Portfolio: Transformer Station

Objective:

- To replace the existing A1-A2 switchgear at Wiltshire station

Description:

- The A1-2W switchgear is 53 years old and has reached the end of its service life.
- The existing circuit breakers are of the air blast type and are obsolete. Replacement parts are no longer being manufactured. Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The air blast circuit breakers at this station have additional maintenance costs due to the added expense of renewing and maintaining the air supply system needed for breaker operation.
- The switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure.
- The project involves the replacement of the switchgear with 3000 A air insulated arc-resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.
-

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with contingencies, increased safety risk and increased operating costs.

Alternatives:

Replace the switchgear with gas insulated switchgear rather than with air insulated switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance
- Improved system reliability and reduced risk
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time

MUNICIPAL SUBSTATION

Table 6: Municipal Substation Projects

Project Number	Project Title	Estimated Cost ($)
S09120	Design for 2010 projects - Stations	700,000
S09169	60 Eglinton Ave – Communication Equipment Removal & Relocation	1,200,000
Overall Cost		**1,900,000**

PROJECT #: S09120

Business Case Summary

Project Title: Design for 2010 projects - Stations

Estimated Cost: $700,000

Portfolio: Municipal Substation

Objective:

- To cover the cost of stations projects being designed for construction in 2010.

Description:

- The designer will use the issued project documentation for work coordinated between Stations and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Designing include:
  - Create drawings and specifications
  - Field work
  - Prepare bill of materials and order material and equipment.
  - Prepare details estimate
  - Arrange for work permits pursuant to provincial and federal legislation
  - Send projects out for construction.
  - Administer civil contracts

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns

- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Efficient resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

IP REFERENCE #: S09169

Business Case Summary

Project Title: 60 Eglinton Ave – Communication Equipment Removal & Relocation

Estimated Cost: $ 1,200,000

Portfolio: Municipal Substation

Objective:

- To remove all communication infrastructure prior to the 60 Eglinton Avenue building being sold.
- Optimize the downtown Toronto Hydro inter-substation communication network used for SCADA, Security Access System, telephony and data.

Description:

- 60 Eglinton Avenue is a former Control Centre for Toronto Hydro and as such remains a communication hub. Thirteen 25- or 50-pair underground copper telephone cables terminate and cross-connect at 60 Eglinton. Six 12- or 24-pair fibre optic cables terminate here as well.
- 60 Eglinton acts as a major node for the fibre optic Synchronous Optical Network ("SONET") multiplexing equipment which provides the transport for various low and high speed data circuits serving SCADA, System Access Security and corporate telephony/data requirements in the former downtown City of Toronto.
- Toronto Hydro wishes to sell this property and consequently all communication infrastructure has to be removed and relocated with no loss of service during the transition.
- The most feasible course of action is to relocate the copper and fibre cable plus associated terminating and multiplexing equipment to various nearby sites. Among the likely locations are 14 Carlton St., the head office for Toronto Hydro, as well as High Level, Charles and Glengrove Terminal Stations.

- At the same time the existing copper and fibre networks will be redesigned to minimize maintenance costs, enhance network security and provide for optimized and orderly future expansion.

Deferral of this project will increase the cost of acquiring new facilities, increase the risk of a prolonged loss of SCADA services in the case of a vault or cable chamber fire in the vicinity of 60 Eglinton and divert resources to copper cable maintenance instead of improving the fibre optic network throughout the city.

Alternatives

- Relocating all equipment and cables to Duplex Terminal Station, 70 metres north of 60 Eglinton is the simplest alternative however this solution does not provide any optimization or security improvement to the communication networks.
- Space in Duplex Terminal Station is limited and having a large quantity of communication infrastructure in a single Terminal Station location is not recommended from a security standpoint.

Results:

- The copper telephone cable network will be optimized. By taking account of the existing fibre optic network and available interconnection points, the copper network can be redesigned with the result being shorter lengths of copper cable and an improvement in reliability and a decrease in long-term maintenance costs.
- The security and availability of the fibre optic SONET network will be enhanced. This will be done by eliminating portions of the network where redundancy was compromised in the past by not having sufficient physical separation between cables.
- Elimination of financial risk caused by damage to property and livelihood.
- This work will enable Toronto Hydro to undertake other system refurbishment and expansion projects in the future with the knowledge that adequate high speed

communication infrastructure is in place to maximize the use of modern substation automation equipment.

REACTIVE WORK

Table 7: Reactive Work Projects

Project Number	Project Title	Estimated Cost ($)
C09121	Capital Replacement of Overhead Equipment - East	2,296,000
C09122	Capital Replacement of Overhead Equipment - West	4,189,000
C09126	Capital Replacement of Underground Equipment - West	3,302,000
C09127	Capital Replacement of Underground Equipment – East	4,689,000
Overall Cost		14,476,000

PROJECT#: C09121

Business Case Summary

Project Title: Capital Replacement of Overhead Equipment - East

Estimated Cost: $2,296,000

Portfolio: Overhead

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated overhead equipment replacement is performed for the east portion of the city. For the most part, no engineering or design is required.

Description:

- This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.
- Equipment replacement is required right away in order to address the following issues:
    - Customer complaints due to extended outages
    - Potential poor system reliability performance due to increased stress on nearby assets
    - Potential public safety concerns

- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C09122

Business Case Summary

Project Title: Capital Replacement of Overhead Equipment - West

Estimated Cost: $4,189,000

Portfolio: Overhead

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated overhead equipment replacement is performed for the west portion of the city. For the most part, no engineering or design is required.

Description:

- This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.
- Equipment replacement is required right away in order to address the following issues:
    - Customer complaints due to extended outages
    - Potential poor system reliability performance due to increased stress on nearby assets
    - Potential public safety concerns

- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C09126

Business Case Summary

Project Title: Capital Replacement of Underground Equipment - West

Estimated Cost: $3,302,000

Portfolio: Underground Rehabilitation

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated underground equipment replacement is performed for the west portion of the city. For the most part, no engineering or design is required.

Description:

- This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.
- Equipment replacement is required right away in order to address the following issues:
    - Customer complaints due to extended outages
    - Potential poor system reliability performance due to increased stress on nearby assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C09127

Business Case Summary

Project Title: Capital Replacement of Underground Equipment – East

Estimated Cost: $4,689,000

Portfolio: Underground Rehabilitation

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated underground equipment replacement is performed for the east portion of the city. For the most part, no engineering or design is required.

Description:

- This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.
- In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.
- Equipment replacement is required right away in order to address the following issues:
    - Customer complaints due to extended outages
    - Potential poor system reliability performance due to increased stress on nearby assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECTS $500K AND OVER FOR 2010

UNDERGROUND – DIRECT BURIED

Table 1: Underground – Direct Buried Projects

Project Number	Project Title	Estimated Cost ($)
E10051	Curlew - Appleway Townhomes 53M6	990,000
E10006	Bluffwood - Saddletree Area 51M3	1,870,000
E10007	Bellamy Gate Subdivision AE-F3	1,540,000
E10008	Whitehall Subdivision - Feeder PJ-F2	550,000
E10009	Warden OHROW to Steeles Avenue - Feeders 502M28 and 502M21	1,190,000
E10010	Melford feeder NAR26M31	6,050,000
E10011	Glamorgan - Dundalk - Antrim - Feeder NAE51M29	4,400,000
E10012	Fred Bland, 175 Trudelle NA52M5	1,760,000
E10013	Bonacres Subdivision - Feeder PJ-F2	1,320,000
E10014	371 Orton Park Townhomes NAH9M22	880,000
E10015	21, 41, 55 Collinsgrove NA47M15	1,540,000
E10016	Vax, Dutch Myrtleway Townhomes 53M10	880,000
E10017	Thimble Berry Townhomes 51M27	990,000
E10018	Brimley (Brimwood to Steeles) NT63M4 and NT63M12	1,260,000
E10019	Zircon, Francine, McNicoll, Michael 51M27	3,300,000
E10020	Birchmount (OHROW to Steeles) NA502M21, NA502M22	1,190,000
E10021	McCowan (Sandhurst to Steeles) NT63M12	1,120,000
E10037	Harward Sub UG Replacement SA-F1	770,000
E10038	Bayview Mills UG Replacement SS27-F2 and F3	3,300,000
E10039	Paul Markway Townhomes 51M27	530,000
E10040	Ambassador Sub UG Replacement FK-F1	2,220,000

Project Number	Project Title	Estimated Cost ($)
E10041	Tarbert-Bestview-Laureleaf Area UG Replacement SS68-F4	2,310,000
E10042	Linkwood-Golfway Townhouses UG Replacement SS53-F5	550,000
E10043	Mornelle Crt UG Replacement NT47M8	770,000
E10044	Spire, Yellow, Hillway Townhomes UG Replacement 51M27	1,320,000
E10046	Invergordon Subdivision UG Replacement NAH9M26	1,540,000
E10047	Tapscott Industrial Subdivision UG Replacement NAR26M34	2,400,000
E10048	Havendale Sub UG Replacement SG-F3	880,000
E10049	321-357 Trudelle UG Replacement (VC) AE-F1	990,000
E10050	67 Blackwell - Coxworth UG Replacement NAR26M34	1,320,000
W10015	Underground rehabilitation of direct buried cable for feeder SS55F1 in Driftwood/Venetian area	3,510,000
W10016	Underground rehabilitation of direct buried cable for feeder in Steeles/Hilda area	603,600
W10017	Underground rehabilitation of direct buried cable for feeder # 55M25 in the John Cabotway area	500,600
W10018	Underground rehabilitation of direct buried cable for feeder in the Black Hawkway area	1,250,000
W10019	Underground rehabilitation of direct buried cable for feeder # 80M8 in the Ivan Nelson area	1,720,000
Overall Cost		**57,314,200**

PROJECT #: E10051

Business Case Summary

Project Title: E10051 Curlew – Appleway Townhomes 53M6

Estimated Cost: $990,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 53M6
- To rebuild to modern standards the subdivisions bounded by Lawrence, Victoria Park, DVP, and York Mills

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the Asset Condition Assessment ("ACA"), there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree

retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10006

Business Case Summary

Project Title: E10006 Bluffwood – Saddletree Area 51M3

Estimated Cost: $1,870,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 51M3.
- To rebuild to modern standards the subdivisions bounded by Bayview, Leslie, Steeles, and Cummer

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.

- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10007

Business Case Summary

Project Title: E10007 Bellamy Gate Subdivision AE-F3

Estimated Cost: $1,540,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder AE-F3
- To rebuild to modern standards the subdivisions bounded by Lawrence, Bellamy, McCowan, and Lawrence

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10008

Business Case Summary

Project Title: E10008 Whitehall Subdivision – Feeder PJ-F2

Estimated Cost: $550,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder PJ-F2
- To rebuild to modern standards the subdivisions bounded by Lawrence, Morrish, Meadowvale, Colonel Danforth

Description:

- Over the last two years, unplanned outages on this feeder have contributed to almost 110,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 1,500.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10009

Business Case Summary

Project Title: E10009 Warden (OHROW to Steeles Avenue) – Feeders 502M28 and 502M21

Estimated Cost: $1,190,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 502M28 and 502M21
- To rebuild to modern standards the subdivisions Pharmacy, Birchmount, OHROW, and Steeles

Description:

- Over the last two years, unplanned outages on these two feeders have contributed to almost 1,000,000 total customer minutes out. The total number of customer interruptions during the outages was over 12,500
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10010

Business Case Summary

Project Title: E10010 Melford feeder NAR26M31

Estimated Cost: $6,050,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAR26M31
- To rebuild to modern standards the subdivisions by Tapscott, Neilson, OHROW, and Finch

Description:

- Over the last two years, unplanned outages on this feeder have contributed to almost 100,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 3,800
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10011

Business Case Summary

Project Title: E10011 Glamorgan – Dundalk – Antrim - Feeder NAE51M29

Estimated Cost: $4,400,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAE51M29
- To rebuild to modern standards the subdivisions by Birchmount, Kennedy, HWY401, and Ellesmere.

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10012

Business Case Summary

Project Title: E10012 Fred Bland, 175 Trudelle NA52M5

Estimated Cost: $1,760,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA52M5
- To rebuild to modern standards the subdivisions by Lawrence, Bellamy, McCowan, and Eglinton

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10013

Business Case Summary

Project Title: E10013 Bonacres Subdivision – Feeder PJ-F2

Estimated Cost: $1,320,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder PJ-F2
- To rebuild to modern standards the subdivisions bounded by Lawrence, Morrish, Meadowvale, Colonel Danforth

Description:

- Over the last two years, unplanned outages on this feeder have contributed to almost 110,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 1,500.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10014

Business Case Summary

Project Title: E10014 371 Orton Park Townhomes NAH9M22

Estimated Cost: $880,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAH9M22
- To rebuild to modern standards the subdivisions by Ellesmere, Orton Park, Scarborough Golf Club Road.

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10015

Business Case Summary

Project Title: E10015 21, 41, 55 Collinsgrove NA47M15

Estimated Cost: $1,540,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NA47M15
- To rebuild to modern standards the subdivisions by Kingston, Lawrence, West Hill

Description:

- Over the last two years, unplanned outages on this feeder have contributed to over 1,200,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 26,650
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10016

Business Case Summary

Project Title: E10016 Vax, Dutch Myrtleway Townhomes 53M10

Estimated Cost: $880,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 53M10
- To rebuild to modern standards the subdivisions by Don Mills, Lawrence, CNR Railway

Description:

- Over the last two years, unplanned outages on this feeder have contributed to over 100,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 2,700
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10017

Business Case Summary

Project Title: E10017 Thimble Berry Townhomes 51M27

Estimated Cost: $990,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 51M27.
- To rebuild to modern standards the subdivisions by Steeles, Leslie, Don Mills, Duncan Creek River

Description:

- Over the last two years, unplanned outages on this feeder have contributed to over 220,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 1,600
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10018

Business Case Summary

Project Title: E10018 Brimley (Brimwood to Steeles) NT63M4 and NT63M12

Estimated Cost: $1,260,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT63M4 and NT63M12
- To rebuild to modern standards the subdivisions by Midland, McCowan, Brimwood, and Steeles

Description:

- Over the last two years, unplanned outages on these two feeders have contributed to over 6,000,000 total customer minutes out. The total number of customer interruptions during the outages was almost 90,000
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10019

Business Case Summary

Project Title: E10019 Zircon, Francine, McNicoll, Michael 51M27

Estimated Cost: $3,300,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 51M27.
- To rebuild to modern standards the subdivisions by Steeles, Leslie, Don Mills, Duncan Creek River

Description:

- Over the last two years, unplanned outages on this feeder have contributed to over 220,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 1,600
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10020

Business Case Summary

Project Title: E10020 Birchmount (OHROW to Steeles) NA502M21, NA502M22

Estimated Cost: $1,190,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeders NA502M21 and NA502M22
- To rebuild to modern standards the subdivisions by Warden, Kennedy, OHROW, Steeles

Description:

- Over the last two years, unplanned outages on these two feeders have contributed to almost 2,000,000 total customer minutes out. The total number of customer interruptions during the outages was almost 24,000
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10021

Business Case Summary

Project Title: E10021 McCowan (Sandhurst to Steeles) NT63M12

Estimated Cost: $1,120,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT63M12
- To rebuild to modern standards the subdivisions by Brimley, Midland, Sandhurst, and Steeles

Description:

- Over the last two years, unplanned outages on this feeder have contributed to over 4,000,000 total customer minutes out. The total number of customer interruptions during the outages was approximately 4,800
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- Furthermore, the target areas will be redesigned in such a way that the number of customers experiencing potential outages will be greatly reduced. This will be accomplished by eliminating highly unreliable fault interrupters installed almost 20 years ago. These fault interrupters are used within the scope of this project. The combination of failing fault interrupters and failing direct buried XLPE cables caused long outage durations during the last five years.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10037

Business Case Summary

Project Title: E10037 Harward Sub UG Replacement SA-F1

Estimated Cost: $770,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SA-F1.
- To rebuild to modern standards the subdivisions on Harward Subdivision.

Description:

- There has been an average of one unplanned outage per year in this area over the past six years. These outages have contributed to almost 40,000 total customer minutes out. The total number of customer interruptions during the outage was approximately 425.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10038

Business Case Summary

Project Title: E10038 Bayview Mills UG Replacement SS27-F2 and F3

Estimated Cost: $3,300,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SS27-F2 and F3.
- To rebuild to modern standards the subdivisions on Bayview Mills Subdivision.

Description:

- There has been an average of 3.5 unplanned outages per year in this area over the past six years. These outages have been unusually long duration outages contributing to almost 50,000 total customer minutes out. The total number of customer interruptions during the outage was approximately 300.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in

further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.

- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10039

Business Case Summary

Project Title: E10039 Paul Markway Townhomes 51M27

Estimated Cost: $530,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 51M27.
- To rebuild to modern standards the subdivisions on Paul Markway Townhomes.

Description:

- There has been an average of approximately five unplanned outages per year in this area over the past six years.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree

retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased

- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10040

Business Case Summary

Project Title: E10040 Ambassador Sub UG Replacement FK-F1

Estimated Cost: $2,220,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder FK-F1.
- To rebuild to modern standards the subdivisions on Ambassador Subdivision.

Description:

- There has been an average of two unplanned outages per year in this area over the past six years. These outages have contributed to over 7,500 total customer minutes out.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.

- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10041

Business Case Summary

Project Title: E10041 Tarbert-Bestview-Laureleaf Area UG Replacement SS68-F4

Estimated Cost: $2,310,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SS68-F4.
- To rebuild to modern standards the subdivisions on Tarbert-Bestview-Laureleaf Area.

Description:

- There has been an average of six unplanned outages per year in this area over the past six years.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.

- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10042

Business Case Summary

Project Title: E10042 Linkwood-Golfway Townhouses UG Replacement SS53-F5

Estimated Cost: $550,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SS53-F5.
- To rebuild to modern standards the distribution to Linkwood-Golfway Townhouses.

Description:

- There has been an average of eight unplanned outages per year on the feeder over the past six years. These outages have been unusually long duration outages contributing to almost 110,000 total customer minutes out. The total number of customer interruptions during the outage was approximately 2,000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10043

Business Case Summary

Project Title: E10043 Mornelle Crt UG Replacement NT47M8

Estimated Cost: $770,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NT47M8.
- To rebuild to modern standards the distribution to Mornelle Crt Subdivision

Description:

- There has been an average of 7.7 unplanned outages per year on the feeder over the past six years. These outages have been unusually long duration – yearly outages contributing to over 250,000 total customer minutes out. The total number of customer interruptions during the average outage was approximately 14,000.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10044

Business Case Summary

Project Title: E10044 Spire, Yellow, Hillway Townhomes UG Replacement 51M27

Estimated Cost: $1,320,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder 51M27.
- To rebuild to modern standards the distribution to Spire, Yellow, Hillway Townhomes.

Description:

- There has been an average of five unplanned outages per year on this feeder over the past six years.
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing.
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.

- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10046

Business Case Summary

Project Title: E10046 Invergordon Subdivision UG Replacement NAH9M26

Estimated Cost: $1,540,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAH9M26.
- To rebuild to modern standards the distribution to Invergordon Subdivision

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood

- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10047

Business Case Summary

Project Title: E10047 Tapscott Industrial Subdivision UG Replacement NAR26M34

Estimated Cost: $2,400,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAR26M34.
- To rebuild to modern standards the distribution to Tapscott Industrial Subdivision (Melham Ct, Melford Dr, Tapscott Rd).

Description:

- There has been an average of six unplanned outages per year on the feeder over the past six years. These outages have been unusually long duration – yearly outages contributing to over 180,000 total customer minutes out. The total number of customer interruptions during the average outage was approximately 2,700
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and

continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10048

Business Case Summary

Project Title: E10048 Havendale Sub UG Replacement SG-F3

Estimated Cost: $880,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder SG-F3.
- To rebuild to modern standards the distribution to Havendale subdivision (Stainforth Dr and Seaburn pl).

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets

- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10049

Business Case Summary

Project Title: E10049 321-357 Trudelle UG Replacement (VC) AE-F1

Estimated Cost: $990,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder AE-F1 (E51M5).
- To rebuild to modern standards the distribution to Townhomes on 321-357 Trudelle.

Description:

- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water

migration controls that have further reduced the rate of deterioration from treeing

- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets

- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10050

Business Case Summary

Project Title: E10050 67 Blackwell – Coxworth UG Replacement NAR26M34

Estimated Cost: $1,320,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To address the end-of-life condition of failing old XLPE direct buried primary cable.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeder NAR26M34.
- To rebuild to modern standards the distribution to 67 Blackwell – Coxworth Cr.

Description:

- There has been an average of six unplanned outages per year on the feeder over the past six years. These outages have been unusually long duration – yearly outages contributing to over 180,000 total customer minutes out. The total number of customer interruptions during the average outage was approximately 2,700
- The distribution system was built in the seventies as an underground distribution system, with direct buried primary and secondary cables and submersible transformer vaults. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued

repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.

- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.
- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W10015

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder SS55F1 in Driftwood/Venetian area

Estimated Cost: $ 3,510,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Driftwood/Venetian area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better

protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second

contingency scenarios

PROJECT #: W10016

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder in Steeles/Hilda area

Estimated Cost: $603,600

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Steeles/Hilda area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing.
- The areas will be rebuilt using concrete encased ducts in order to provide better

protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood

- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: W10017

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder # 55M25 in the John Cabotway area

Estimated Cost: $ $500,600

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the John Cabotway area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better

protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second

contingency scenarios

PROJECT #: W10018

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder in the Black Hawkway area

Estimated Cost: $ 1,250,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Black Hawkway area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better

protection for the cable as well as reducing costs and outage duration during future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second

contingency scenarios

PROJECT #: W10019

Business Case Summary

Project Title: Underground rehabilitation of direct buried cable for feeder # 80M8 in the Ivan Nelson area

Estimated Cost: $1,720,000

Portfolio: Underground Rehabilitation – Direct Buried

Objective:

- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address the end-of-life condition of direct buried cable in the Ivan Nelson area

Description:

- The distribution system was built in the sixties as an underground distribution system, with direct buried primary cables. Every fault in the past has overstressed the insulation and as evidenced in the ACA, there is a necessity for replacement in this area.
- In the past several years, the distribution system components (cables, elbows and transformers) have been failing at an abnormal rate with extended outages.
- It was determined that the condition of these cables is not likely to improve and continued repair will become a costly and unreliable alternative. Also continued repair of direct buried cable disturbs the earth of localized cable resulting in further negative impacts.
- This project will replace the old, unreliable direct buried XLPE cable with tree retardant XLPE cables that incorporate designs with metal foil barriers and water migration controls that have further reduced the rate of deterioration from treeing
- The areas will be rebuilt using concrete encased ducts in order to provide better protection for the cable as well as reducing costs and outage duration during

future repairs. Repair of direct buried cable entails trenching, ground movements, uncertainty around locates, landscaping repairs to roads, sidewalk, boulevard, private property, traffic congestion, and potential public hazards.

- In conjunction with the installation of new concrete encased primary distribution, consideration is also given to replace other aging assets such as transformers, elbows, and other assets in order to take advantage of economies of scale and to minimize public disturbances in the future. Consideration is also given to pad-mounted switch replacements in the target area due to their recent history of failures and poor condition as illustrated in the ACA.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

UNDERGROUND REHAB

Table 2: Underground Rehab Projects

Project Number	Project Title	Estimated Cost ($)
DC_E10024	Permanent Cut Repair Restoration – East	1,200,000
DC_E10025	System Enhancement: Underground Cable Rehabilitation – East	1,454,600
DC_W10027	System Enhancement: Underground Cable Rehabilitation – West	1,455,000
DC_W10029	Permanent City Cut Restoration – West	800,000
E10030	Design for 2011 Projects – Distribution Projects East	1,200,800
W10054	Design for 2011 Projects – Distribution Projects West	1,800,000
W10012	W10012 Load Transfer – Transfer Dufferin Feeders A-273-310-530-DN to Wiltshire TS	600,000
W10013	Rear Lot – Underground conversion 4 kV to 27.6 kV: Forest Hill area – Phase 3	3,000,000
W10083	W10083 Duplex Feeder Leakers UG repl	793,968
W10084	W10084 Dufferin Feeder Leakers UG repl	834,162
E10093	E10093 Rear Lot E5-3	600,000
Overall Cost		**13,738,530**

PROJECT #: DC_E10024

Business Case Summary

Project Title: Permanent Cut Repair Restoration – East

Estimated Cost: $1,200,000

Portfolio: Underground Rehabilitation

Objective:

To compensate the City of Toronto for costs they incur to permanently repair city infrastructure such as roads, sidewalks and boulevards in the east portion of the city.

Description:

In the process of undertaking (usually) underground construction work, THESL is required to break into existing City of Toronto infrastructure such as roads, sidewalks, and boulevards. Once the THESL work is completed, the City of Toronto's contractors repair/restore the damaged infrastructure. All efforts are made between THESL, the City of Toronto, and a number of other utilities to avoid conflict of schedules. Furthermore, co-ordination is made in order to facilitate efficiencies such as the agreement between utilities of joint-use trenches.

Timely cut-repairs are required right away in order to address the following issues:

- Customer complaints due to unsightly landscape
- Potential public safety hazards
- Exposure to further financial risk

Deferral of this project would unduly prolong the presence of fenced construction areas. This would impede the flow of pedestrian and vehicular traffic in the area concerned. Deferral will also lead to non-compliance with established City of Toronto regulations

Results:

- Compliance with City of Toronto regulations
- Improved public safety
- Mitigation of financial risk

IP REFERENCE #: DC_E10025

Business Case Summary

Project Title: System Enhancement: Underground Cable Rehabilitation – East

Estimated Cost: $1,454,600

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of unplanned capital investments related to underground assets in the east portion of the city. For the most part, engineering and design is required
- To resolve unplanned underground infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to underground assets.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address defective underground plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as cable chambers, vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W10027

Business Case Summary

Project Title: System Enhancement: Underground Cable Rehabilitation – West

Estimated Cost: $1,455,000

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of unplanned capital investments related to underground assets in the west portion of the city. For the most part, engineering and design is required
- To resolve unplanned underground infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to underground assets.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address defective underground plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as cable chambers, vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W10029

Business Case Summary

Project Title: Permanent City Cut Restoration – West

Estimated Cost: $800,000

Portfolio: Underground Rehabilitation

Objective:

To compensate the City of Toronto for costs they incur to permanently repair city infrastructure such as roads, sidewalks and boulevards in the west portion of the city.

Description:

In the process of undertaking (usually) underground construction work, THESL is required to break into existing City of Toronto infrastructure such as roads, sidewalks, and boulevards. Once the THESL work is completed, the City of Toronto's contractors repair/restore the damaged infrastructure. All efforts are made between THESL, the City of Toronto, and a number of other utilities to avoid conflict of schedules. Furthermore, co-ordination is made in order to facilitate efficiencies such as the agreement between utilities of joint-use trenches.

Timely cut-repairs are required right away in order to address the following issues:

- Customer complaints due to unsightly landscape
- Potential public safety hazards
- Exposure to further financial risk

Deferral of this project would unduly prolong the presence of fenced construction areas. This would impede the flow of pedestrian and vehicular traffic in the area concerned. Deferral will also lead to non-compliance with established City of Toronto regulations

Results:

- Compliance with City of Toronto regulations
- Improved public safety
- Mitigation of financial risk

PROJECT #: E10030

Business Case Summary

Project Title: Design for 2011 Projects – Distribution Projects East

Estimated Cost: $1,200,800

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of designing projects for construction in 2011. These designs encompass distribution projects located in the east portion of the city.

Description:

- The designer will use the issued project documentation for work coordinated between East Construction and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Designing include:
  - Create drawings and specifications
  - Field work
  - Prepare bill of materials and order material and equipment.
  - Prepare detailed estimate
  - Arrange for work permits pursuant to provincial and federal legislation
  - Send projects out for construction.
  - Administer civil contracts
- Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns
- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Optimal resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: W10054

Business Case Summary

Project Title: Design for 2011 Projects – Distribution Projects West

Estimated Cost: $1,800,000

Portfolio: Underground Rehabilitation

Objective:

- To cover the cost of designing projects for construction in 2011. These designs encompass distribution projects located in the east portion of the city.

Description:

- The designer will use the issued project documentation for work coordinated between West Construction and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Designing include:
  - Create drawings and specifications
  - Field work
  - Prepare bill of materials and order material and equipment.
  - Prepare detailed estimate
  - Arrange for work permits pursuant to provincial and federal legislation
  - Send projects out for construction.
  - Administer civil contracts
- Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns
- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Efficient resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

PROJECT #: W10012

Business Case Summary

Project Title: W10012 Load Transfer – Transfer Dufferin Feeders A-273-310-530-DN to Wiltshire TS

Estimated Cost: $600,000

Portfolio: Underground Rehabilitation

Objective:

- Wilshire TS has recently been converted to 4-wire system. The Dufferin Feeders A-273-310-530 feed the load which is geographically in Wiltshire area.
- Dufferin TS being closer to downtown area need spare capacity for local area.
- To improve feeder reliability by reducing length of feeders.

Description:

- Extend the duct structure as required to transfer the Dufferin Feeders A-273-310-530 to Wiltshire TS

Deferral of this work will result in continued reduction of system reliability, and increased customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

PROJECT #: W10013

Business Case Summary

Project Title: Rear Lot – Underground conversion 4 kV to 27.6 kV: Forest Hill area – Phase 3

Estimated Cost: $3,000,000

Portfolio: Underground Rehabilitation

Objective:

- To relocate primary and secondary rear fed distribution to front lot underground
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address age and difficulty for accessing Toronto Hydro owned equipment

Description:

- To address deteriorating rear lot distribution in the Forest Hill area bounded by Bathurst Street, Briar Hill, Allen Express Way and RidelleAvenue.
- To convert the 4 kV distribution in the rear to 27.6kV underground distribution in the front using feeder 35M6 on Bathurst St.
- This project has been selected based on criteria used to prioritize rear lot plants
- The criteria used are:
    - Plant age
    - Number of customers
    - Primary voltage
    - Adjacent area's primary voltage
    - Adjacent area's construction type
    - Tree density
    - Customer satisfaction

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in negative customer impacts as well as increased maintenance costs. Potential very long outages would be probable

Results:

- Reduced maintenance costs over the immediate term
- Improvements in servicing by THESL field crews
- Improve reliability
- Safer distribution system
- Easy accessibility for crews and less disruption to customers

PROJECT #: W10083

Business Case Summary

Project Title: W10083 Duplex Feeder Leakers UG repl

Estimated Cost: $793,968

Portfolio: Underground Rehabilitation

Objective:

- To address the leaking condition of PILC cables, joints and potheads and remove the Raychem patches,
- To prevent potential emergency situations that cause high restoration costs and overload conditions,
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeders out of Duplex (DX) station.

Description:

- The quantity of cable leakers has increased over the last decade. This scenario is susceptible to instances where costs could substantially increase when restorations are required during an emergency scenario. Furthermore, during such instances, cables would likely be subjected to potentially damaging overload conditions.
- Based on the last years leaker database there are presently 51 leaking items on feeders out of Duplex station – items of 25 cable, 17 sleeve, 6 pothead replacement, and 3 patches.
- The Underground Environmental Health and Safety ("UGEH&S") Committee suggested (minute #UG-003) to allocate enough funds to reduce the quantity of leakers presently within the system.
- UGEH&S Committee (minute #UG-167) also treats any Raychem Heat Shrink patches used on cables as a temporary measure to stop a leak and recommends

replacing it as early as possible.

- Asset Management has decided to initiate a planned leaker repair program that will address all the outstanding leakers. The investment in the first few years will be directed to address the feeders in areas or out of substations where presence of leakers are found in concentrated numbers.
- This project will repair/replace all leaking cables/splices, potheads and remove all existing Raychem Heat Shrink patches within the vicinity of Duplex (W) station. This investment will prevent potential emergency situations that cause high restoration costs and overload conditions, therefore improving system sustainability.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, increased risk of fire hazard and customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Full functionality of the Primary assets will be restored.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second

contingency scenarios

Project #: W10084

Business Case Summary

Project Title: W10084 Dufferin Feeder Leakers UG repl

Estimated Cost: $834,162

Portfolio: Underground Rehabilitation

Objective:

- To address the leaking condition of PILC cables, joints and potheads and remove the Raychem patches,
- To prevent potential emergency situations that cause high restoration costs and overload conditions,
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To improve the reliability of feeders out of Dufferin (DN) station.

Description:

- The quantity of cable leakers has increased over the last decade. This scenario is susceptible to instances where costs could substantially increase when restorations are required during an emergency scenario. Furthermore, during such instances, cables would likely be subjected to potentially damaging overload conditions.
- Based on the last years leaker database there are presently 58 leaking items on feeders out of Dufferin station – items of 25 cable, 18 sleeve, seven pothead replacement, six patches and two piece outs.
- The UGEH&S Committee suggested (minute #UG-003) to allocate enough funds to reduce the quantity of leakers presently within the system.
- UGEH&S Committee (minute #UG-167) also treats any Raychem Heat Shrink patches used on cables as a temporary measure to stop a leak and recommends replacing it as early as possible.

- Asset Management has decided to initiate a planned leaker repair program that will address all the outstanding leakers. The investment in the first few years will be directed to address the feeders in areas or out of substations where presence of leakers are found in concentrated numbers.
- This project will repair/replace all leaking cables/splices, potheads and remove all existing Raychem Heat Shrink patches within the vicinity of Dufferin (W) station. This investment will prevent potential emergency situations that cause high restoration costs and overload conditions, therefore improving system sustainability.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction of system reliability, increased risk of fire hazard and customer complaints due to extended and frequent outages. Also, deferral will result in continued stress to other associated assets.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Full functionality of the Primary assets will be restored.
- Customer satisfaction increased
- Reduction to stressed assets
- Elimination of financial risk caused by damage to property and livelihood
- Improvement to grid operating conditions; i.e., avoided potential second contingency scenarios

PROJECT #: E10093

Business Case Summary

Project Title: E10093 Rear Lot E5-3

Estimated Cost: $600,000

Portfolio: Underground Rehabilitation

Objective:

- To relocate primary and secondary rear fed distribution to front lot overhead
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address age and difficulty for accessing THESL-owned equipment

Description:

- This project has been selected based on criteria used to prioritize rear lot plants
- The criteria used are:
    - Plant age
    - Number of customers
    - Primary voltage
    - Adjacent area's primary voltage
    - Adjacent area's construction type
    - Tree density
    - Customer satisfaction

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as

Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in continued repeat service calls for localized outages with associated Customer service degradation and eventual widespread outages and escalating operating costs

Alternatives:

- A number of alternatives were analyzed and compared. The only cost and safety feasible alternative was this changeover permitting long run improvements in the way electrical services can be provided and maintained in this area.

Results:

- Reduced maintenance costs over the immediate term
- Improvements in servicing by THESL field crews
- Improve reliability
- Safer distribution system
- Easy accessibility for crews and less disruption to customers

OVERHEAD

Table 3: Overhead Projects

Project Number	Project Title	Estimated Cost ($)
DC_E10026	System Enhancement: Overhead Rehabilitation – East	518,000
DC_W10028	System Enhancement: Overhead Rehabilitation – West	518,000
E08050	Overhead rehabilitation – installation of new 27.6kV SCADA switches in former North York area	1,520,000
E10031	Equipment Nomenclature Enhancement – East	1,900,000
W4191	Voltage Conversion of 4 kV Horsham Feeder SS60F3 OH REHAB	
W07111	Voltage Conversion of W07111 Sunnyside_Grden B-10-J OH VC Ph #2	550,000
W09099	Overhead rehabilitation – installation of new 27.6kV SCADA switches in former North York area	1,200,000
W10011	Voltage Conversion 4 kV Wiltshire Feeder B-3-5-W VC to 13.8 kV	2,500,000
W10014	Voltage Conversion of Overhead 4 kV Sunnyside Garden Feeder B-10-J Ph #2	600,000
Overall Cost		11,909,463

IP REFERENCE #: DC_E10026

Business Case Summary

Project Title: System Enhancement: Overhead Rehabilitation – East

Estimated Cost: $518,000

Portfolio: Overhead

Objective:

- To cover the cost of unplanned capital investments related to overhead assets in the east portion of the city. For the most part, engineering and design is required
- To resolve unplanned overhead infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to overhead assets.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address defective overhead plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work

prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

IP REFERENCE #: DC_W10028

Business Case Summary

Project Title: System Enhancement: Overhead Rehabilitation – West

Estimated Cost: $518,000

Portfolio: Overhead

Objective:

- To cover the cost of unplanned capital investments related to overhead assets in the west portion of the city. For the most part, engineering and design is required
- To resolve unplanned overhead infrastructure conflict with the external agencies such as the City of Toronto, Bell, and Enbridge
- To address unexpected customer complaints due to the lack of reliable performance related to overhead assets.
- To improve upon the worsening SAIFI trend over the last five years due to equipment related outages
- To address defective overhead plant that poses unforeseen significant risk to system reliability.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In determining the relative potential value of performing a particular project, the work

prioritization process is followed. Also, new plant is installed with consideration given to capacity planning, improved modernized equipment, improvements to long term reliability improvement, and customer satisfaction.

Equipment replacement is required in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets
- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: E08050

Business Case Summary

Project Title: Overhead rehabilitation – installation of new 27.6kV SCADA switches in former North York area

Estimated Cost: $1,520,000

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI.
- To improve substandard communication for existing remote switches.

Description:

- Replace 16 switch locations of old remote switches and three manual switches using the new wireless communication system and new SCADA operated switches in North York area.
- Existing switches are aging and have non-standard communication components
- Existing switches have old and non-reliable battery and charger
- Existing failing radio system that has potential to disable remaining radio communication
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- Spare parts for existing equipment difficult to attain
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location should is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- This project will improve reliability to all feeders associated with Scarborough TS located in the east portion of the city

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction in reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- End of Life replacement for old assets within the remote switch class
- The spare parts issue is considerably improved
- The new RTUs are “Feeder Automation” ready (should THESL decide to pursue this initiative)

IP REFERENCE #: E10031

Business Case Summary

Project Title: Equipment Nomenclature Enhancement – East

Estimated Cost: $1,900,000

Portfolio: Overhead

Objective:

- To re-label all the operable distribution devices across the distribution system according to a new consistent nomenclature standard.

Description:

- There are six legacy location identification approaches across the distribution system, some of which vary immensely from the others. This creates potential confusion to crews that may not be familiar with these standards and could pose operational hazards.
- In order to eliminate the potential hazards of improper operation, there is a need to harmonize the nomenclature. All devices need to be relabelled according to the new nomenclature standard.
- The new nomenclature also supports the new DMS System in Operation.
- In certain locations, THESL personnel are required to isolate the asset to be labelled. This requires a set of switching procedures to be followed according to THESL's work protect code
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

Deferral or failure to address these deficiencies could lead to inappropriate operation of equipment in the field.

Results:

- Elimination of financial risk caused by damage to property and livelihood
- Mitigation of hazards to THESL personnel and public

IP REFERENCE #: W10103

Business Case Summary

Project Title: Equipment Nomenclature Enhancement – West

Estimated Cost: $1,900,000

Portfolio: Overhead

Objective:

- To re-label all the operable distribution devices across the distribution system according to a new consistent nomenclature standard.

Description:

- There are six legacy location identification approaches across the distribution system, some of which vary immensely from the others. This creates potential confusion to crews that may not be familiar with these standards and could pose operational hazards.
- In order to eliminate the potential hazards of improper operation, there is a need to harmonize the nomenclature. All devices need to be relabelled according to the new nomenclature standard.
- The new nomenclature also supports the new DMS System in Operation.
- In certain locations, THESL personnel are required to isolate the asset to be labelled. This requires a set of switching procedures to be followed according to THESL's work protect code
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

Deferral or failure to address these deficiencies could lead to inappropriate operation of equipment in the field.

Results:

- Elimination of financial risk caused by damage to property and livelihood
- Mitigation of hazards to THESL personnel and public

PROJECT #: W4191

Business Case Summary

Project Title: Voltage Conversion of 4 kV Horsham Feeder SS60F3 OH REHAB

Estimated Cost: $703,463

Portfolio: Overhead

Objective:

- To convert the Churchill MS F3 (SS60-F3) load to 27.6 kV via the Fairchild TS 80M1.
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear

Description:

- Churchill MS F3 has experienced several forced outages in 2000. Churchill F3 is moderately loaded with an actual load of close to 1 MVA. Most of this load is distributed on residential streets adjacent to Senlac Road, and is connected via overhead front lot pole lines. The age of this plant is over 50 years in most areas, and is deteriorating quite noticeably.
- It is proposed to convert the Churchill MS F3 load to 27.6 kV via the Fairchild TS 80M1. As the Fairchild 80M1 supplies the Churchill MS, this conversion will actually result in a very small net drop in load on the Fairchild 80M1.
- This 4 kV distribution system is old and deteriorating.
- To reduce losses and improve the reliability convert this area to 27.6 kV system supplied from the 27.6 kV System.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment

- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Significant improvement to electrical reliability for this area.
- Reduction of system losses

PROJECT #: W07111

Business Case Summary

Project Title: Voltage Conversion of W07111 Sunnyside_Grden B-10-J OH VC Ph #2

Estimated Cost: $ 550,000

Portfolio: Overhead

Objective:

- To convert a the complete 4 kV Sunnyside_Grden B-10-J OH VC Ph #2
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear

Description:

- This 4 kV distribution system is old and deteriorating.
- To reduce losses and improve the reliability convert this area to 13.8 kV system supplied from the 13.8 kV System.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Significant improvement to electrical reliability for this area
- Reduction to system losses

PROJECT #: W09099

Business Case Summary

Project Title: Overhead rehabilitation – installation of new 27.6kV SCADA switches in former North York area

Estimated Cost: $1,200,000

Portfolio: Overhead

Objective:

- To improve system reliability, specifically CMO and CAIDI.
- To improve substandard communication for existing remote switches.

Description:

- Replace 15 switch locations of old remote switches using the new wireless communication system and new SCADA operated switches in North York area.
- Existing switches are aging and have non-standard communication components
- Existing switches have old and non-reliable battery and charger
- Existing failing radio system that has potential to disable remaining radio communication
- Integrate all SCADA switches to one communication system compatible with Telvent, the new SCADA radio control.
- Spare parts for existing equipment difficult to attain
- A scheme consisting of one normally closed and one normally open switch is implemented so that significant potential CMO reduction can be achieved.
- The switch location should is optimized for maximum potential CMO reduction and also takes into account load utilization factors, and critical customers as well.
- This project will improve reliability to all feeders associated with Scarborough TS located in the east portion of the city
- THESL will conduct this work in accordance with the OHSA and associated

regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work will result in continued reduction in reliability, resulting in negative customer impacts.

Results:

- Effectively improve feeder reliability, specifically by reducing duration of outages.
- End of Life replacement for old assets within the remote switch class
- The spare parts issue is considerably improved
- The new RTUs are “Feeder Automation” ready (should THESL decide to pursue this initiative)

PROJECT #: W10011

Business Case Summary

Project Title: Voltage Conversion 4 kV Wiltshire Feeder B-3-5-W VC to 13.8 kV

Estimated Cost: $2,500,000

Portfolio: Overhead

Objective:

- To convert a the complete 4 kV Wiltshire Feeder B-3-5-W VC to 13.8 kV
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear at Wiltshire Station. Moreover the Wiltshire Station needs space to later replace 13.8 kV Switchgear.

Description:

- The 4 kV distribution system from Wiltshire 4 kV switchgear is old and deteriorating.
- To reduce losses and improve the reliability convert this area to 13.8 kV system supplied from the 13.8 kV switchgear at the Wiltshire Station.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Alternatives:

- Various 13.8 kV and 27.6 kV feeders in the nearby area were considered to be brought in this area for voltage conversion.
- The best alternative is to use the 13.8 kV feeders from the Wiltshire Station

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Significant improvement to electrical reliability for this area.
- Reduction of system losses

PROJECT #: W10014

Business Case Summary

Project Title: Voltage Conversion of Overhead 4 kV Sunnyside Garden Feeder B-10-J Ph #2

Estimated Cost: $600,000

Portfolio: Overhead

Objective:

- To convert a the complete 4 kV Sunnyside Garden Feeder B-9-J OH VC PH#1
- This is a part of the project to decommission the aging 4 kV distribution in the area and then ultimately decommission the aging 4 kV switchgear

Description:

- This 4 kV distribution system is old and deteriorating.
- To reduce losses and improve the reliability convert this area to 13.8 kV system supplied from the 13.8 kV System.
- The aging 4 kV distribution will be eliminated through voltage conversion.
- The assets will be replaced on a like-for-like basis with consideration given to modernized equipment
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this work would result in greater deterioration of service reliability, excessive short run maintenance costs, and further customer inconveniences.

Results:

- Feeder reliability will be improved, reducing both outage duration and frequency.
- Primary assets at their end of service life will be replaced.
- Significant improvement to electrical reliability for this area.
- Reduction to system losses

NETWORK

Table 4: Network Projects

Project Number	Project Title	Estimated Cost ($)
E10032	Network Transformer Replacement 25 units	2,500,000
W10034	Network Transformer Replacement 25 units	2,500,000
Overall Cost		5,000,000

PROJECT #: E10032

Business Case Summary

Project Title: Network Transformer Replacement 25 units

Estimated Cost: $2,500,000

Portfolio: Network

Objective:

- To replace 25 network transformers and associated fibre top protectors that are deemed unreliable as a result of past failures.

Description:

- This project is aimed towards the replacement of network transformers and associated fibre top protectors throughout the city.
- Fibre top protectors are vulnerable to salty water. The conductive salty water causes severe corrosion of the electrical connections. Excessive heat could also be generated on the electrical connections of the protector as a result of the salty water and the creation of an arc could cause a fire in the vault. To avoid such risk, it is necessary to replace the fibre top protectors and the associated transformers since new protectors cannot be fitted on the existing old transformers.
- Replace approximately 50 transformers based on condition assessment and prioritize by age of the transformers and replacement of fibre top protectors.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this project will result in further equipment deterioration and eventual failure of transformers and protectors, which will reduce the reliability of the network system.

Catastrophic failure of network transformer could jeopardize public safety as well, so a proactive replacement program is necessary.

Results:

- Safe and reliable power supply to the downtown customers will be secured.
- Safe equipment operation will be achieved.

PROJECT #: W10034

Business Case Summary

Project Title: Network Transformer Replacement 25 units

Estimated Cost: $2,500,000

Portfolio: Network

Objective:

- To replace 25 network transformers and associated fibre top protectors that are deemed unreliable as a result of past failures.

Description:

- This project is aimed towards the replacement of network transformers and associated fibre top protectors throughout the city.
- Fibre top protectors are vulnerable to salty water. The conductive salty water causes severe corrosion of the electrical connections. Excessive heat could also be generated on the electrical connections of the protector as a result of the salty water and the creation of an arc could cause a fire in the vault. To avoid such risk, it is necessary to replace the fibre top protectors and the associated transformers since new protectors cannot be fitted on the existing old transformers.
- Replace approximately 50 transformers based on condition assessment and prioritize by age of the transformers and replacement of fibre top protectors.
- THESL will conduct this work in accordance with the OHSA and associated regulations, the E&USA Rule Book, the Transportation of Dangerous Goods Act, and WSIB requirements. Efforts are made to mitigate any foreseeable hazards which may result in personal injury or environmental concerns. Programs such as Safety by Design, Job Planning, Crew Visits, and Tailboard Meetings are utilized to eliminate or control these hazards.

Deferral of this project will result in further equipment deterioration and eventual failure of transformers and protectors, which will reduce the reliability of the network system.

Catastrophic failure of network transformer could jeopardize public safety as well, so a proactive replacement program is necessary.

Results:

- Safe and reliable power supply to the downtown customers will be secured.
- Safe equipment operation will be achieved.

TRANSFORMER STATION

Table 5: Transformer Station Projects

Project Number	Project Title	Estimated Cost ($)
S10008	Strachan Transformer Station: Replace A3-4T Switchgear	3,145,572
S10009	Wiltshire Transformer Station: Replace A3-4W Switchgear	3,145,572
S10010	Carlaw TS: Replace A4-5E Switchgear	3,145,572
Overall Cost		9,436,716

PROJECT #: S10008

Business Case Summary

Project Title: Strachan Transformer Station: Replace A3-4T Switchgear

Estimated Cost: $ 3,145,572

Portfolio: Transformer Station

Objective:

- To replace the existing A3-4T switchgear at Strachan station

Description:

- The A3-4T switchgear is 54 years old and has reached the end of its service life.
- The existing circuit breakers are of the air blast type and are obsolete. Replacement parts are no longer being manufactured. Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The air blast circuit breakers at this station have additional maintenance costs due to the added expense of renewing and maintaining the air supply system needed for breaker operation.
- The switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure.
- The project involves the replacement of the switchgear with 3000 A air insulated arc-resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with contingencies, increased safety risk and increased operating costs.

Alternatives:

- Replace the switchgear with gas insulated switchgear rather than with air insulated metal clad switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance.
- Improved system reliability and reduced risk.
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time.

PROJECT #: S10009

Business Case Summary

Project Title: Wiltshire Transformer Station: Replace A3-4W Switchgear

Estimated Cost: $ 3,145,572

Portfolio: Transformer Station

Objective:

- To replace the existing A3-4W switchgear at Wiltshire substation to address its end of life condition.

Description:

- The A3-4W switchgear is 53 years old and has approaching the end of its service life.
- The existing circuit breakers are of the air blast type and are obsolete. Replacement parts are no longer being manufactured. Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The air blast circuit breakers at this station have additional maintenance costs due to the added expense of renewing and maintaining the air supply system needed for breaker operation.
- The switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure.
- The project involves the replacement of the switchgear with 3000 A air insulated arc-resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with

contingencies, increased safety risk and increased operating costs.

Alternatives:

- Replace the switchgear with gas insulated switchgear rather than with air insulated switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance
- Improved system reliability and reduced risk
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time

PROJECT#: S10010

Business Case Summary

Project Title: Carlaw TS: Replace A4-5E Switchgear

Estimated Cost: $ 3,145,572

Portfolio: Transformer Station

Objective:

- To replace the A4-5E Switchgear at Carlaw Transformer Station to address end of life condition of the equipment.

Description:

- The A4-5E switchgear is 57 years old and has reached the end of its service life.
- The existing circuit breakers are of the air blast type and are obsolete. Replacement parts are no longer being manufactured. Any parts required need to be custom manufactured, making the cost of maintenance high and the repair and return to service time long.
- The air blast circuit breakers at this station have additional maintenance costs due to the added expense of renewing and maintaining the air supply system needed for breaker operation.
- The basic design of the switchgear, being an open brick structure, is a safety concern to operating personnel of THESL due to the exposed live parts of the switchgear.
- The switchgear is of a non-arc-resistant design and has an increased risk of collateral damage and personnel injury during an eventful failure.
- The project involves the replacement of the switchgear with 3000 A air insulated arc-resistant type switchgear in order to improve equipment performance, system reliability, and personnel safety as well as achieve operating cost reductions.

Deferral of this project will result in further deterioration of the existing aged equipment, decreased performance, decreased system reliability, decreased ability to deal with contingencies, increased safety risk and increased operating costs.

Alternatives:

- Replace the switchgear with gas insulated switchgear rather than with air insulated metal clad switchgear. Due to the availability of floor space, the air insulated switchgear is more cost effective.

Results:

- More reliable equipment performance.
- Improved system reliability and reduced risk.
- Improved personnel safety
- Reduced maintenance costs and decreased maintenance time.

MUNICIPAL SUBSTATION

Table 6: Municipal Substation Projects

Project Number	Project Title	Estimated Cost ($)
S10033	Design for 2011 projects - Stations	700,000
Overall Cost		700,000

PROJECT #: S10033

Business Case Summary

Project Title: Design for 2011 projects - Stations

Estimated Cost: $700,000

Portfolio: Municipal Substation

Objective:

- To cover the cost of stations projects being designed for construction in 2011.

Description:

- The designer will use the issued project documentation for work coordinated between Stations and Asset Management to complete design packages. The designers will provide detailed estimates by applying Standard Design Practice, Bill of Materials, and compatible units within related statutory regulation.
- Designing include:
  - Create drawings and specifications
  - Field work
  - Prepare bill of materials and order material and equipment.
  - Prepare details estimate
  - Arrange for work permits pursuant to provincial and federal legislation
  - Send projects out for construction.
  - Administer civil contracts

Deferral of this work would result in the postponement of all proposed construction projects in the eastern part of the city. Inadequate attention to proper design of projects may lead to the following:

- Inefficient construction
- Public safety concerns

- THESL personnel safety concerns
- Inconsistent construction of assets
- Non-optimal performance of assets with respect to reliability performance

Results:

Upon completion of the design packages, the construction crews can perform the field work resulting in the following:

- Efficient resource balancing
- Enhanced cost-control for projects
- Mitigation of public and THESL personnel safety concerns
- Optimal performance of assets with respect to reliability performance

REACTIVE WORK

Table 7: Reactive Work Projects

Project Number	Project Title	Estimated Cost ($)
C10020	Capital Replacement of Overhead Equipment - West	4,189,000
C10021	Capital Replacement of Overhead Equipment - East	2,296,000
C10022	Capital Replacement of Underground Equipment - East	4,689,000
C10023	Capital Replacement of Underground Equipment - West	3,302,000
Overall Cost		14,476,000

PROJECT #: C10020

Business Case Summary

Project Title: Capital Replacement of Overhead Equipment – West

Estimated Cost: $4,189,000

Portfolio: Overhead

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated overhead equipment replacement is performed for the west portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. T his includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT#: C10021

Business Case Summary

Project Title: Capital Replacement of Overhead Equipment - East

Estimated Cost: $2,296,000

Portfolio: Overhead

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated overhead equipment replacement is performed for the east portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary overhead distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, poles, wire, transformers, and pole-line hardware, such as guying, insulators, and switches. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Weather, animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the overhead system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C10022

Business Case Summary

Project Title: Capital Replacement of Underground Equipment – East

Estimated Cost: $4,689,000

Portfolio: Underground Rehabilitation

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated underground equipment replacement is performed for the east portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

PROJECT #: C10023

Business Case Summary

Project Title: Capital Replacement of Underground Equipment – West

Estimated Cost: $3,302,000

Portfolio: Underground Rehabilitation

Objective:

- The goal of this program is to maintain the reliability of supply.
- Under this project, like-for-like damaged or deteriorated underground equipment replacement is performed for the west portion of the city. For the most part, no engineering or design is required.

Description:

This project replaces primary and secondary underground distribution plant that has been damaged or has deteriorated. This includes, but is not limited to, cables, splices, joints, transformers, switches, and civil infrastructures such as vault doors, grates, ladder-ways and cable racking equipment. Assets addressed within the scope of this project have failed to perform abruptly and have not been considered within the planned capital expenditures. Animals, external contractors/utilities, age, and general deteriorating conditions cause abrupt failures of these assets.

In scheduling resources to correct the grid deficiency, consideration is given to higher priority issues based upon a predetermined criterion weighting system.

Equipment replacement is required right away in order to address the following issues:

- Customer complaints due to extended outages
- Potential poor system reliability performance due to increased stress on nearby assets

- Potential public safety concerns
- Potential environmental concerns
- Potential THESL personnel safety concerns
- Exposure to further financial risk caused by damage to other associated assets
- Maintain operating conditions; i.e., avoid second contingency conditions

Deferral or failure to address these deficiencies and issues promptly would result in the failure of THESL to provide customers with a proper level of reliability. Also, the public would be exposed to potential safety hazards as well. Neglecting the initiatives of this project would be in conflict with established related safety, environmental and regulatory standards.

Results:

- Maintain the underground system in a safe manner
- Maintain flexible operating conditions for the distribution grid
- Maintain overall system reliability at suitable levels
- Mitigate localized customer outage duration

DISTRIBUTION CAPITAL

ASSET CONDITION ASSESSMENT - OBJECTIVE

In 2006, THESL worked with an asset condition consultant, Kinectrics Inc., to conduct a study to assess both the condition, and the management of the condition, of THESL's distribution plant.

The study was based upon 2005 data and the purpose was to detect and quantify long-term degradation of distribution assets and to provide a means of quantifying remaining asset life.

OVERVIEW

The Asset Condition Assessment ("ACA") is a fundamental tool for developing maintenance plans and long-term asset replacement and capital investment plans. Knowledge of the asset condition assists in defining immediate and longer term programs and expenditures to ensure that assets are well managed.

THESL retained the services of Kinectrics Inc., experts on the technical aspects of the distribution utility business and particularly in the subject of condition assessment and Health Indices, to conduct an asset condition assessment and a field audit of asset condition.

The ACA report provides an assessment of THESL's distribution assets condition based on existing available documentation, an audit of the assets, and an estimate of how many assets will require replacement within the next year and the next ten years.

A considerable portion of this work was devoted to the development of Health Indices that are uniquely tailored to THESL's assets and the condition information available.

The report presents the Health Indices derived for the asset classes and provides some comparison of these indices with the previously used age-based method of asset condition assessment. The Health Index method provides THESL with a tool for improved tracking of asset condition, and managing and budgeting for asset replacement.

PROCESS

The following process was followed.

1) Prioritize all asset classes based upon the number and reliability impact the assets represent to THESL.
2) Define the asset information needed to determine and evaluate asset condition against predefined condition indicators, expected results or specifications for all high priority asset classes.
3) Provide documentation and information on industry best practices and understanding of the asset deterioration process and the failure modes and consequences (including any mean time to failure trends); and define the asset condition and asset end-of-life criteria for all high priority asset classes.
4) Review the adequacy of existing asset condition documentation (both condition information and decision criteria) on all high priority asset classes and determine the additional condition information required to adequately assess asset condition.
5) Collect the necessary asset condition information. This information may be obtained from existing databases or through regular testing, surveys or inspections. Define the measurements, and coordinate and schedule the necessary work with THESL staff to collect statistically relevant population samples of asset condition information that will enable a condition assessment of the asset population in question.
6) Create asset condition health indicators for all asset classes from the asset condition information.

7) Analyze the asset condition and performance information to identify population condition, performance trends and high risks and impacts of asset condition on meeting business objectives, including service quality standards.
8) Verify and confirm that the asset condition assessment results reflect actual field condition ("spot audits").

RESULTS

The findings of Kinectrics' review of asset condition at THESL are detailed in the report entitled "Distribution Asset Condition Assessment for Toronto Hydro-Electric System Limited, Report K-012905-RA-002-R00", which is attached to this schedule.

In the majority of cases, the condition of the assets was within the range expected for distribution assets that are well maintained. Subject to the clarifications provided in the report, in general, Kinectrics found that the available records of assets provided by THESL accurately reflected the condition of the equipment in service.

In the case of a few specific assets classes at THESL, there are indications that assets may be deteriorating faster than they are being replaced and these require actions beyond routine maintenance. Indications of this include the increasing failure rates and the poor Health Indices of some classes of asset. For example, direct buried underground cable is a major asset class that suffers from this deterioration.

The prime results of the condition assessment for each asset class, based on existing condition data, are shown in the following Table 1. This is an ultimate best estimate of the condition of each asset class determined using the Health Index method, or the age-based method where sufficient condition data was not yet available at THESL. The percentage of the total population for each asset class in each condition category, "very good", "good", "fair", "poor", and "very poor", is shown in the "Asset Condition"

column. The results show that most assets are in very good or good condition. This indicates in general that the maintenance and capital replacement programs at THESL have been well designed and executed.

The final column on the right hand side indicates the number of assets that are expected to require replacement within the next ten years and the percentage of the total asset class that this represents. It is recommended that the assets in “very poor” condition be planned for replacement in two to three years, and assets in “fair” condition be planned for replacement in four to ten years. It is anticipated that the assets now in “fair” condition will be in “very poor” condition by the end of the ten years.

Table 1: Summary of Asset Condition

Asset Group	Asset Condition					Total Population	EOL within 10 years Units (%)
	Very Good	Good	Fair	Poor	Very Poor		
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1,732	87 (5%)
Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7,490	2,140	1,070	30,709	10,700 (35%)
Submersible Transformers	3,095	3,094	1,470	420	210	8,289	2,100 (25%)
Vault Transformers	7,178	3,900	1,330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4,950	4,950	770	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6,388	3,194	159,700	31,940 (20%)
Overhead Switches - Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches - Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Cable - XLPE in Ducts	N/A	2,497	0%	0%	N/A	2,497	0 km (0%)
Underground Cable - PILC in Ducts	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable - XLPE Direct Buried	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4,985	4,985	71	20	10	10,071	101 (1%)

Note: N/A indicates no data was available

The assets that require the most significant replacement programs in the next 10 years are:

- Direct buried underground cable (61% of the population)
- Automatic transfer switches (63%)
- Station transformers (50%).
- Pole mounted transformers (35%)
- Network transformer/protector units (32%)

Of the list above, the assets with the largest impact on reliability and cost are the direct buried underground cable and the station transformers. A risk assessment was performed in the context of a larger prioritization of all assets. The final method and recommended plan are detailed in the 2007-2016 Electrical Distribution Plan, filed at Exhibit D1, Tab 8, Schedule 10 of this Application.

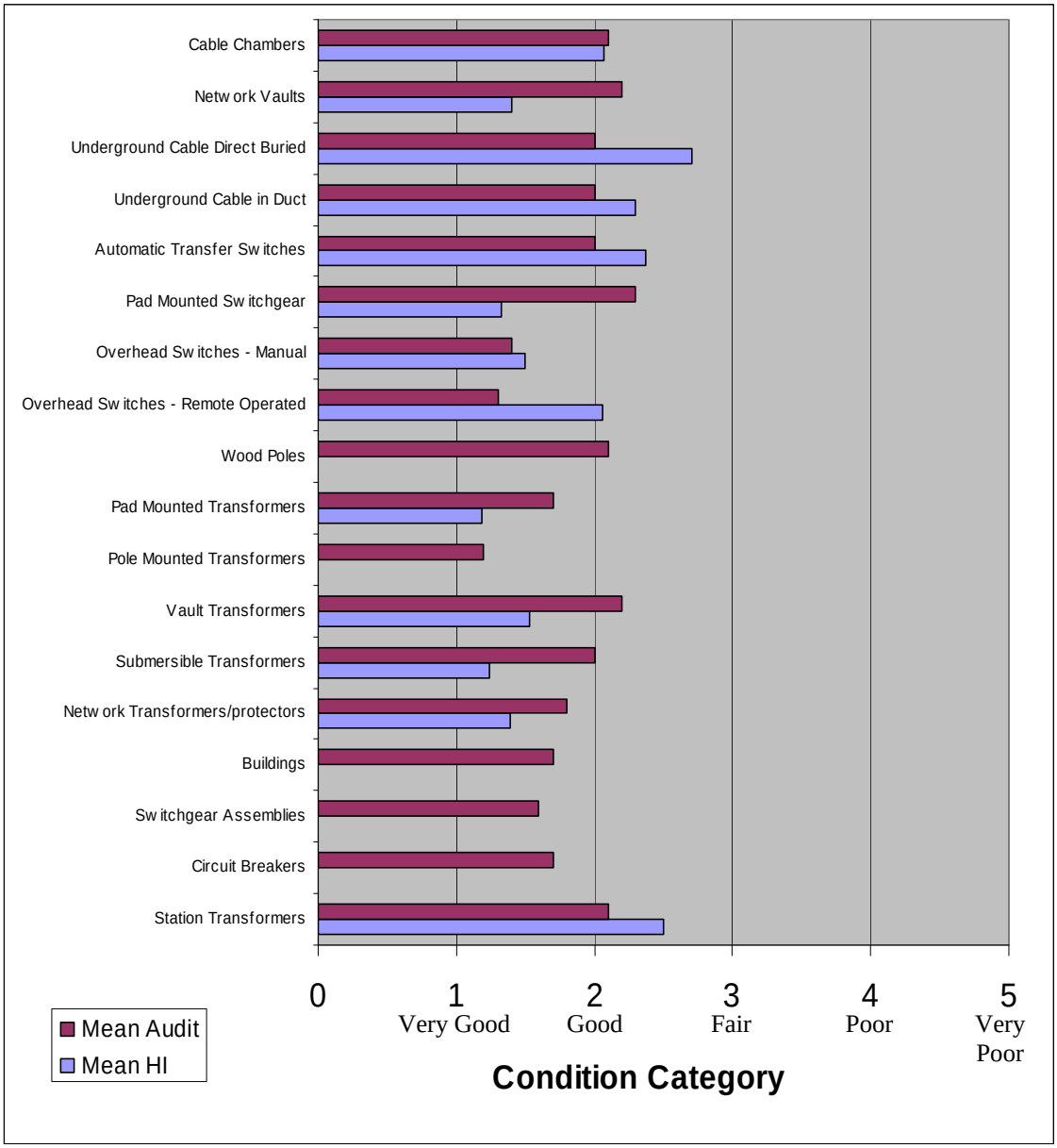
A field audit of asset condition was conducted to confirm the results of the asset condition assessment based on existing information. A comparison of the average condition determined by the audit with the average condition based on existing condition data is shown in the bar chart of Figure ES-1. The field audit verified the Health Index results for most assets. Some differences are expected between the two methods of assessing asset condition due to the different condition criteria used in the two methods. The Health Index method is considered to be more accurate in cases where condition data existed in adequate quantity and quality. All equipment was found to be in “good” condition on average, except for underground cables where the Health Index method indicated only “fair” condition on average.

The asset condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data

can be collected specifically designed to provide a more comprehensive indication of condition. There was enough overlap between the two sets of data (the set for guiding maintenance and the set for calculating Health Indices) that the Health Indices could be calculated for eight classes of equipment, including the most critical – underground cables and station transformers.

There was insufficient available data on which to base a Health Index for wood poles, pole mounted transformers, buildings, switchgear assemblies, and circuit breakers. However, Health Index methods were developed for these assets so that, in the future, when data has been collected to support the Health Index calculation, these assets can be assessed more accurately with the Health Index method.

Figure 1: Comparison of Health Index and Audit Results



DISTRIBUTION ASSET CONDITION ASSESSMENT FOR TORONTO HYDRO ELECTRICAL SYSTEMS LIMITED

Kinectrics Inc. Report No.: K-012905-RA-0002-R00

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

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DISTRIBUTION ASSET CONDITION ASSESSMENT
FOR
TORONTO HYDRO ELECTRICAL SYSTEMS LIMITED

Kinectrics Inc. Report No.: K-012905-RA-0002-R00

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Dated: Friday, February 2, 2007

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Toronto Hydro Electric Systems Limited.

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REVISIONS

Revision Number	Date	Comments	Approved
Draft 0	**June 20, 2006**		
Draft 1	**October 12, 2006**		
Final 0	**January 25, 2007**		

EXECUTIVE SUMMARY

Arising from the 2006 rate application, the Ontario Energy Board requested that THESL submit an Asset Condition Assessment report in support of future rate applications. The Asset Condition Assessment is fundamental in developing maintenance plans and long-term asset replacement and capital investment plans. It is expected that knowledge of the asset condition will assist in defining immediate and then longer term programs and expenditures to ensure that assets are well managed and future rate shocks due to uneven capital replacements can be avoided.

THESL retained the services of Kinectrics Inc., experts on the technical aspects of the distribution utility business and particularly in the subject of condition assessment and Health Indices, to conduct an asset condition assessment and a field audit of asset condition.

This report provides an assessment of THESL's distribution asset condition based on existing available documentation, an audit of the assets, and an estimate of how many assets will require replacement within the next year and the next ten years.

A considerable portion of this work was devoted to the development of Health Indices that are uniquely tailored to THESL's assets and the condition information available. The report presents the Health Indices derived for the asset classes and provides some comparison of these indices with the previously used age-based method of asset condition assessment. The Health Index method provides THESL with a tool for improved tracking of asset condition, and managing and budgeting for asset replacement. The project has provided spreadsheets that implement the Health Index formulation.

The findings of Kinectrics review of asset condition at THESL are detailed in the balance of this report. In the majority of cases, the condition of the assets was within the range expected for distribution assets that are well maintained. Subject to the clarifications provided in this report, in general, Kinectrics found that the available records of assets provided by THESL accurately reflected the condition of the equipment in service.

In the case of a few specific assets classes at THESL, there are indications that assets may be deteriorating faster than they are being replaced and these require actions beyond routine maintenance. Indications of this include the increasing failure rates and the poor Health Indices of some classes of asset. For example, direct buried underground cables are a major component that suffers from this deterioration.

The prime results of the condition assessment for each asset class, based on existing condition data, are shown in the following Table ES-1. This is an ultimate best estimate of the condition of each asset class determined using the Health Index method, or the age-based method where sufficient condition data was not yet available at THESL. The percentage of the total population for each asset class in each condition category, "very good", "good", "fair", "poor", and "very poor", is shown in the "Asset Condition" column. The results show that most assets are in very good or good condition. This indicates in general that the maintenance and capital replacement programs at THESL have been well designed and executed.

The final column on the right hand side indicates the number of assets that are expected to require replacement within the next ten years and the percentage of the total asset class that this represents. It is recommended that the assets in “very poor” condition be planned for replacement in the next year, assets in “poor” condition be planned for years 2 and 3, and assets in “fair” condition be planned for replacement in 4 to 10 years. It is anticipated that the assets now in “fair” condition will be in “very poor” condition by the end of the ten years.

Table ES-1 Summary of Asset Condition

Asset Group	Asset Condition					Total Population	EOL within 10 years
	Very Good	Good	Fair	Poor	Very Poor		Units (%)
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1732	87 (5%)
Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7490	2140	1070	30,709	10,700 (35%)
Submersible Transformers	3095	3094	1470	420	210	8,289	2,100 (25%)
Vault Transformers	7178	3900	1330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4950	4950	770	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6388	3194	159,700	31,940 (20%)
Overhead Switches – Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches – Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Cable – XLPE in Ducts	N/A	2497	0%	0%	N/A	2,497	0 km (0%)
Underground Cable – PILC in Ducts	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable – XLPE Direct Buried	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4985	4985	71	20	10	10,071	101 (1%)

Note: NA indicates no data was available

The assets that require the most significant replacement programs in the next ten years are:

- Direct buried underground cable (61% of the population)
- Automatic transfer switches (63%)
- Station transformers (50%).
- Pole mounted transformers (35%)
- Network transformer/protector units (32%)

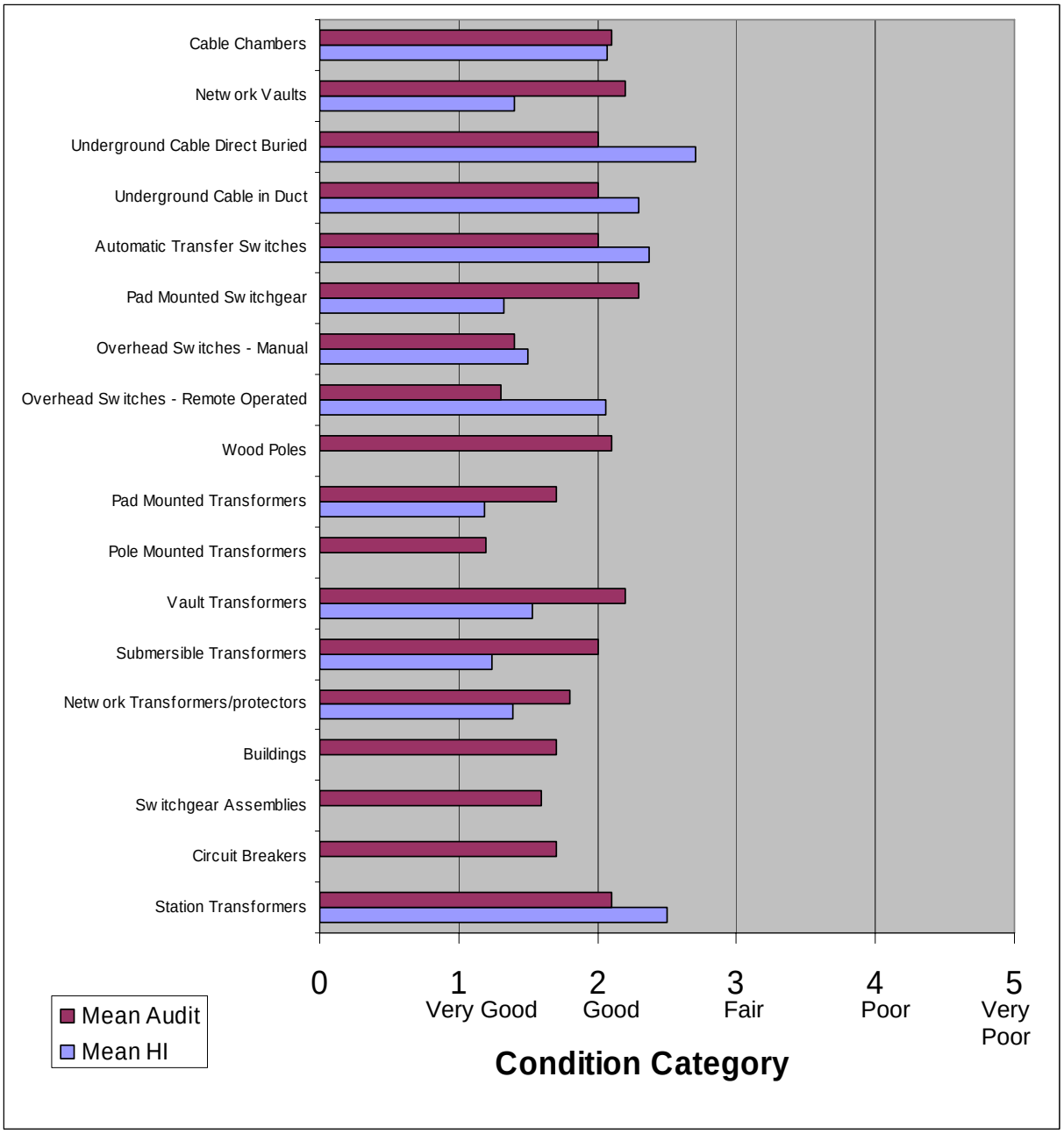
The assets requiring replacement and with the largest impact on reliability and cost are the direct buried underground cable and the station transformers. A formal risk assessment is recommended to prioritize the required asset replacements.

A field audit of asset condition was conducted to confirm the results of the asset condition assessment based on existing information. A comparison of the average condition determined by the audit with the average condition based on existing condition data is shown in the bar chart of Figure ES-1. The field audit verified the Health Index results for most assets. Some differences are expected between the two methods of assessing asset condition due to the different condition criteria used in the two methods. The Health Index method is considered to be more accurate in cases where condition data existed in adequate quantity and quality. All equipment was found to be in “good” condition on average, except for underground cables where the Health Index method indicated only “fair” condition on average.

There was insufficient available data on which to base a Health Index for wood poles, pole mounted transformers, buildings, switchgear assemblies, and circuit breakers. However, Health Index methods were developed for these assets so that, in the future, when data has been collected to support the Health Index calculation, these assets can be assessed more accurately with the Health Index method.

The asset condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data can be collected specifically designed to provide a more comprehensive indication of condition. There was enough overlap between the two sets of data (the set for guiding maintenance and the set for calculating Health Indices) that the Health Indices could be calculated for eight classes of equipment, including the most critical, underground cables and station transformers. It is recommended that the data required for the Health Index method be collected in the future.

Figure ES-1 Comparison of Health Index and Audit Results



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DISTRIBUTION ASSET CONDITION ASSESSMENT FOR TORONTO HYDRO ELECTRIC SYSTEM LIMITED

1 INTRODUCTION

Toronto Hydro-Electric System Limited (THESL) is the regulated electric distribution utility affiliate of Toronto Hydro Corporation. It is the largest municipal electric distribution utility in Canada, delivering electricity to a broadly diversified, residential, commercial and industrial customer base in the City of Toronto. The utility serves more than 676,000 customers. It achieved its present structure in 1998 upon the amalgamation of six municipal utilities.

THESL distributes approximately 18 percent of the electricity consumed in Ontario. In 2005, THESL sold 5,724,299 residential megawatt-hours and 20,647,870 commercial/industrial megawatt-hours. Peak load was 5,005 megawatts in July 2005. Load growth at the utility is estimated at 1% per year. The utility's annual revenue is approximately $2.6 Billion. THESL employs 1,313 people in a variety of trades and professions.

In general, the subject of this report concerns the distribution system assets of THESL and their life-cycle management to end-of-life and replacement. THESL operates $1.585 billion of capital assets comprised primarily of an electricity distribution system located in the City of Toronto. The utility utilizes 35 transmission stations and a single control center. In approximate numbers THESL's major assets include 280 station transformers, 159,000 poles, 10,000 cable chambers, 8,400 km of overhead conductor, 7,500 km of underground cable, 31,000 primary switches, and 58,000 distribution transformers.

THESL maintains and replaces assets in accordance with an asset management model. THESL is organizationally structured with its Asset Manager functionally separated within the company from the service providers. The Asset Manager develops long-term asset management strategies and policies, develops all distribution plant capital investment programs, develops all distribution plant maintenance programs and ensures execution of programs by the internal and external service providers.

THESL distribution plant maintenance uses a Reliability Centered Maintenance methodology. Maintenance programs are derived from Reliability Centered Maintenance (RCM) analyses. This includes preventive, predictive, corrective and emergency maintenance programs. RCM is designed to establish the optimal maintenance required to achieve a desired operational performance.

At this point, investments to rebuild and sustain THESL's existing plant form the largest pool of distribution plant capital investments. Despite performing maintenance according to developed plans, distribution assets will reach a point where no reasonable amount will maintain the reliability or safety of the equipment and it may fail if not replaced.

Age of assets is one indicator that THESL has applied to anticipate the end of life of an asset class. In various recent reports THESL has estimated that 25% to 40% of their power system assets have exceeded age-based end-of-life criteria. THESL is cognizant that age data used was not precise as for some assets the age was based on general assumptions regarding the time of installation of equipment in grid blocks of the system. While age profiling provides some useful guidance, it has been recognized that not all older assets are necessarily in poor condition and not all newer assets are immune from degradation and failure.

Condition monitoring is a method that can be used to achieve more effective management of the end of life of distribution assets. The concept of a Health Index is being adopted in the power distribution industry to provide a qualitative indication of the condition of an asset and asset populations. Condition monitoring is more data intensive than tracking age to determine the timing of replacement for an asset. Different condition criteria are required to assess the various assets on the distribution system. Inspection and testing of assets is one source of condition information. Reliability statistics such as failure frequency can also be used as input to condition assessment. Ultimately the condition of the asset must be combined with the impact or consequence of failure of an asset to develop a replacement program.

In early 2006, THESL appeared before the Ontario Energy Board with a rate application. Arising from the 2006 rate application, the Ontario Energy Board has requested that THESL submit an Asset Condition Assessment report in support of future rate applications. The Asset Condition Assessment forms a significant input into long term capital planning and is fundamental in defending long-term capital investment plans. THESL intends to prepare a 10 Year Capital Investment Plan in part based on the findings of the asset condition assessment results. It is expected that knowledge of the asset condition will assist in defining immediate and then longer term programs and expenditures to ensure that assets are at a sustainable level and future rate shocks due to peaking replacements can be avoided. Questions exist as to whether existing reactive maintenance and replacement programs must be accelerated to keep up with the impending end of life of assets. The reliability impact and risk of losing major assets is also a prime concern at THESL.

THESL retained the services of Kinectrics Inc., who are experts on the technical aspects of the distribution utility business, and particularly in the subject of condition assessment and Health Indices, to conduct an asset condition assessment audit.

This report presents the findings of the review of THESL's assets. The report provides an assessment of the asset condition based on existing available documentation, an audit of the assets themselves, and review of historic maintenance and capital programs and budgets. A considerable portion of this work was devoted to the development of Health Indices uniquely tailored to THESL's assets and the condition information available. The report presents the Health Indices derived for the asset classes and provides some comparison of these indices with the aged based approach of asset assessment.

1.1 Objective

The objective of the work discussed in this report was to conduct an asset condition assessment (ACA) for THESL for key distribution plant assets within the limitations of schedule defined by THESL. The asset condition assessment was designed to quantify the extent of degradation and provide a recommendation as to the number of assets that would likely require replacement within future time horizons.

1.2 Scope of Work

The scope of the work in this asset condition assessment included:

- prioritization of an identified set of asset classes based upon the number and reliability impact they represent to THESL.
- definition of the information needed to determine and evaluate asset condition against condition indicators for the high priority asset classes.
- providing information on industry best practices and understanding of the asset deterioration process and the failure modes and consequences and defining the asset end-of-life criteria for high priority asset classes
- reviewing the adequacy of existing asset condition information and decision criteria for high priority asset classes and determining additional condition information required
- collecting available asset condition information from existing databases including information from regular testing, surveys and inspections.
- defining condition criteria and coordinating with THESL staff to collect statistically relevant population samples of asset condition information
- creating asset condition Health Indices for asset classes
- analyzing the asset condition and performance information to identify population condition, and risks and impacts of asset condition
- conducting spot audits to verify that the asset condition assessment results reflect actual field conditions

The scope of this study was confined to a predefined set of THESL's major assets. This study did not have the mandate to review the cost consequences and impacts associated with the loss of assets. The work was also not intended to produce a Capital Investment Plan.

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2 METHODOLOGY

2.1 Asset Classes Assessed

THESL operates $1.585 billion of capital assets comprised primarily of an electricity distribution system located in the City of Toronto. The utility utilizes 35 transmission stations and a single control center. Of the 35 transformer stations; 19 are owned by Hydro One, 15 are jointly owned by Hydro One and THESL, and one is owned solely by THESL. Seventeen of the stations are supplied at 115 kV and the other 18 are supplied at 230 kV. At 20 of the transformer stations voltage is stepped down to 27.6 kV, and at the other 15 it is stepped down to 13.8 kV.

In addition to the terminal stations at 27.6 kV and 13.8 kV, THESL has a substantial 4.16 kV system involving 188 stations that are located in various parts of the City of Toronto. In total, power is distributed at 27.6 kV, 13.8 kV and 4.16 kV through approximately 268, 642, and 631 feeders respectively. THESL distributes electricity through a network of over 9,100 kilometers of overhead wires supported by over 159,000 poles as well as over 7,600 kilometers of underground wires installed in cable chambers and duct systems. Voltage is further stepped down to intermediate levels for the use of customers in the City of Toronto via 59,000 distribution transformers. These transformers are located in buildings, below grade vaults, surface mounted pads or mounted on the poles. Power is distributed throughout the city via radial, loop, and network systems both in underground and overhead plant configurations.

A particular sub-set of THESL's assets were selected for the purpose of this asset condition assessment. The asset categories and classes that are addressed in this assessment are listed in Table 2-1 along with the population in each class. The following provides a brief description of the particular assets in the class with some of their significant characteristics.

It is important to note that the asset classes are large enough that they do not always represent a homogenous set of equipment. Beside the variance in age there are variations in model, types, ratings, installations, environments, etc. All of these factors can potentially have impact on the condition of the individual assets, the ultimate Health Indices and the estimated replacement timing.

Table 2-1 Assets Included in the Condition Assessment

Asset Group	Asset Class	Population
Transformer Stations	230-27.6 kV power transformers	2
	27.6 kV circuit breakers	120
	13.8 kV circuit breakers	743
	27.6 kV switchgear assemblies	2
	13.8 kV switchgear assemblies	50
	Buildings	16
Distribution Stations	27.6 kV-13.8 kV power transformers	34
	27.6 kV-4.16 kV power transformers	166
	13.8 kV-4.16kV power transformers	85
	13.8kV switchgear assemblies	37
	4.16 kV switchgear assemblies	183
Overhead Distribution	Poles, wood and concrete	159,700
Network Distribution	Transformer/protector units	2,055
Radial Distribution	27.6 kV, 13.8 kV pole mounted remotely operable load interrupter switches	505
	27.6 kV, 13.8 kV pole mounted manually operable load interrupter switches	946
	27.6 kV, 13.8 kV, 4.16 kV pad mounted switchgear	742
	13.8 kV auto transfer switches	113
	Underground primary cable (in duct)	3,770 km
	Underground primary cable (direct buried)	1,481 km
	27.6 kV, 13.8 kV, 4.16 kV polemounted transformers	30,709
	27.6 kV, 13.8 kV, 4.16 kV padmounted transformers	5,609
	27.6 kV, 13.8 kV, 4.16 kV submersible transformers	8,289
	27.6 kV, 13.8 kV, 4.16 kV vault transformers	12,409
Civil	Cable chambers	10,071
	13.8 kV network transformer vaults	1,084

2.2 Asset Replacement Costs

As an indicator only of the overall significance of each asset class to THESL, an estimate of the total replacement cost of the major assets has been made based on the data provided. The following Table 2-2 summarizes the input data.

Table 2-2 Total Replacement Value of Asset Classes[1]

Asset Class	Cost/Unit to Replace	Units	Population	Replacement Cost (million $)
U/G Feeder Cable - Direct Buried	$ 500[2]	m	300000	150.00
U/G Dist Cable - Direct Buried	$ 280[2]	m	1188000	332.64
U/G Feeder Cable - in Duct	$ 150[3]	m	754000	113.00
U/G Dist Cable - in Duct	$ 150[3]	m	3016000	452.00
Poles	$ 5,780[4]	each	159000	919.02
O/H Transformers	$ 4,266	each	30709	131.00
U/G Transformers	$ 12,000	each	8289	99.47
Padmount Transformers	$ 25,000	each	5609	140.23
Building Vault Transformers	$ 12,000	each	12409	148.91
Network Transformers/protectors	$ 85,000	each	2055	174.7
O/H Switches - Manual	$ 8,000	each	946	7.57
O/H Switches - Remote	$ 25,000	each	505	12.63
UG ATS Switches	$ 19,428	each	113	2.20
Padmount Switches	$ 26,035	each	742	19.32
Cable Chamber Roof Replacement	$ 12,000	each	10071	120.85
Vault Roof Replacement	$ 22,566	each	1084	24.46
Stations Transformers	$ 180,000	each	287	51.66
Stations Circuit Breakers	$ 30,000	each	1732	52.00
Stations Switchgear	$ 1,750,000	each	272	476.00
Stations Buildings	$ 5,000,000	each	16	80.00

NOTES

1 The replacement cost per unit data was obtained from THESL's "Electric System Distribution Asset Strategy 2006" Table A1-1
2 Direct buried cable is replaced with cable in concrete encased duct
3 Does not include replacing the duct structure
4 The figure for poles includes insulators, hardware and conductors.
5 It was assumed that 20% of the cable was feeder cable and 80% distribution cable
6 Replacement costs provided may be maximum values rather than average values

The asset classes listed in Table 2-2 are not intended to be an exhaustive list of the asset classes of THESL but a list of the most important for determining priorities. Total replacement costs calculated for the assets of Table 2-2 therefore does not represent the total replacement value of the assets of THESL.

2.3 Asset Prioritization Considering Reliability Impact

As a further indicator of the relative importance of the asset classes to THESL, consideration was given to the reliability impact that each asset class could have on the THESL system.

The priority of the assets included the asset condition assessment was investigated based on their expected contribution to the system reliability. In the analysis, reliability was considered on a per customer basis. This means that the reliability impact of the failure of an asset depends critically on how many customers the asset serves as well as on how often it fails. Reliability also depends on how long the customers are without power. This is not necessarily the repair time for the asset that failed, since power can often be restored by using alternate equipment. In this case it is the fault location and switching time that determines the duration of the customer outage. Some equipment, usually close to the customer, may not have an alternate and the repair time will then be the outage duration.

When industry average failure rates are used, the highest priority asset classes are:

- station transformers
- switchgear
- breakers
- primary feeder cables.

Single phase distribution cables are often direct buried and have higher failure rates than feeder cable which is more often in duct, but each failure affects few customers and the duration is short because of the open loop design of the system. Overhead switches rarely cause an outage directly but instead they fail when they are called upon to operate to isolate a separate failure and restore power. This extends the duration of the separate outage and affects reliability in that way. The failure of Individual distribution transformers affects too few customers for this to be a large contributor to reliability problems at the usual rates of transformer failure. Vaults and cable chambers fail at a low enough rate that they do not cause significant reliability problems.

On the basis of reliability impact the following asset classes top the list of asset classes that should be of prime concern to THESL:

- station transformers,
- station switchgear
- feeder cable

However the actual contributions of equipment to the SAIFI, SAIDI and CAIDI indices at THESL indicate that cables are actually the largest contributor. This is may be because the station equipment condition is carefully monitored and THESL failure rates for station equipment may be below the industry averages. The reliability considerations based on industry average failure rates indicate that THESL should continue to monitor station equipment carefully, even though it is not a major contributor to customer outages at the present time.

2.4 Asset Degradation and End-Of-Life Criteria

Assessing asset condition requires an understanding of the degradation or deterioration process of the equipment in the asset classes. The failure modes of the equipment in the selected asset

classes and the consequence of failures is discussed in the following sections. This information was used in the development of the condition criteria for THESL's assets and hence in the development of the Health Indices for the equipment. Information is provided on the end-of-life for equipment in the following asset classes:

- Power Transformers
- Circuit Breakers
- Switchgear
- Buildings
- Poles – Wood, Concrete
- Network Transformers
- Network Protectors
- Switches – Remote and Manually Operated
- Padmounted Switchgear
- Auto Transfer Switches
- Primary Cable – PILC, XLPE, In-Duct, Direct Buried
- Distribution Transformers – Polemounted, Padmounted, Submersible, Vault
- Cable Chambers and Vaults

2.4.1 Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For Distribution stations, power transformer ratings typically range from 5 MVA to 30 MVA. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, their ratings may typically range from 30MVA to 125 MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary and secondary windings
- Laminated iron core,
- Internal insulating mediums,
- Main tank,
- Bushings,
- Cooling system, including radiators, fans and pumps (Optional),
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

The primary and secondary windings are installed on a laminated iron core and serve as the coils in which electromotive force is produced when alternating magnetic flux passing through the core links with the windings. The internal insulating mediums provide insulation for energized coils. Insulating oil serves as the insulating medium as well as serves as the coolant.

Due to its low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress mineral oil is most widely used transformer insulating material. The transformer coil insulation is reinforced with different forms of solid insulation that include wood-based paperboard (pressboard), wrapped paper and insulating tapes. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil ends up being higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped paper which is either wood or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads coming from the windings.

The main tank holds the active components of the transformer in an oil volume and maintains a sealed environment through the normal variations of temperature and pressure. Typically the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformers. Main tank designs can be classified into 2 types those being conservator type and sealed type. Conservator types have an externally mounted tank that usually holds 10% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. The liquid seal also provides some protection against moisture ingress into the insulation systems. A sealed tank design incorporates a gas header on top of the oil volume using nitrogen or dry air. This gas header can be either in a positive pressure or vacuum mode depending on the system loading or ambient changes. The pressure and vacuum conditions of a sealed tank design are controlled by the use of a regulator that ensures the tank is within its design limits.

Bushings are used to facilitate the egress of conductors to connect ends of he coils to power supply system in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on metallic flange. The phase leads are either independent paper insulated, or are an integral part of the bushing. At the higher voltage levels, additional insulation is incorporated in the form of mineral oil and/or wound paper leads installed within the porcelain column.

The purpose of cooling system in a power transformer is to efficiently dissipate heat generated due to copper and iron losses and help maintain the windings and insulation temperature within acceptable range. The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural).
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced).
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced).

Off load tap changer allows the transformer turns ratio to be altered over a small range to effect changes in output voltage as required. An off load tap changer typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2 ½ % steps. An off load tap changer must only be operated with the transformer off potential. Under load tap-changers (ULTCs) allow for automatic voltage regulation in response to varying load conditions on line. ULTCs

consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. Instrument transformers include CT's and PTs for metering or control purposes. Power transformers are equipped with externally mounted control cabinets for voltage and current control relay, secondary control circuits, and in some cases the tap changer motor and position indicators.

Both from the view of financial and operational risk, power transformers are the most important asset employed on the distribution and transmission systems. A significant proportion of power transformers employed by North American utilities were installed in the 1950s, 1960s or early 1970s. So despite the fact that the number of transformer failures arising due to End of Life (EOL) has to date been relatively small there is awareness that a majority of the transformer population will soon be reaching the end of life and it may significantly impact transformer failure rates.

For a majority of transformers, EOL is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

Transformer oil is made up of complex hydrocarbon compounds, containing anti-oxidation compounds. Despite the presence of oxidation inhibitors oxidation occurs slowly under normal operating conditions. The rate of oxidation is a function of internal operating temperature and age. The oxidation rate increases as the oil ages, reflecting both the depletion of the oxidation inhibitors and the catalytic effect of the oxidation products on the oxidation reactions. The products of oxidation of hydrocarbons are moisture, which causes further deterioration of insulation system and organic acids, which result in formation of solids in the form of sludge. Increasing acidity and water levels result in the oil being more aggressive with regard to the paper and hence accelerate the ageing of the paper insulation. Formation of sludge adversely impacts the cooling capability of the transformer and adversely impacts its dielectric strength. An indication of the condition of insulating oil can be obtained through measurements of its acidity, moisture content and breakdown strength.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains; therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). But this test can be performed only after de-tanking or the core and coil and therefore, is not a practical test. For a new transformer the DP value of the paper is normally greater than 1,000. As the paper ages this figure gradually decreases. When the DP value approaches below 250 the paper is in a very brittle and fragile condition. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharge which can be initiated if the level of moisture is allowed to develop in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of Furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for power transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

Under load tap changers are prone to failure resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning and replacement of contacts and any defective components in the mechanism, and changing or reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis from tap changers is considered less useful than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal ULTC operation.

The health indicator parameters for power transformers include:

- Condition of the bushings,
- Condition of transformer tank,
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results and
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 40 to 50 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, EOL. There are a number of contributory factors to the long life of

transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Consequences of power transformer failure include customer interruptions over significantly long durations. Catastrophic failure of transformers may also result in injury or death, fire and damage to property. There are also environmental risks due to oil spills during tank failures. These risks are more pronounced where transformers are located near water bodies or contain PCBs.

2.4.2 Circuit Breakers

The oil circuit breakers (OCB) represent the oldest type of breaker design, that have been in use for over 70 years. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium) and minimum oil breakers (in which oil provides the arc quenching function only). Generally, 4 to 8 fully rated interruptions represent an OCB's useful service time between major maintenance. This duty cycle can result in excessive contact erosion, carbonisation of oil, and the need for maintenance.

Vacuum breakers consist of fixed and moving butt type contacts in small evacuated chambers (i.e., bottles). A bellows attached to the moving contact permits the required short stroke to occur with no vacuum losses. Arc interruption occurs at current zero after withdrawal of the moving contact. Utilities typically install vacuum breakers indoors in metalclad switchgear. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

Air magnetic breakers use the magnetic effect of the current undergoing interruption to draw an arc into an arc chute for cooling, splitting and extinction. Sometimes, an auxiliary puffer or air blast piston may help interrupt low-level currents. These designs are commonly used in metalclad switchgear applications. The air magnetic breakers have short duty cycles, require frequent maintenance and approach their end-of-life at much faster rates than either SF6 or vacuum breakers. They also have limited transient recovery voltage capabilities and can experience restrike when switching capacitive currents.

SF6 Circuit breakers were first developed in the late 1960s and based on air blast technology. SF6 breakers interrupt currents by opening a blast valve and allowing high pressure SF6 to flow through a nozzle along the arc drawn between fixed and moving contacts. This process rapidly deionizes, cools and interrupts the arc. After interruption, low-pressure gas is compressed for re-use in the next operation.

The circuit breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. The International Council on Large Electric Systems' (CIGRE) have identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete;
- Maintenance overhaul requirements; and
- Circuit breaker age.

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

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

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problem in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections;
- Oil contamination and/or leakage; and
- Deterioration of concrete foundation affecting stability of breakers.

For OCBs, the interruption of load and fault currents involves the reaction of high pressure with large volumes of hydrogen gas and other arc decomposition products. Thus, both contacts and oil degrade more rapidly in OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions with contact erosion and oil carbonization will lead to the need maintenance, including oil filtration. Oil breakers can also experience restrike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures.

SF6 circuit breakers rarely fail from internal degradation or insulation breakdowns. When such failures do occur, they typically result from design or manufacture deficiencies, and they happen early in the breaker's life. There is insufficient experience with failures from long-term SF6 chamber degradation. SF6 insulation systems are sensitive to enhanced stress caused by metal particles or other protrusions on live parts. Metallic particles generated by moving metal parts in the tank can accumulate and cause internal flashovers. Particle initiated failures do not appear age-related, since the problem has occurred on relatively new breakers. Low temperatures have caused operational problems and failures of SF6 breakers. Most international testing standards for these breakers specify minimum temperatures of -30° C, but many Canadian users require operation at -40° C or below. At low temperatures, early double pressure designs experience gas leaks as well as mechanism and ancillary system problems, including failures. Single pressure designs also may have gas leaks, with gas seals and valves presenting weak points. SF6 loss and the ingress of moisture and air compromise breaker performance. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

SF6 is extremely stable. Even at high arcing temperatures limited SF6 breakdown occurs. Also, with use of a suitable desiccant most breakdown products recombine to form SF6. Consequently, SF6 breakers can operate under fault conditions much longer than OCBs or ABCBs before needing maintenance. Manufacturers generally state that these breakers can perform 20 to 50 operations at full rated fault levels before requiring maintenance.

Recently, concerns have arisen about the greenhouse properties of SF6. It is one of the gases specifically mentioned in the Kyoto Agreement. Canada has not issued regulations for SF6, but has made a commitment to reduce the country's overall greenhouse gas emissions.

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 25 to 50 years.

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

2.4.3 Switchgear

The metalclad switchgear is typically compartmentalized, with separate cells for the following functions:

- Bus-bar Compartment
- Switching Compartment

- Cable Compartment
- Control Compartment

The bus-bar compartment may be open across the entire length of gear, or it may be segmented into sections, as many as one per feeder. The bus-bars connect adjacent cells. Depending on the voltage and current level, the bus-bars can be bare or insulated and made of copper or aluminum. The switching compartments house the switching devices, i.e. breakers, disconnect switches etc. Design of breakers allows them to be fully engaged (connected); withdrawn to a test position, but still contained in the closed cell; or fully withdrawn from the compartment, usually for the purposes of inspection and maintenance. When in the engaged position, the breaker connects to the sub-bus, and the outgoing/incoming feeders, through tulip type contacts while the breaker controls connect through a separate contact block. Entry and exit for exterior power connections is usually by means of cables, but occasionally this may be carried using bus duct through the cable compartment. Current transformers, as well as the cable terminations are installed in the cable compartment. Normally, the required local control, protective relaying and metering devices are all placed within the compartment or on the doors of the compartment.

All compartments are isolated from each other by metal partitions to prevent inadvertent contact with live parts, particularly during maintenance. In the breaker compartment, a moveable shutter shields the main contacts when the breaker is withdrawn, and is retracted when the breaker is being racked in to allow breaker connection to the main contacts. Final racking in of the breaker can only be done from outside the switchgear to ensure personnel safety. Also for safety reasons, the breaker door can only be opened after the breaker is tripped.

A majority of the utilities are specifying metalclad switchgear to conform to arc-proof design standards - EEMAC Standard G14.1. Several classes of arc proof gear exist under this Standard. Under Type A arc-proofing, personnel are safe only in front of the gear. Under the Type B designation, personnel are safe all around the gear, front, back and sides. These arc-proof definitions conform in broad generality to the comparable IEC Publication 298. However, the EEMAC Standard goes further in defining a Type C gear, in which the arc resistance extends all around the gear and limits the extent of the arc allowed under fault conditions to prevent penetration of the arc between compartments within a cell, or between cells. The only exception is that an arc within a bus compartment may be allowed to break into its associated cell. Some standards go further, and define a C+ rating which prevents this exception and specifies that the arc must remain in the cell portion of the bus in which it started.

Any switchgear arc will cause an explosive rise in pressure, and initiate the release of gases and metallic particles. Arc-proof gear requires the provision of pressure relief vents to ensure release of such gases. Explosion products must be conducted upwards, away from the gear, and more importantly, away from any personnel that may be in the area. The minimum number of such vents must be at least one per separate internal compartment.

While the switchgear degradation is a function of a number of different factors, such as condition of mechanical mechanisms and interlocks, degradation of solid insulation and General degradation/corrosion, in most cases end-of-life is related to non-conditional issues. The important issues tend to be capability, obsolescence or specific/generic defects.

If the fault level on the system increases to exceed the rated interrupting value of the switchgear, the switchgear must be upgraded to meet the new requirements or the system reconfigured to reduce the fault levels. For much of the old vintage switchgear currently in use

the original manufacturers no longer exist. It is therefore becoming increasingly difficult to obtain spare or replacement parts. In some cases alternative sources of replacement parts can be located, however, difficulties and failures have occurred where these have not met the original manufacturer's specifications.

As mentioned in earlier sections, some specific problems have given rise to decisions to replace particular types of equipment. In some cases these relate to condition of internal insulation or even susceptibility to general deterioration or corrosion. Discharge related problems with polymeric insulation have in few cases lead to decisions to phase out relatively new vacuum or SF6 equipment.
Failure of cable terminations is a significant contributor towards the overall switchgear failures. Discharge testing using non-intrusive, electro-magnetic and/or ultrasonic detectors provides a convenient way of detecting potential failures. However, periodic measurements of intermittent source of discharge activity are not always able to provide a complete guarantee against future problems.

The switchgear health and condition is indicated by the following parameters:

- Equipment age
- Presence of hotspots (indicated by thermal scan)
- Condition mechanical interlocks
- Condition of controls and relays
- Condition of bus insulation (indicated by megger tests)

The life expectancy for medium voltage distribution switchgear is 35 to 50 years. Failure consequences are serious and include customer interruptions over extended length of time, loss of revenue and employee safety.

2.4.4 Buildings

The asset grouped under buildings at distribution utilities includes housing facilities for substations, warehouses, service centres, offices and other general purpose buildings. While these structures must conform to utility's functional needs they also must conform to local building codes and relevant workplace health and safety regulations.

While many of the comments below apply to all buildings, the write up focuses on buildings housing the electrical substations, since they must meet the most stringent needs. The substation buildings, in addition to the buildings also contain the following subsystems:

Footings and Foundations, providing supporting base for substation equipment. Foundation materials usually consist of reinforced concrete. Since they have load (e.g., static, dynamic and possibly seismic) requirements based on the equipment supported, footings and foundations require proper engineering. In addition, they must conform to elevation and height constraints of particular stations. To ensure stability over time, designs for footings and foundations also must consider environmental issues such as local climate and soil conditions.

Grounds and Landscaping, to provide a pleasant environment for workers and the substation's neighbours. Landscaping also aids in controlling soil erosion, maintaining overall site cleanliness, and facilitating a safe and efficient workplace.

Surface Stone, required in outdoor substation yards to provide safety coordination for step and touch potentials during ground faults

Spill Response and Containment, required to contain spilled materials during equipment failures and minimize environmental harm

Sumps and Sump Pumps, employed wherever the potential exists for water build-up. For example, sump pumps can help keep basement facilities dry or clear water build-up in spill containment systems. Sump pumps are particularly critical in low water table areas.
Lifting Equipment, installed in buildings to facilitate maintenance activities. Lifting equipment ranges from small hoists that assist in managing spare parts' inventories to overhead cranes. In some cases, lifting equipment in substations plays an important role in fast restoration of power following equipment failures.

Buildings at substations house electrical equipment and serve as a base for administrative and service work. The health and condition of buildings is significantly impacted by environmental conditions, particularly rain, wind and snow storms. Because of the presence of electrical equipment, the potential for water ingress presents particular concerns for these assets. Thus, buildings must be weatherproof. Regular preventative maintenance, with occasional major refurbishment of roofs, windows and doors, helps ensure the long-term viability and integrity of buildings. Generally, for well-maintained buildings, operational issues dictate the asset's longevity.

Roof maintenance is the biggest maintenance activity associated with substation buildings. Generally, roof water proofing systems have a shorter life than buildings. Utilities typically replace roofs on a 15 – 20-year cycle. In most substations, feeder cables exist the substation through the basement. These, if not properly sealed can become a source of flooding.

Building inspections usually occur as part of routine visual inspections at 1 – 3 month intervals. Most utilities have inspection checklists to help identify defects and provide overall condition evaluations. Inspection reports also help set priorities for repair programs. Inspections, therefore, help ensure that minor problems receive prompt and effective correction to keep buildings fit for their stated purpose. Spill containment and other civil works also represent important station subsystems. Made primarily from concrete, these facilities may crack, corrode, and shift.

The following factors are commonly considered in establishing the health of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements – condition of roof and windows
- Environmental concerns, e.g. presence of asbestos, mold etc.
- Functional requirements

The life expectancy of buildings is largely dependent on frequency and content of preventative maintenance and may vary from 40 years to 100 years. End of life is reached when the existing buildings are no longer fit for functional requirements or when maintenance and repair costs exceed the annualized cost of a new building. Since in a majority of cases, building failure does not mean structural collapse but means failure of the existing building to provide required

functions economically, consequence of asset failure is financial loss. A major leak or flooding may also result in damage to other assets in the building and may impact power supply reliability.

2.4.5 Poles (Wood and Concrete)

Wood species commonly used on distribution systems are predominately Red Pine, Jack Pine and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

Distribution line design dictates usage of the poles varying in height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into classes (1 to 7), which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable or other telecommunications facilities.

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, of foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulation and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductor from ground potential. These wood pole system components are described below.

The condition of the concrete poles is assessed by taking into consideration reduction in strength due to spalling or mechanical damage caused by vehicular collisions.

The guys, anchors and span-guy poles maintain the mechanical integrity of the pole, when the pole is required to withstand additional stress due to unbalanced line tension. Various guying components include guy hook for direct pole attachment, epoxy rod or porcelain “johnny ball” insulator, 7 strand 5/16” or 3/8” diameter, zinc coated, steel guy wire, and any variety of anchors, depending upon soil conditions. While the Power Installed Screw Anchor (PISA) is predominant, screw anchor, expansion anchor, log (slug) anchor, steel plate anchor, rock (solid hard) anchor and the shale/limestone anchor are also used.

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

To prevent attack and decay of wood poles they are treated with preservatives prior to being installed. The preservatives have two functions, firstly to keep out moisture that is necessary to support the attacking fungus and secondly as a biocide to kill off the fungus spores. Over the period of wood pole use in the electricity industry, the nature of the preservatives used has changed, as the chemicals previously used have become unacceptable from an environmental viewpoint. Nevertheless, effective and acceptable preservatives are available and poles well treated prior to installation have a long life (typically in excess of 50 years) prior to decay resulting in significant damage.

The processes of decay require the presence of the fungus spores plus water and oxygen in order to develop. For this reason the area of the pole most susceptible to degradation is at and around the ground line or at the top of pole. Although it is possible in some circumstances for decay to occur in other locations it is normal to concentrate inspection and assessment of poles in these areas. In addition to the natural degradation processes, external damage to the pole by wildlife can also be a significant problem. This can vary from attack by termites, small mammals or woodpeckers.

Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in); however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice resulting in cracking and separation of the concrete. The spun concrete process used in manufacture of poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers which record and analyze the vibration caused by a hammer blow and identify patterns which indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonics, X-rays, electrical resistance measurement have also been widely used.

Condition assessment of concrete poles can, similarly, be carried out through visual inspections and taking into account the extent of surface deterioration of the pole. There are many factors

considered by utilities when establishing condition of poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The following criteria are used in establishing health and condition of this asset:

- Pole strength (through lab testing on selected samples)
- Existence of cracks for both wood and concrete poles
- Wood pecker or insect caused damage for wood poles
- Wood rot or concrete spalling
- Damage due to fire or mechanical damage
- Condition of guy wires
- Pole plumb ness

The life expectancy of wood poles or concrete poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for significant number of customers.

2.4.6 Network Transformers

Since the individual transformers have no overload protection and are required to stay in service during secondary short circuits, the transformers are designed to withstand heavy short circuit current. Since in a majority of the applications transformers are installed in below grade vaults, the transformer is designed for partially submersible operation with additional protection against corrosion. While network transformers are available in dry-type (cast coil and epoxy impregnation) designs, a vast majority of the network transformers employ mineral oil for insulation and cooling. Therefore, condition assessment criteria and end of life criteria for network transformers is similar to distribution pad-mounted transformers.

For a majority of transformers, EOL is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation, which is described in detail in Section 4.1. However, when employed in location with frequent flooding, transformer tank corrosion also leads to end of life for a significant number of network transformers.

For condition assessment while the frequency and extent of testing is not as rigorous as for power transformers, it is certainly more rigorous than pad mounted or pole mounted distribution transformers. Transformer oil is tested routinely for dielectric strength and moisture content but very rarely it is necessary to carry out gas in oil analysis or Furan measurement.

Network transformer condition is ranked by weighing in the following factors:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of transformer disconnect
- Transfer operating age and winding temperature profile

Network transformers often operate significantly below their nameplate rating and therefore, the anticipated life of transformers is often as high as 40 to 60 years. In-service age and loading levels are good indicators of transformer expired life. Presence of oil leaks, tank corrosion, condition of cable potheads and primary disconnects also included while assessing overall transformer condition.

Single element failures in the network system do not lead to any customer interruptions. Transformer failures that are not properly isolated by protective devices could lead to an eventful failure and collateral damage/failure. Once more than one element is taken out of service, customer interruptions will likely occur. Depending upon the extent of the collateral damage, the damaged equipment may be irreparable leading to long restoration times. Eventful failure may also result in public or staff injury, fire and damage to property. There are also environmental risks due to oil spill as a result of tank failures.

2.4.7 Network Protectors

The relays are, thus, a critical component of the protector and an improper operation of the relays can lead to breaker failure. Traditional relays used to be of electromechanical design type and employed induction discs. They used to be somewhat cumbersome and delicate, requiring frequent maintenance schedules for overhaul and recalibration. Solid-state network protector relays were developed in the early 1990's and they are reported to have increased reliability due to the use of accurate, high reliability, military-grade components, and an increased life expectancy. Solid-state relays meet specifications with respect to vibration, salt spray, fungus and shock. Solid-state relays should require no recalibration.

The breaker design in network protectors employs mechanical linkages, rollers, springs and cams for operation which require periodic maintenance. All network protectors are equipped with special load-side fuses, mounted either internally or external to the network protector housing. The fuses are intended to allow normal load current and overloads while providing backup protection in the event that the protector fails to open on reverse fault current (due to faults internal to the protector or near transformer LV terminals). Every time arcing occurs in open air within the network protector housing, whether due to operation of the air breaker or because of fuse blowing (except silver sand), a certain amount of metal vapour is liberated and dispersed over insulating parts. Fuses evidently liberate more vapour than breaker operation. Over time, this buildup reduces the dielectric strength of insulating barriers. Eventually this may result in a breakdown, unless care is taken to clean the network protector internally, particularly after fuse operations. THESL typically replaces protectors with new or refurbished protectors if the backup fuses have been found to have operated.

Various parameters that impact the health and condition and eventually lead to end of life of a network include condition of mechanical moving parts, condition of inter phase barriers, number of protector operations (counter reading), accumulation of dirt or debris in protector housing, corrosion of protector housing, condition of fuses, condition of arc chutes and time period elapsed since last major overhaul of the protector.

The health of network protector is established by taking into account the following factors:

- Number of operations since last overhaul
- Operating age of protector
- Condition of operating mechanism
- Condition of fuses
- Condition of arc chutes
- Condition of protector relays
- Condition of gaskets and seals for submersible units

The life expectancy of network protectors can vary significantly as a function of the preventative maintenance and number of short circuit interruptions and can vary from 30 years to 50 years. Generally speaking, each trip and close of the primary feeder breaker results in a corresponding trip and close of the protector. However, during these operations, the protector is called upon to interrupt only the transformer magnetizing current. Only during a fault on the medium voltage feeder, the protector is required to interrupt short circuit current and such interruptions on underground fed feeders are rare.

A network protector failure may lead to catastrophic transformer failure or a vault fire and may result in wide spread outages to commercial customers.

2.4.8 Overhead Line Switches

Most distribution line switches are rated 600 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with switch handle locked in open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Generally, THESL uses air break switches in its system. Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod,
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation,
- Loose connections

- Non functioning padlocks,
- Insulators damage,
- Missing ground connections,
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involve visual inspections which would reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective test to locate hot spots.

The following parameters are considered in establishing the asset health:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Operating age of disconnect switch

The average life expectancy of overhead switches is approximately 40 years. Consequences of overhead line switch failure may include customer interruption and health and safety consequences for operators.

2.4.9 Padmounted Switchgear

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site. On an average, the pad mounted switchgear, when maintained regularly can be expected to provide a service life of 30 to 35 years.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, padmounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

There are other defects that are important and require intervention, but do not result into a failure and can be rectified by field action. For example, graffiti on padmounted switchgear is often considered an eyesore and may even conceal important safety and operating signage. Re-painting the outside of the case and replacing the signage can usually be done with no disruption of power. In areas with repeating problems, anti-graffiti paint may be an effective solution.
Rusting of a padmounted switchgear enclosure can lead to perforation and a public safety hazard. Touch-up and re-painting may delay the rusting process, but eventually a planned replacement of the equipment will be required.
Accumulation of dirt and pollution can often be removed by cleaning, and on-line cleaning using dry ice is one of the modern technologies used successfully.

The following factors are taken into account in developing the asset Health Index:

- Tank corrosion
- Condition of doors, door latches, locks and operating handle
- Condition of arc suppressors and interrupters
- Condition of grounding
- Condition of mounting base
- Condition of inter-phase barriers
- Presence of hot spots (Thermo vision scan)

Average life of pad mounted disconnect switches is approximately 40 years. Consequences of switchgear failure include customer interruptions, health and safety as well as environmental consequences.

2.4.10 Auto Transfer Switches

Transfer switches are designed to operate in several different configurations and controls can be generally configured to suit different operating scenarios. Open transition transfer switches are the simplest kind. They are mechanically interlocked to ensure that the power from one source is disconnected before the connection is made to the other source. The closed transition transfer switches eliminate momentary power interruption when both sources are present and synchronized, by transferring the loads with an overlapping contact arrangement. The soft load closed transition switch extends the overlap time to multiple seconds, for a smoother transition of load to the standby source.

The transfer switches are generally electrically operated and mechanically held and have auxiliary contacts for control circuits. Main contacts are commonly made of silver alloy to resist welding and sticking during load transfers. They are mounted either in ventilated or submersible enclosures depending on the installation location. Just like circuit breakers, the heavy duty switches are often equipped with arc chutes to extinguish switching arcs.

THESL employs 800A, 1000A,1600A, and 2500A rated transfer switches in mounted in below grade vaults inside submersible enclosures. The health degradations the transfer switch is subjected to include:

- contact wear,
- wear and tear of the mechanical operating mechanism,
- degradation of insulator supports and inter-phase barriers,
- corrosion of the switch tank,
- failure of the tanks seals allowing penetration of the moisture.

Since the primary purpose of transfer switches is to ensure high reliability for critical loads, it is imperative that any interruptions due to the failure of the switch itself be avoided. This is why the transfer switches should generally be maintained more frequently than other equipment.

The average life of transfer switch varies depending upon the number of actual operations and may vary from 25 to 30 years. Consequences of switchgear failure include customer interruptions and employee safety.

2.4.11 Primary Cables

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

The underground medium voltage feeders are commonly installed in loop or primary selective configurations to provide the level of reliability required. This allows the power supply to be restored thorough an automated or manual switching action, following a cable fault. The fault location and repairs are made after supply has been restored from the back-up supply. THESL's distribution's underground cables asset class consists of extruded XLPE insulated cable, PILC cable, and a small percentage of EPR cable. Underground cables in the suburban subdivisions are installed in direct buried configurations, except for road and railway crossings. Cables in the high density commercial areas are generally installed in ducts.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Underground cables are relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems unlike overhead lines, do not suffer from weather induced faults and have better reliability records. Faults on underground cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather

than the balance between and repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of relatively old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

PILC Cables

Generally, corrosion of metal sheath and degradation of the oil impregnated paper insulation cause degradation of the PILC cables. Instant failures may be caused through accidentally dig-ins, but these are generally repairable. Sheath corrosion may vary as a function of the original cable design, possibly sheath damage during installation, presence of corrosive soils in direct buried configurations or presence of corrosive flood water in ducts and the existence of corrosion due to stray dc current. Aging of paper insulation is a function of operating temperature and is dependent on cable loading during its life span as well as thermal conductivity of soils in which cables are installed. Surveys indicate that dielectric deterioration of oil impregnated paper insulation does not present significant end-of-life issues unless cables are subject to prolonged periods above their maximum allowable temperatures. Isolated sites of corrosion resulting in moisture penetration and isolated sites of dielectric deterioration resulting in insulation breakdown can both result in localized failures. However, if either of these conditions becomes widespread frequent cable failures will occur and the cable can be deemed at its effective end-of-life.

Condition information relating to either of these degradation processes is difficult to obtain. Generally, the only opportunity to obtain useful condition information is at the time of a failure and repair. Thus, examination and analysis of faulted sections can be an important condition assessment process. However, it is important to distinguish between condition related and non-condition related cable failures. External or third party damage is a major cause of failures, either immediately or at some time following the damage. If failure frequency is used as a measure of end-of-life, it is important to exclude these failures during the analysis.

Degree of sheath corrosion can be determined through microscopic examination of failed samples. Internal processes in paper insulation that lead to dielectric degradation involve localized discharge activity where impregnation is poor or has deteriorated, or where voids or discontinuities occur in cable fabrication. Thus, detecting, measuring and identifying the location of discharges in cables represent additional ways to assess condition. Discharge mapping using very low frequency (VLF) power supplies has been used over the past 10 to 15 years to assess cable condition. For short cable lengths (i.e., up to about 3 km), the technique not only can detect discharges, but also can locate them. In such cases, it is sometimes possible to identify and target replacement for individual sections of cables particularly at risk. While conventional cable discharge mapping involves an off-line test, permanent monitoring systems to measure discharge activity on line during normal operation are under development and available in prototype forms.

PILC cables have been known to provide long service life between 50 and 70 years.

Extruded Cross Linked Polyethylene (XLPE) Cables

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables,

their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

Polymeric insulation is very sensitive to discharge activity. Thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semicon layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable heath are:

- Number of failures per unit length of installation
- Age of Cables.

At this time, the realistic life expectancy of XLPE cables is difficult to ascertain. There is concern that these cables will have a shorter lifetime than the earlier paper insulated cables, but experience is still limited. The life expectancy of TRXLPE cables is considered in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability.

2.4.12 Distribution Transformers

It has been demonstrated that the life of the transformer’s internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers may, sometimes, need to be removed from service as a result of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transfer operating age and winding temperature profile

The consequences of distribution transformer failure are mostly reliability impacts and relatively minor. This is why most utilities run their distribution transformers for residential services to failure. However for larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts may be high; transformers may be replaced as the reach near the end of life, without actual failure. The average transformer life is expected to be approximately 40 years.

2.4.13 Cable Chambers and Vaults

Underground cable chambers come in different styles, shapes and sizes according to the location and application. For this analysis we identified only the broad categories depending on their use and type of construction. Precast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are cheaper to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems. Sidewalk vaults are most often located in or adjacent to pedestrian walkways.

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, manholes must withstand heavy loads associated with traffic in the street. When located in driving lanes, manhole chimney and collar rings must match street grading. Since manholes and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. However, environmental regulations may prohibit in some jurisdictions the pumping of manholes or vaults into sewer systems, without testing of water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Therefore, a condition-based asset management program based on periodic field inspections to identify problems and rate the condition of the structure is used by many utilities. Tracking the results of these inspections will show the rate of deterioration and provide advance notice of impending work to correct any problems. Some underground chambers may

only need cleaning or repairs on frames and covers or vault doors and grates, but the others may require major rebuilding of the walls and/or roof.

Manhole degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Manhole systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a manhole system. Similarly, manhole systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with manholes also requires evaluation in assessing the overall condition of a manhole system. In addition to the above, for equipment vaults, condition of ventilation grates and padlocks need to be considered in assessing overall health.

Condition of underground chambers is ranked by taking into account the following factors:

- Condition of Floors, walls and roof
- Existence of asbestos tapes
- Condition of cable racks
- Existence of flooding
- Condition of drain and sump pump etc
- Manhole dimensions and available working space
- IR scan of splices

Like other civil structures, EOL for underground chambers is based on economic comparison of capital vs repair costs. In some cases end-of-life for an underground structure may be spelled when the size of the chamber is commensurate with the changed use of the facility. Average life of underground chambers is of the order of 60 to 80 years.

2.5 The Health Index Method

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

When using the Health Index method it is important to understand the differences between defect management and reactive maintenance versus long-term asset degradation and asset condition assessment. Defects are usually well defined and associated with failed or defective components in the ancillary systems that affect operation and reliability of the asset well before its end-of-life. These defects do not normally affect the life of the asset itself, if detected early and corrected. Defects are routinely identified during inspection and dealt with by corrective maintenance activities to ensure continued operation of the asset.

Long-term degradation is generally less well defined and it is not easily determined by routine inspections. The purpose of asset condition assessment is to detect and quantify long-term degradation and to provide a means of quantifying remaining asset life. This includes identifying assets that are at or near end-of-life and assets that are at high risk of generalized failure that will require major capital expenditures to either refurbish or replace the assets.

A good understanding of the asset degradation and failure processes is vital if condition assessment procedures are to be effectively applied. It is important to identify the critical modes of degradation, the nature and consequences of asset failure, and, if possible, the time remaining until the asset is degraded to the point of failure. Unless there is a reasonable understanding of the degradation and failure processes, it is impossible to establish sensible assessment criteria or to define appropriate end-of-life criteria.

A composite Health Index is a very useful tool for representing the overall health of a complex asset. Transmission and distribution assets are seldom characterized by a single subsystem with a single mode of degradation and failure. Rather, most assets are made up of multiple subsystems, and each subsystem may be characterized by multiple modes of degradation and failure. Depending on the nature of the asset, there may be one dominant mode of failure, or there may be several independent failure modes. In some cases, an asset may be considered to have reached its end-of-life only when several subsystems have reached a state of deterioration that precludes continued service. The composite Health Index combines all of these condition factors using a multi-criteria assessment approach into a single indicator of the health of the asset.

For a typical asset class, a wide range of diagnostic tests and visual inspections may be undertaken, either as part of the ongoing maintenance program or as special-purpose Asset Condition Assessment (ACA) surveys. In some cases, a poor condition rating value will represent a failure of a subsystem, which can be repaired through replacement of that subsystem, with no resultant impact on the serviceability of the overall asset. However, it should be recognized that generalized deterioration of many or all of the subsystems that make up an asset can also be a valid indication of the overall health of the asset. A composite Health Index captures generalized deterioration of asset subsystems, as well as fatal deterioration of a dominant subsystem.

In developing a composite Health Index for an asset, it is very important to understand the functionality of the asset, and the manner in which the various subsystems work together to perform the key asset functions. With a clear understanding of asset functionality, condition ratings of different asset components and subsystems can be combined to create a composite "score" for the asset, and the continuum of asset scores can be subdivided into ranges of scores that represent varying degrees of asset health.

The critical objectives in the formulation of a composite Health Index are:

The index should be indicative of the suitability of the asset for continued service and representative of the overall asset health
The index should contain objective and verifiable measures of asset condition, as opposed to subjective observations
The index should be understandable and readily interpreted

Development of a condition-based Health Index requires an assessment of the relative degree of importance of the different condition factors in determining the health of the asset. Each condition factor must be assessed as falling into categories as shown in Table 2-3 below.

Table 2-3 Relative Degree of Importance of Condition Criteria

No impact	Indicator reflects defects or deterioration measures that have no impact on overall asset health. E.g. Silica gel in Transformers
Contributing Criteria	Indicator reflects defects or deterioration measures that range from low to high in importance, but typically in combination with other measures as part of a formulation of generalized deterioration. E.g. Contacts in Circuit Breakers.
Combinatorial Criteria	Indicator reflects a measure which does not represent asset condition in isolation, but is a critical component in a complex logical and/or mathematical formulation of asset health. E.g. Oil Quality Test in Transformers.
Dominant Criteria	Indicator reflects the health of dominant subsystem that makes up the asset, and end-of-life based on this single factor can represent end-of-life for the entire asset. E.g. DGA Test in Transformers or remaining strength in Wood poles.

By using a multi-criteria analysis approach, the various factors can be combined into an idealized condition- based Health Index. This involves grouping together the various factors, crafting the mathematical and/or logical formulations, and establishing the importance weightings of all the factors to allow combining them into a single Health Index.

Next a quantified scoring system can be developed to appropriately represent the asset health consistent with this philosophical approach. The steps are as follows:

1. "Deterioration" assessments or scores are converted to health scores in a defined range from "perfect health" to "end-of-life".
2. Importance weighting is assigned to each factor in a range from "modest importance" to "very high importance".

3. General deterioration index is formulated by calculating the maximum possible score by summing the multiples of steps 1 and 2 for each factor.
4. The general deterioration index is normalized to a maximum score of 100 based on having a defined acceptable/minimum number of condition criteria available.
5. Normalize the dominant factors to a maximum score of 100.
6. Calculation of the overall Health Index as the lesser of step 4 or 5, where 100% is excellent health and 0% is “poor” health.

Finally the continuum of asset health scores is correlated into discrete categories of asset health from “Very Poor” to “Very Good”. This conversion into discrete categories for a condition index requires fine-tuning of the health scoring system, since it is necessary that the relative degree of severity of the scores due to “dominant” factors and those due to generalized degradation match up at the boundaries between each category. This may require iteration of the individual steps to ensure that the resulting index is rational and coherent, and reasonably reflects field condition.

The next section explains in detail a typical Health Index formulation through the example of Station Transformers.

2.5.1 Station Transformer Health Index Example

The Health Index formulation developed for Transformers is explained in the text and tables below.

First Condition Criteria are developed for the asset class such as bushing condition or oil leaks. For purposes of formulating the Health Index, a particular piece of equipment is assessed and assigned a numeric value for each of the condition criteria. Numeric values of 1 to 5 were used in this study to have similar meanings to those used in THESL’s inspection forms. This assigned value for an asset was based on reviews of inspection records and diagnostic test reports extracted from THESL’s databases. For the Health Index method the THESL values were translated to factors from 0 to 4 as shown in Table 2-4 below.

Table 2-4 Condition Rating Factors and their Meaning

THESL Condition Rating	Factors	Interpretation
1	4	Component is in “As new” condition
2	3	Some minor problems or evidence of aging
3	2	Many minor problems or a major problem that requires attention – THESL category 3 equipment “Repaired during maintenance were mapped into this category
4	1	Many problems and the potential for major failure
5	0	Completely failed or is damaged/degraded beyond repair.

The components and tests shown in Table 2-5 below are weighted based on their importance in determining the transformer’s end-of-life. For example, those that relate to primary functions of the transformer or asset receive higher weights than those that relate to more ancillary features and functions.

The individual factors are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each transformer. Because of the importance of the DGA test, if any of the tests scored a “5”, then the Health Index was divided by 2.

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

Table 2-5 below shows the component/test condition criteria, weightings, condition ratings plus the total possible maximum score for each member of this asset class.

Table 2-5 Station Transformer Health Index Formulation

#	Station Transformers Condition Criteria	Weight	Condition Rating	Factors	Maximum Score
1	Bushing Condition	1	1,2,3,4,5	4,3,2,1,0	4
2	Oil Leaks	1	1,2,3,4,5	4,3,2,1,0	4
3	Main Tank/Corrosion/Paint	1	1,2,3,4,5	4,3,2,1,0	4
4	Transformer Gaskets	1	1,2,3,4,5	4,3,2,1,0	4
5	Barriers	1	1,2,3,4,5	4,3,2,1,0	4
6	Grounding	1	1,2,3,4,5	4,3,2,1,0	4
7	Foundation/Supporting Steel	1	1,2,3,4,5	4,3,2,1,0	4
8	Secondary Connections/Primary Terminations/IR Scan	2	1,2,3,4,5	4,3,2,1,0	8
9	Overall Power Transformer	2	1,2,3,4,5	4,3,2,1,0	8
10	DGA Oil Analysis*	4	1,2,3,4,5	4,3,2,1,0	16
11	Age	4	1,2,3,4,5	4,3,2,1,0	16
12	Oil Quality Test	3	1,2,3,4,5	4,3,2,1,0	12

Max Score= 88, HI = 100*Score/Max.
*In the case of a condition rating of 5, overall Health Index is divided by 2

This Health Index formulation is based upon a combination of industry best practice formulation as well as the availability of data at THESL for the purpose of this study. THESL may want to consider adding few criteria into their inspection and testing program for a true best practice Health Index formulation. These are criteria such as:

Furan Oil Test (Would be substituted for the age criteria, however only recommended for large and important transformers, also as a second tier test on suspect transformers)
Doble Winding Test (THESL is already performing this test but results need to be analyzed)

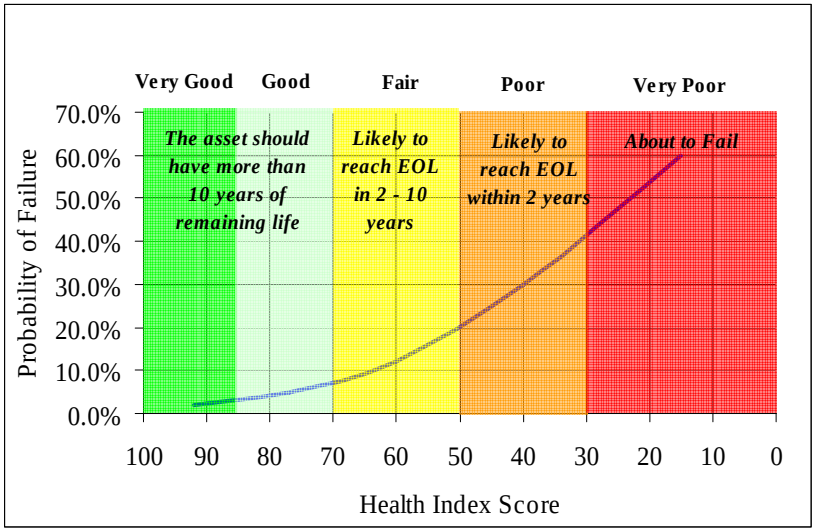
After performing all of the steps described above, the Health Index scale shown in Table 2-6 is used to determine the overall condition of the station transformer asset class.

Table 2-6 Health Index Scale for Station Transformers

Health Index	Condition	Description	Expected Lifetime	Requirements
85 – 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 15 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	More than 10 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 3 – 10 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 3 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

This assessment of when this asset is expected to reach end-of-life (EOL) along with probabilities of failure can also be illustrated in Figure 2-1 below. This is based on an engineering judgment with the backing of some failure statistics from other utilities and once more data becomes available this curve can be assessed more accurately and similarly developed for other asset groups.

Figure 2-1 Estimating Probability of Failure from the Health Index



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3 ANALYSIS OF ASSETS

The asset condition was analyzed primarily on the basis of Health Indexes. Where the data was insufficient, either in quantity or quality, to provide an accurate Health Index, then the condition assessment was estimated based on available information such as equipment age, or maintenance history.

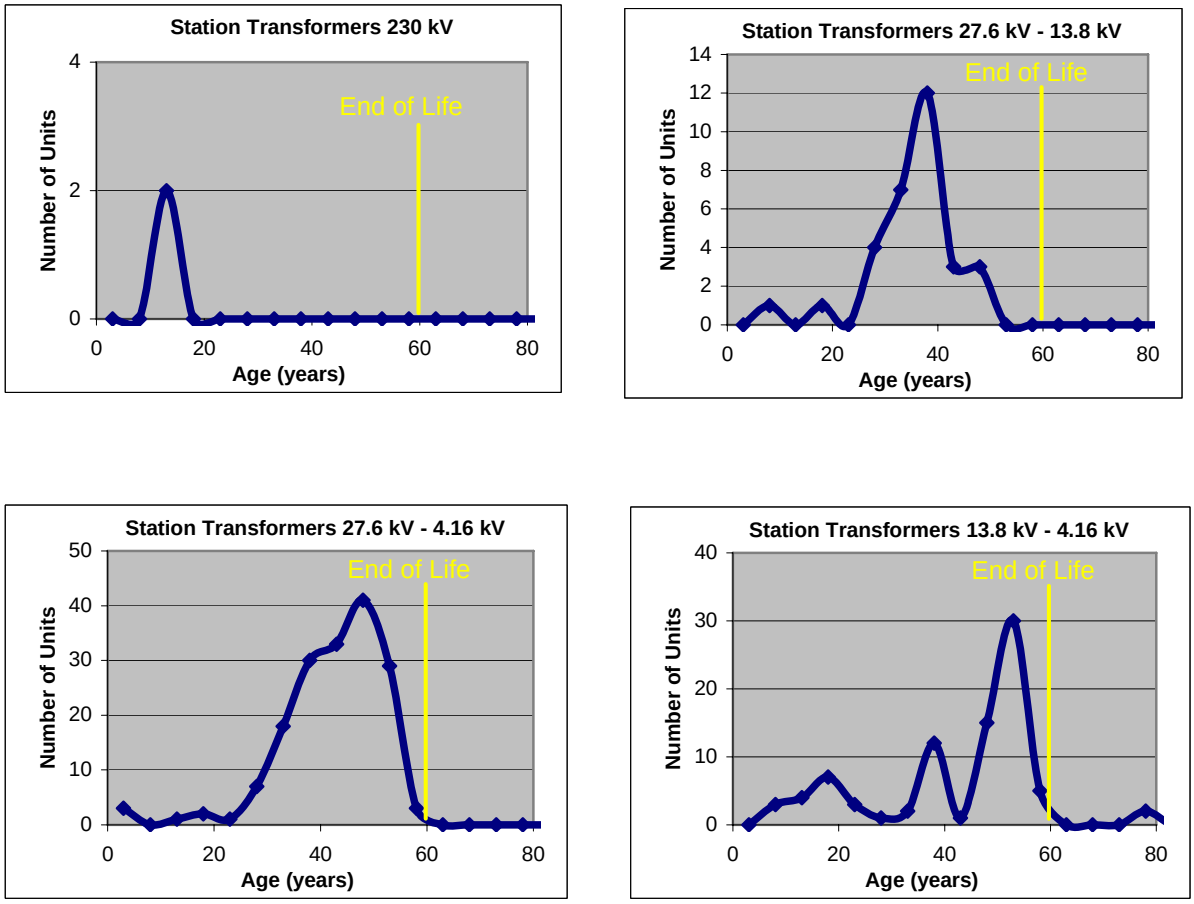
The end-of-life points (yellow line) marked on the age distribution figures in this section represent the typical age at which a component should be removed from the system and replaced for no other reason than it has reached the defined end of life. It does not represent the average age at which components are removed, which can be significantly less due to a number of other factors. It also does not indicate that a particular component of this age should be removed, if it is in good condition. Some of THESL's previous work will agree with the end-of-life on the age distribution figures while others, based upon average replacement age, will have lower end-of-life figures.

The total number of assets in the Health Index results or in the age distributions do not always match the total number of assets in service because of limitations in the available data. In these cases the conclusion at the end of each section on the total number of assets that will require replacement has been scaled to the total number in service.

3.1 Station Transformers

There are a total of 287 power transformers in active service on the THESL system, 2 at 230-27.6 kV, 34 at 27.6-13.8 kV, 166 at 27.6-4.16 kV and 85 at 13.8-4.16 kV. Each of these transformers supplies energy to a large number of customers and their continued operation is critical to meeting service requirements. For this reason they have always been a key asset for condition assessment and planned replacement. Historically they have been very reliable and have remained in service for up to 60 years. The present age distributions of these power transformers are shown in the Figure 3-1.

Figure 3-1 Age Distribution of Station Transformers



The expected lifetime of a power transformer is very dependent on how heavily it is loaded and for how long. It also depends on the design of the transformer, the quality of manufacture and its operating environment, particularly the number and severity of through faults. The yellow line indicating end of life in Figure 3-1 has historically been the typical average in the industry but it is not accurate for individual units. For these reasons age alone is not a good indicator of power transformer condition.

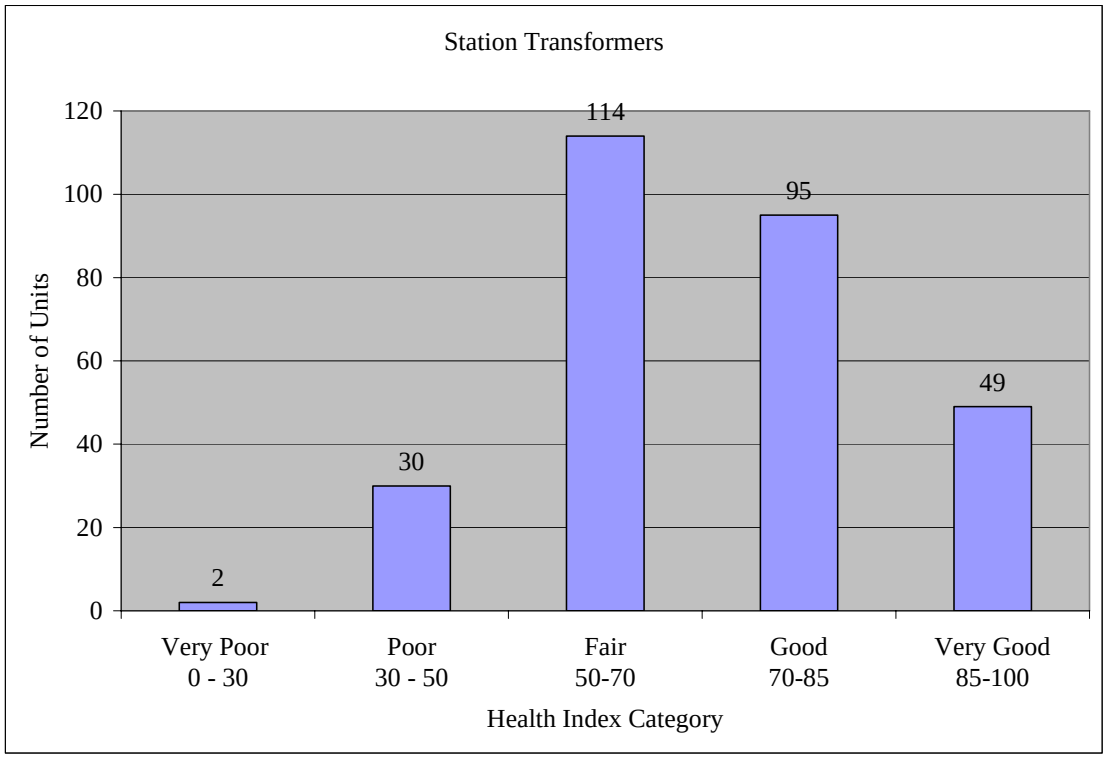
Health Indexes have been computed for all of the THESL power transformers based on the results of condition assessment tests and the results are presented in Table 3-1 and Figure 3-2.

Table 3-1 Summary of Condition Rating Results for Station Transformers

Condition Ratings: Station Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing Condition	1	9	0	0	0	10
Oil Leaks	0	9	0	0	0	9
Main Tank/Corrosion/Paint	0	8	0	0	0	8
Overall Condition/Other	217	36	15	7	0	275
DGA Analysis	187	62	23	2	16	290
Oil Quality Test	128	44	32	0	86	290
Age	29	91	168	2	0	290

The number of units in the “Very Poor” Health Index category indicates the number that should be replaced in the next year. The units in the “Poor” category are expected to require replacement in the following two years, and those in the “Fair” category in sometime in years 4 to 10.

Figure 3-2 Summary of Condition Assessment Results for Station Transformers

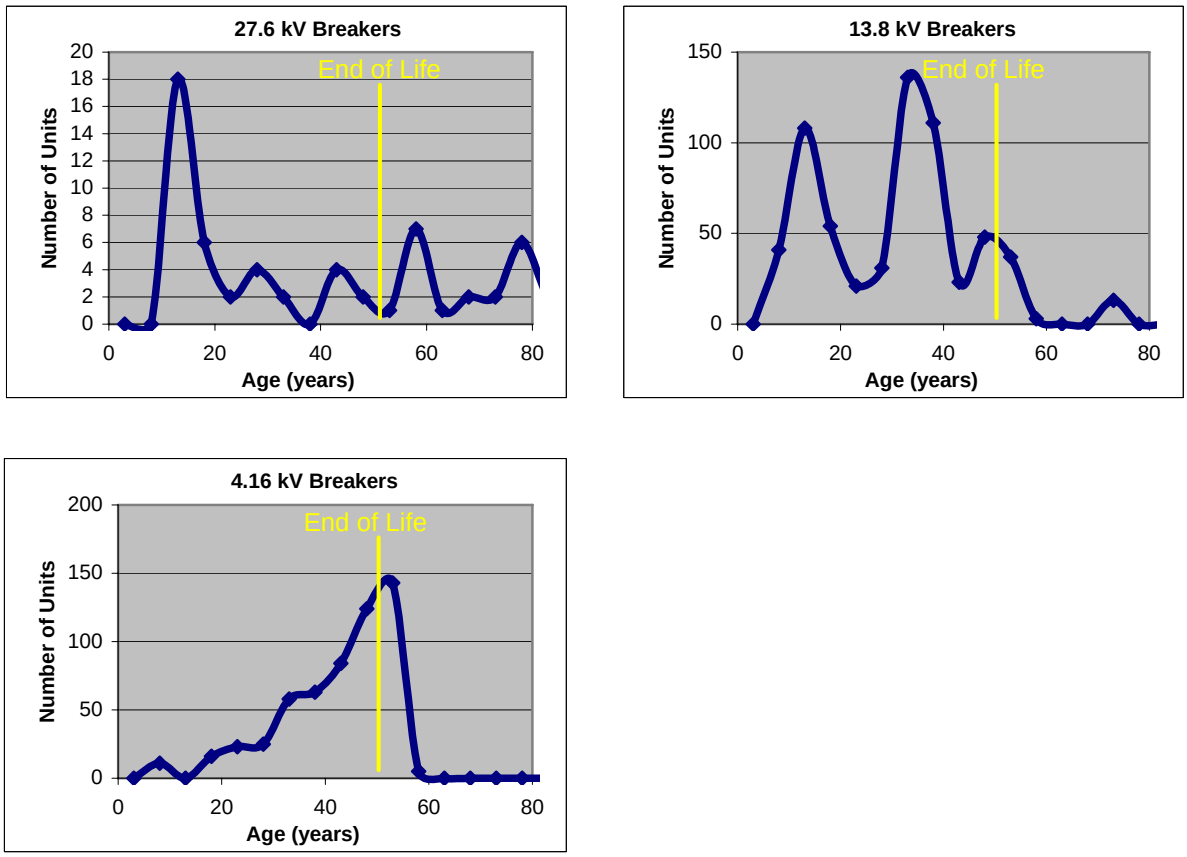


3.2 Circuit Breakers

The circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Distribution circuit breakers at THESL are commonly used at transmission or distribution stations for switching 27.6, 13.8 or 4.16 kV feeders. There are 120 27.6 kV breakers, 743 at 13.8 kV and 869 at 4.16 kV. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breakers designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers, vacuum breakers, magnetic air circuit breakers and SF6 circuit breakers.

The present age distributions of the circuit breakers at THESL are shown in the Figure 3-3.

Figure 3-3 Age Distribution of Circuit Breakers



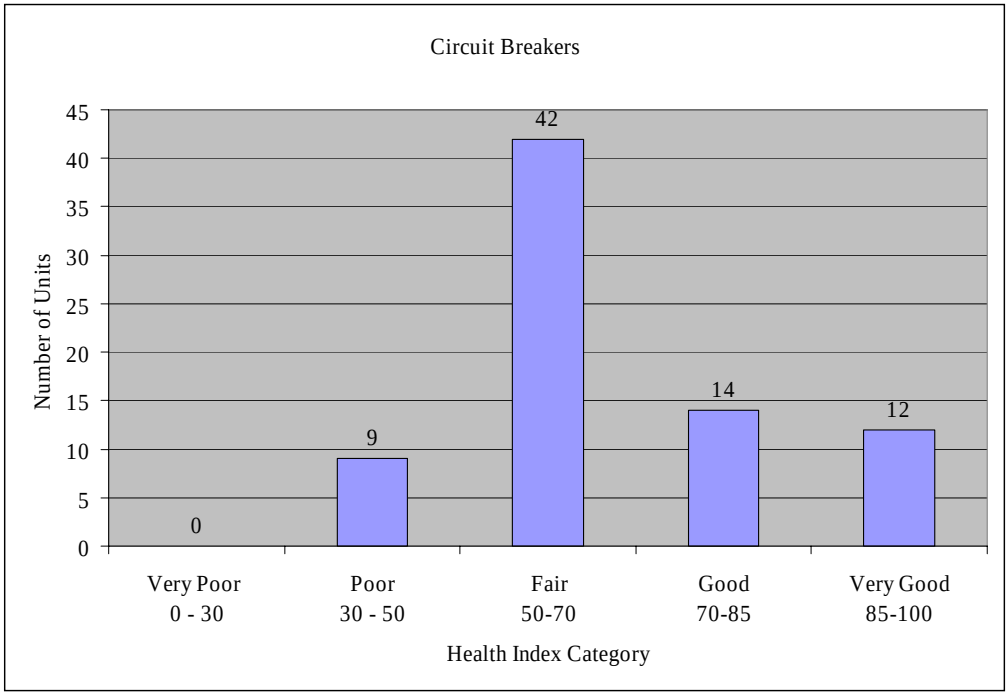
Circuit breakers are a very maintainable component. All of the parts that wear out with use, such as contacts, bearings, springs, can be replaced. The yellow end-of-life lines on Figure 3-3 are typical for the industry but they cannot be applied to individual units. The amount of maintenance circuit breakers require depends on how often they are called upon to interrupt faults and how severe the faults are, but their end of life is more often brought on by changes in the system that make their interrupting capability inadequate or by the unavailability of replacement parts. Age is not a good condition indicator for circuit breakers and cannot be used to estimate the number that will need to be replaced in the next ten years.

A Health Index has been defined for circuit breakers but the available data was not sufficient to create a Health Index that was representative of the population at this point in time. Only 10.8% of the units had sufficient data to calculate the Health Index and this was not random over the different types of breakers.

Table 3-2 Summary of Condition Rating Results for Circuit Breakers

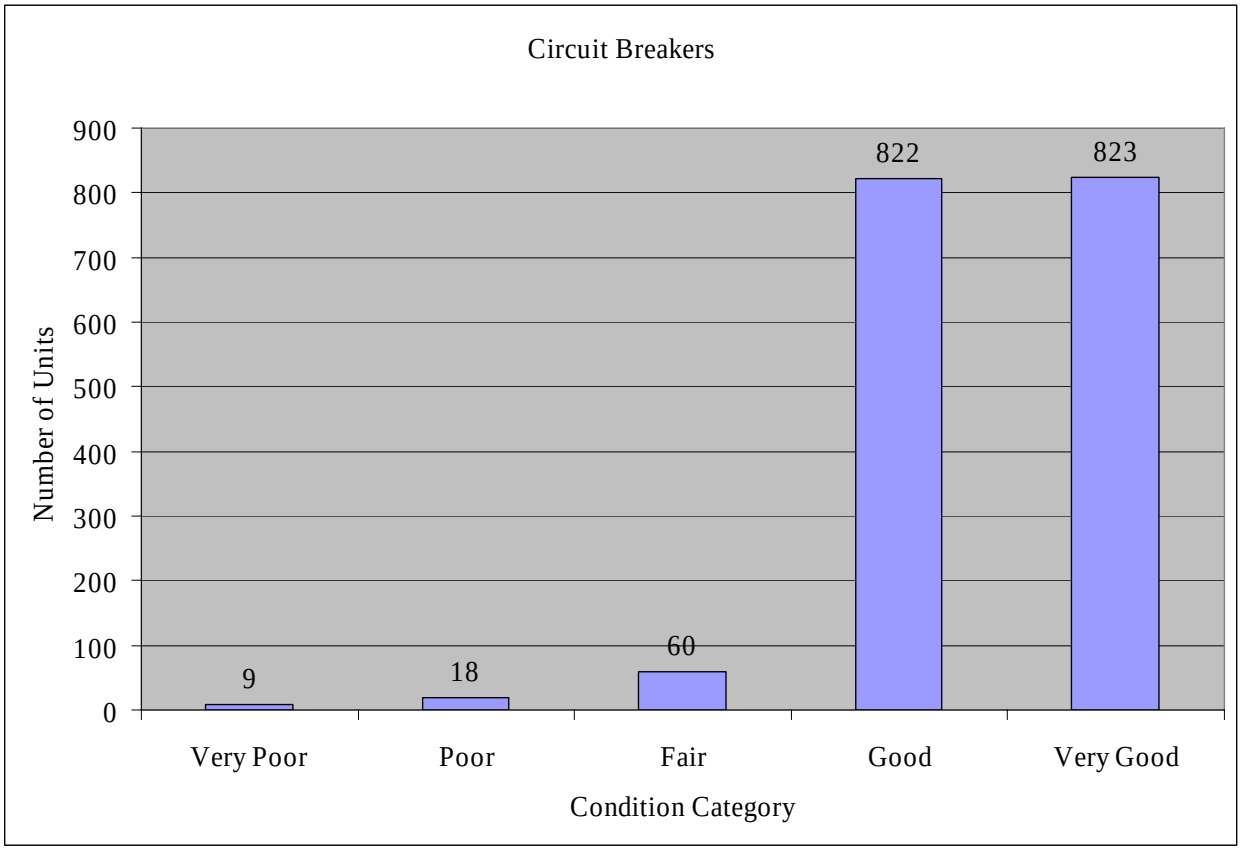
Condition Ratings: Circuit Breakers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Contact Resistance	41	26	9	1	0	77
Overall Condition	22	55	0	0	0	77
Age	15	2	16	14	30	77

Figure 3-4 Summary of Health Index Results for Circuit Breakers



Since age is not a preferred indicator of remaining life for circuit breakers, and the data for the Health Index was insufficient, an estimate must be based on historical trends. In interviews with staff the main issue seemed to be that the older breakers were obsolete, had few sources for replacement parts and in some cases were deteriorating faster than the rate of replacement. Taking this into account it is recommended that THESL plan on replacing 5% of the breakers over the next ten years. This replacement rate reflects 9 breakers in very poor condition, 18 in poor condition and 60 in fair condition, as shown in Figure 3-5.

Figure 3-5 Summary of Condition Assessment Results for Circuit Breakers

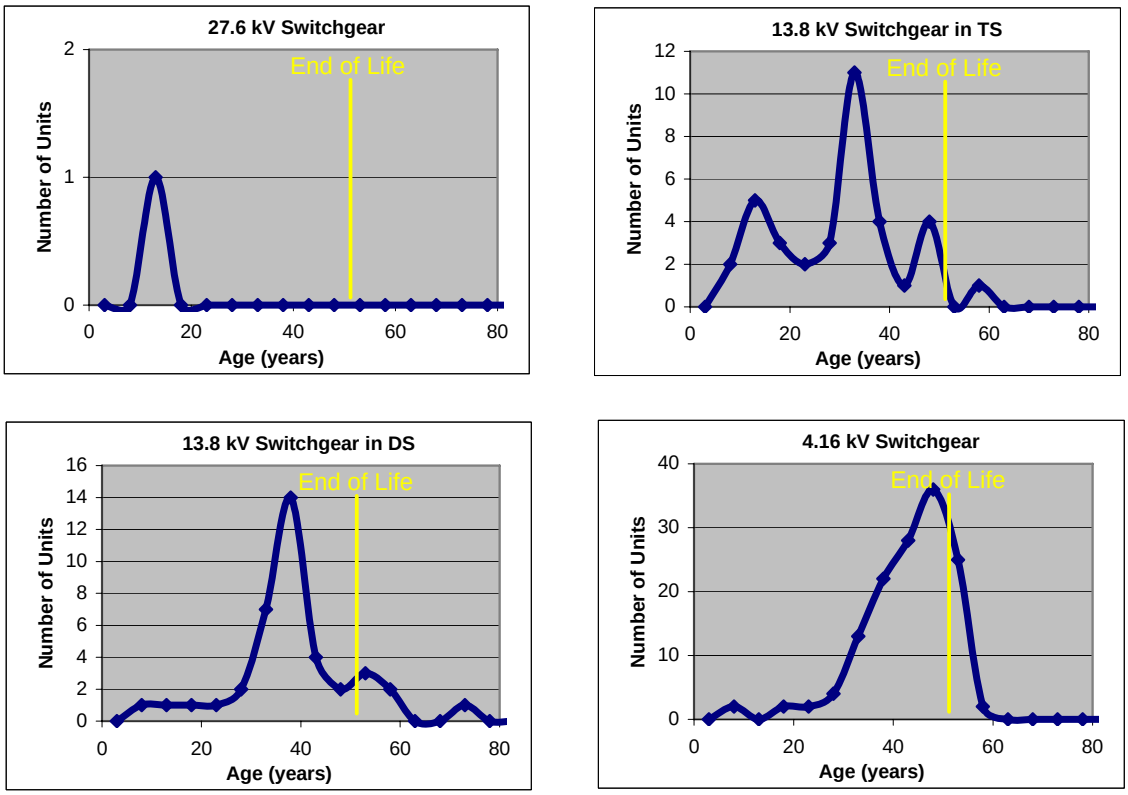


3.3 Switchgear

This asset covers the metal clad switchgear commonly employed at substations. Metalclad switchgear typically consists of an assembly of retractable/racked switching, metering and protection and control devices that are totally enclosed in a metal envelope. The switchgear comes in standard MV operating voltage ratings and includes busbar, circuit breakers, disconnect switches, fuses, protection and auxiliary relays, instrument transformers, metering devices etc. The gear is modular i.e. each breaker is enclosed in its own metal envelope (cell). The gear is also compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and busbars associated with each cell.

The present age distribution of switchgear is shown in Figure 3-6.

Figure 3-6 Age Distribution of Switchgear



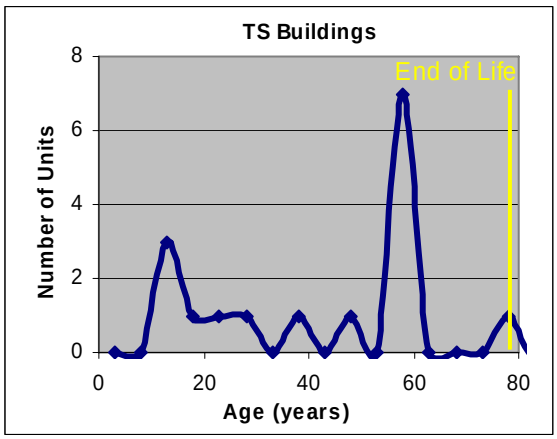
Although a Health Index for switchgear has been formulated, there was insufficient existing data available for the input condition monitoring parameters. A Health Index will be computed for switchgear when the data becomes available.

Switchgear, like circuit breakers, are very maintainable. The age alone is a poor indication of end of life. The annual maintenance expenditure that produces the lowest long term cost for switchgear is quite high because the capital replacement cost is very high. The best long term strategy is therefore to maintain these assets rather than replace them. The amount of required replacement in therefore estimated to be very low, at 1% (3 of the total 272 units) over the next ten years.

3.4 Buildings

Buildings at major terminal stations house the switchgear, relays and controls. This asset includes foundations, walls, roof, doors and windows, plumbing and wiring, and grounds.

Figure 3-7 Age Distribution for TS Buildings



Buildings are another very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life.

Although a Health Index for buildings has been formulated there is no available data for the input condition monitoring parameters. The data collected in the past has been oriented towards identifying maintenance requirements rather than towards predicting end-of-life.

Although there is one building that is approaching 80 years old, there are no indications that it will need to be replaced in the next ten years.

3.5 Network Transformer/Protector Units

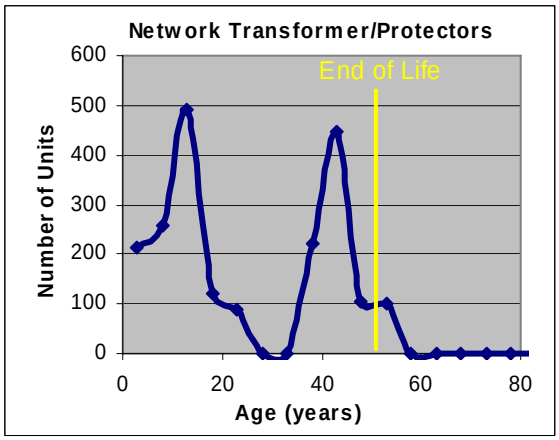
Network transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers of similar characteristic. THESL employs network transformers in two distinct applications, the first type supplying grid network with low voltage of 208Y/120 V and the second supplying spot network with low voltage of 416Y/240 V and 600Y/347 V. The grid network transformers come in standard ratings of 500kVA, 750 kVA and 1000 kVA. The spot network transformers can range in nameplate rating from 500 kVA to 1500 kVA. The primary winding of the transformers is connected in Delta configuration while the secondary is in grounded star configuration. The network transformers are provided with a primary disconnect, which has no current interrupting rating and is used merely as in isolating device after the transformer has been de-energized both from primary and secondary source. The secondary bushings are mounted on the side wall of the transformer in a throat, suitable for mounting of the network protector.

Network protectors are special purpose low voltage air circuit breakers, designed for successful parallel operation of network transformers. Network protectors are fully self contained units, equipped with protective relays and instrument transformers to allow automatic closing and

opening of the protector. The relays conduct a line test before initiating close command and allow closing of the breaker only if the associated transformer has the correct voltage condition in relation to the grid to permit flow of power from the transformer to the grid. If the conditions are not right, protector closing is blocked. The protector is also equipped with a reverse current relay that trips if the power flow reverses from its normal direction, i.e. if the power flows from grid into the transformer.

The present age distribution of network transformer/protector units is shown in Figure 3-8.

Figure 3-8 Age Distribution of Network Transformer Protectors

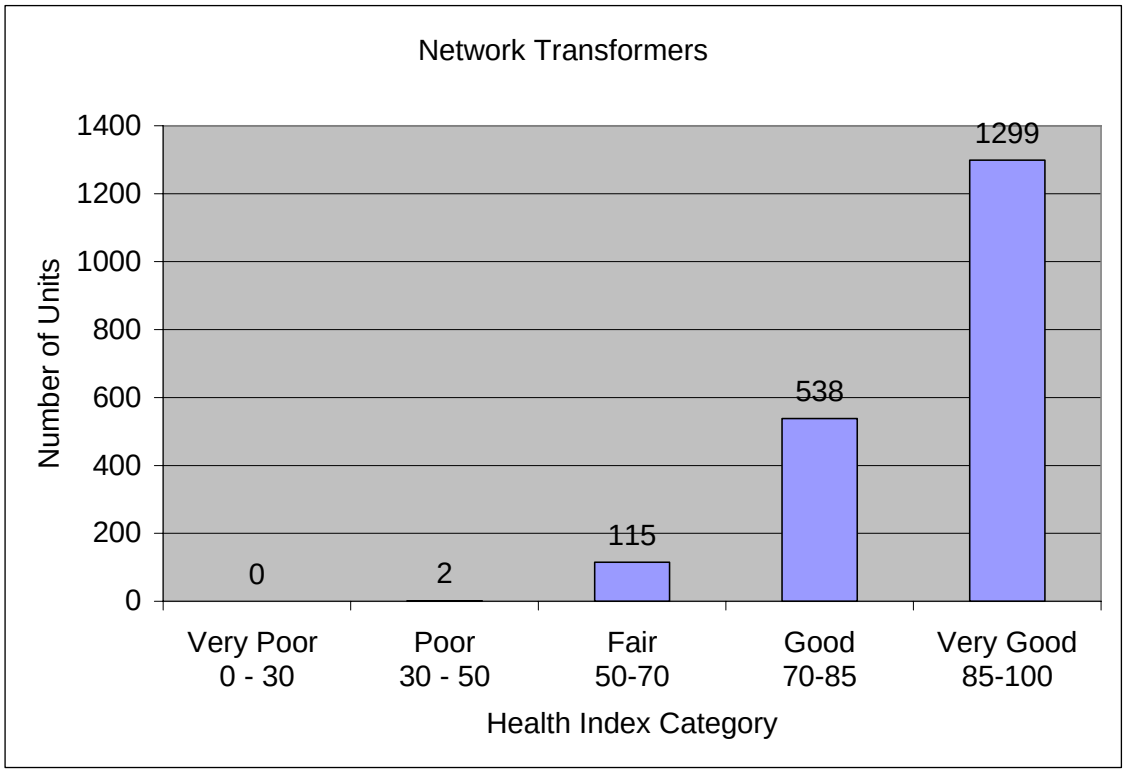


Health Indexes have been computed for the network transformer/protector units as described in Table 3-3 and Figure 3-9.

Table 3-3 Summary of Condition Rating Results for Network Transformers

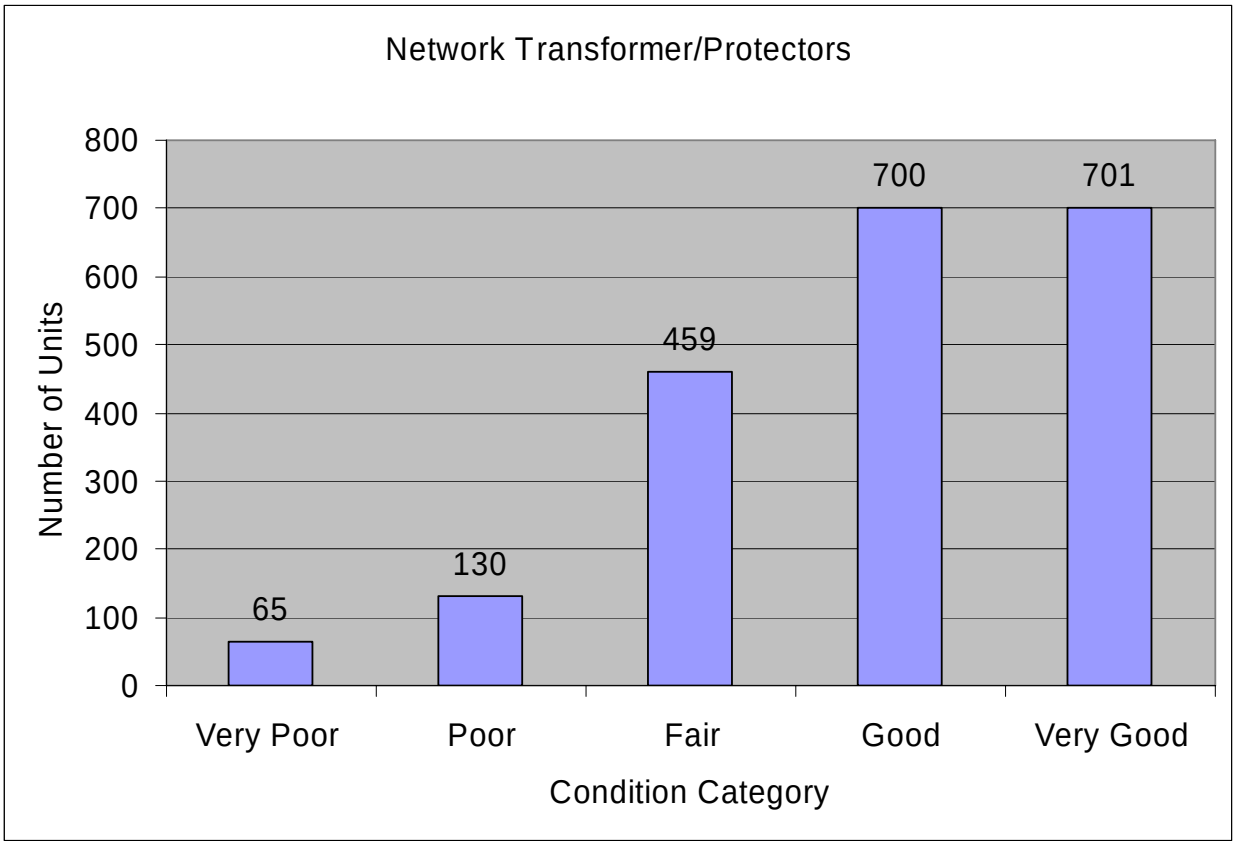
Condition Ratings: Network Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	1545	24	0	10	0	1579
Oil Leaks	1267	143	0	43	0	1453
Corrosion/Paint	1381	309	1	20	0	1711
Transformer Lid Gaskets	1478	134	367	29	0	2008
Dirt/Debris/Contamination	185	1	6	0	0	192
Pothead Termination	1945	40	2	11	0	1998
Overall Condition/Other	91	3	0	0	0	94
Switch Unit	1793	45	126	2	0	1966
Age	791	436	377	201	212	2017

Figure 3-9 Summary of Health Index Results for Network Transformers



The Health Index calculates that only 117 of the 1952 units assessed by the Health Index will need to be replaced over the next ten years, or 6% of the total population. An estimate based strictly on age, from Figure 3-5, indicates that 654 units will need to be replaced; or 32% of the total 2,055 units in service. Historically THESL has replaced about 60 units per year. Unexpected failures have been experienced with some designs and locations. Due to a concern that the Health Index formulation may need adjustment, it is recommended that the estimate based on age and historical trends be used. This indicates that 65 units are in very poor condition, 130 are in poor condition and 459 are in fair condition. The condition assessment is shown in Figure 3-10.

Figure 3-10 Summary of Condition Assessment for Network Transformer/Protectors

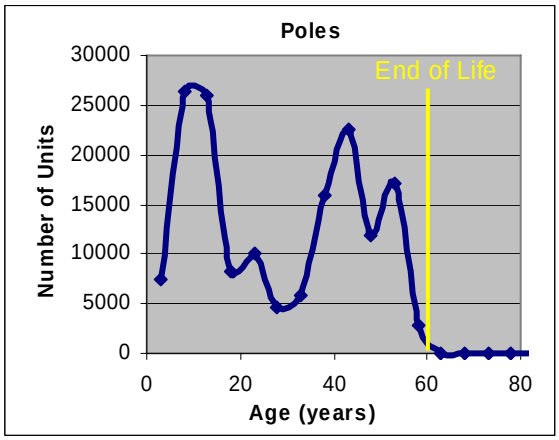


3.6 Poles

Wood poles are the most common form of support for medium voltage overhead feeders as well as LV lines. While a vast majority of the poles at THESL are wood poles, a significant number of concrete poles are also in use.

The present age distribution of wood poles is shown in Figure 3-11.

Figure 3-11 Age Distribution of Wood Poles

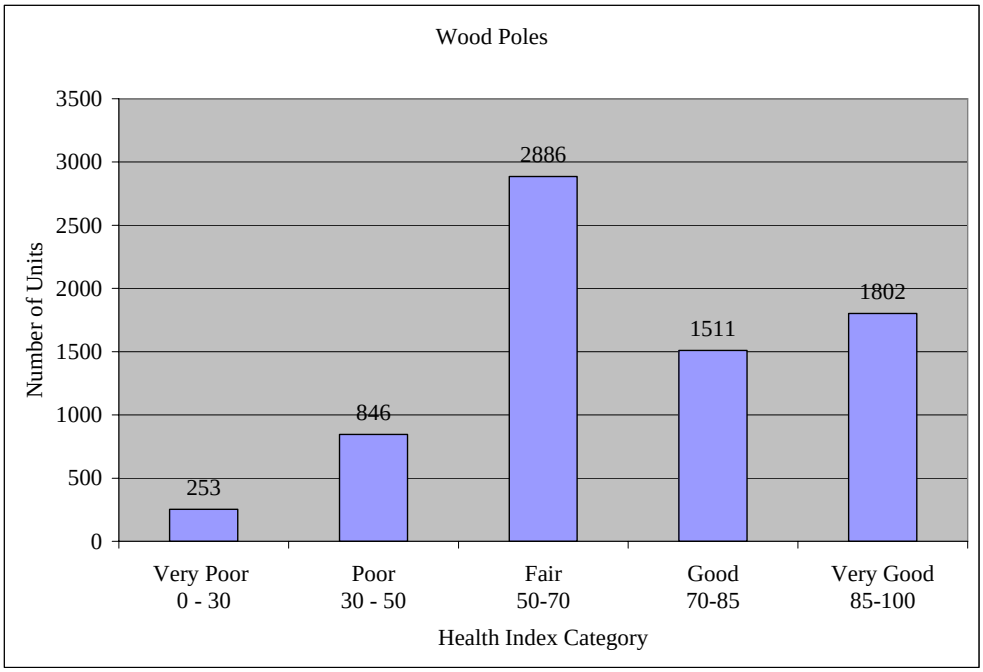


Health indexes have been computed for the wood poles as described in Table 3-4 and Figure 3-12.

Table 3-4 Summary of Condition Rating Results for Wood Poles

Condition Ratings: Wood Poles						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Overall Condition	2888	0	4800	250	233	8171
Remaining Strength	4579	1315	1159	139	106	7298
Cross Arm Condition	8063	116	11	0	2	8192
Damages (Moderate, Extensive):						
Cracks	-	-	3031	-	70	3101
Wood Pecker/ Carpenter Ant Damage	-	-	43	-	58	101
Surface Rot At/Below/Above Ground Level	-	-	553	-	40	593
Pole Top Feathering	-	-	2342	-	109	2451
Mechanical Fire Damage	-	-	13	-	2	15
Wood Loss	-	-	111	-	5	116
Other Criteria (Loose Shell, Soft Wood etc)	-	-	0	-	0	0

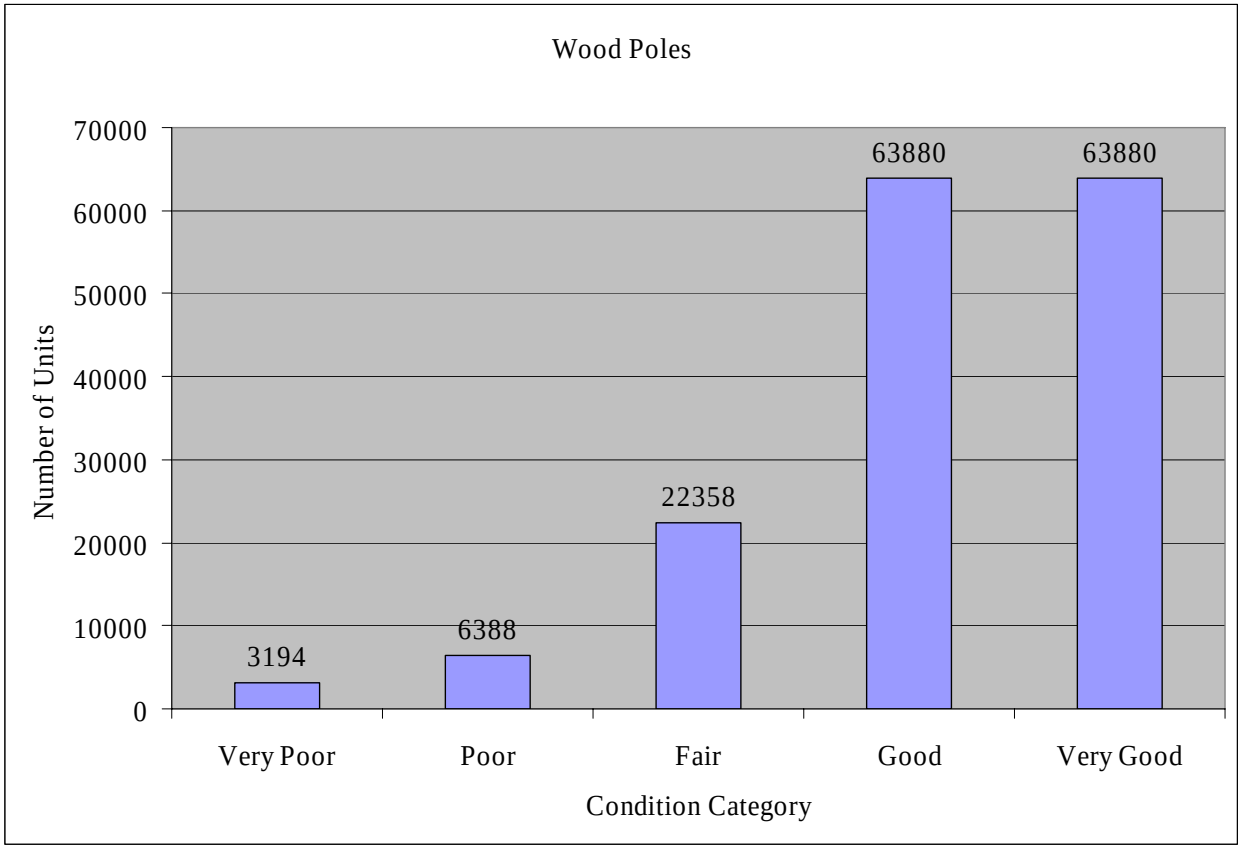
Figure 3-12 Summary of Health Index Results for Wood Poles



Input data for the wood pole Health Index was only available from one geographic area (Etobicoke). There are indications from maintenance records on the number of pole replacements that this area is not representative of the other areas of the service territory. Therefore, at the present time and until more data is available, the Health Index results must be interpreted carefully.

The best estimate of the number of poles that will need to be replaced has therefore been based on the age distribution. This indicates that 32,000 poles will need to be replaced in the next 10 years. The age based condition estimate is shown in Figure 3-13.

Figure 3-13 Summary of Asset Condition for Wood Poles



3.7 Remote Operated Overhead Switches

This asset class consists of overhead line load break, three-phase gang operated switches, that are capable of being operated from the control centre. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. They consist of the switch itself, a motorized operator, voltage and current sensors and communication equipment.

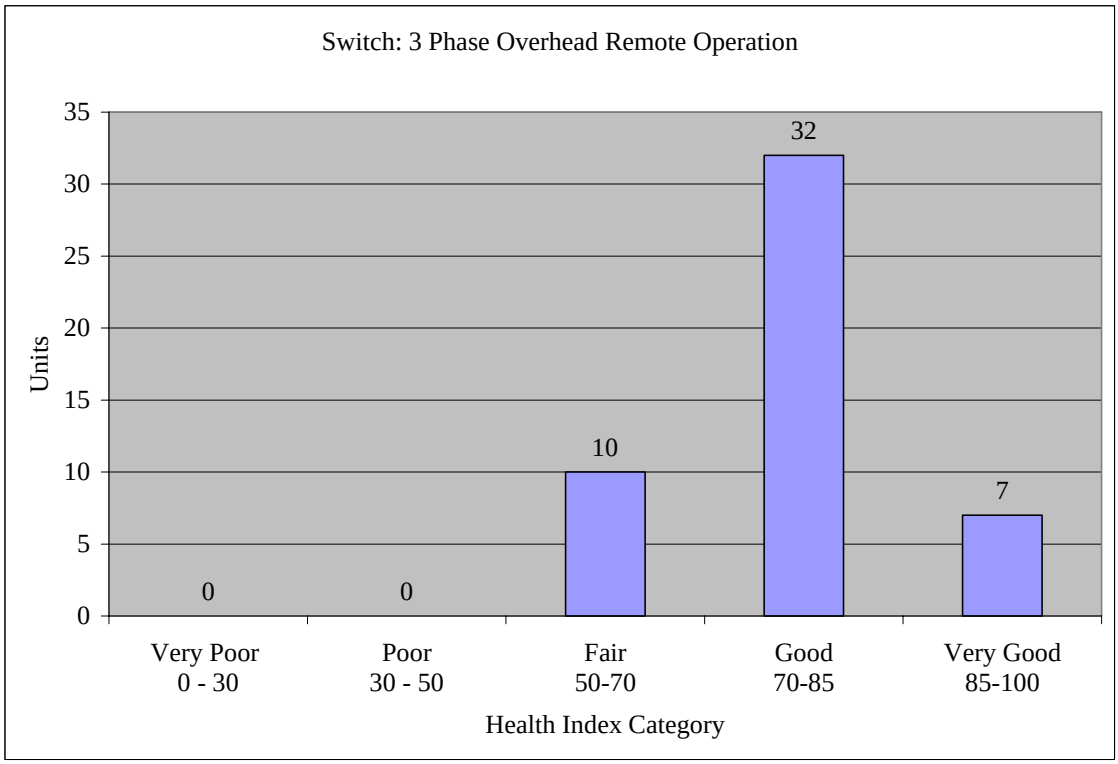
There was no age distribution data available for the remotely operated overhead switches.

Health indexes have been computed for the remotely operated overhead switches as described in Table 3-5 and Figure 3-14.

Table 3-5 Summary of Condition Rating Results for Remote Operated Overhead Switches

Condition Ratings: Remote Operated Overhead Switches						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Blade/Arm/Mounting	9	41	0	1	0	51
Connections/Terminations	9	39	0	1	0	49
Arc Suppressors/Interrupters	9	39	0	1	1	50
Grounding/Shunt Contact	8	42	0	1	0	51
Lock/Handles	7	43	0	0	0	50
Switch Insulator	9	36	1	4	0	50
Mechanism	4	20	0	0	0	24
Operations	3	19	0	0	0	22
Remote Open/Close Operation	143	15	1	7	0	166

Figure 3-14 Summary of Condition Assessment Results for Remote Operated Overhead Switches



The Health Index could only be computed for 49 of the 505 remotely operated overhead switches because of lack of data. It indicates that no remotely operated overhead switches will need replacement in the next three years and 103 in the seven years after that, if the Health Index results are extrapolated to the entire population.

3.8 Manual Operated Overhead Switches

This asset class consists of overhead line load break, three-phase gang operated switches, manually operated. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements.

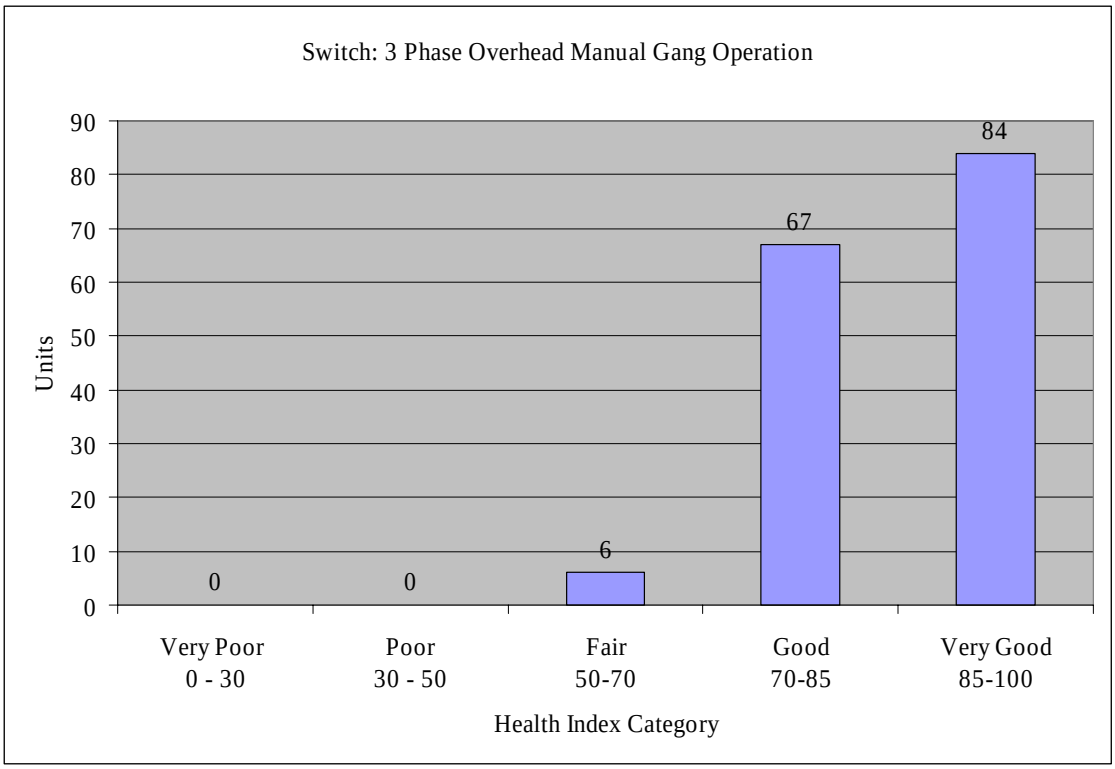
There was no age distribution data available for the manually operated overhead switches.

Health indexes have been computed for the manually operated overhead switches as described in Table 3-6 and Figure 3-15.

Table 3-6 Summary of Condition Rating Results for Manual Operated Overhead Switches

Condition Ratings: Manual Operated Overhead Switches						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Blade/Arm/Mounting	86	70	1	3	0	160
Connections/Terminations	81	66	1	4	0	152
Arc Suppressors/Interrupters	82	66	2	2	1	153
Grounding/Shunt Contact	86	68	2	1	0	157
Lock/Handles	67	67	1	22	0	157
Switch Insulator	85	64	1	3	1	154
Mechanism	3	3	0	0	0	6
Operations	2	5	0	0	0	7

Figure 3-15 Summary of Condition Assessment Results for Manual Operated Overhead Switches



The Health Index could only be computed for 157 of the 946 manually operated overhead switches because of limitations in the available data. It indicates that no manually operated overhead switches will need replacement in the next three years and 36 in the seven years after that, if the Health Index results are extrapolated to the entire population.

3.9 Pad Mounted Switches

This asset class consists of pad-mounted and above grade switchgear. A majority of the pad mounted switchgear currently in use employs air-insulated gang-operated load-break switches. The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures, ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism or degradation of insulated barriers.

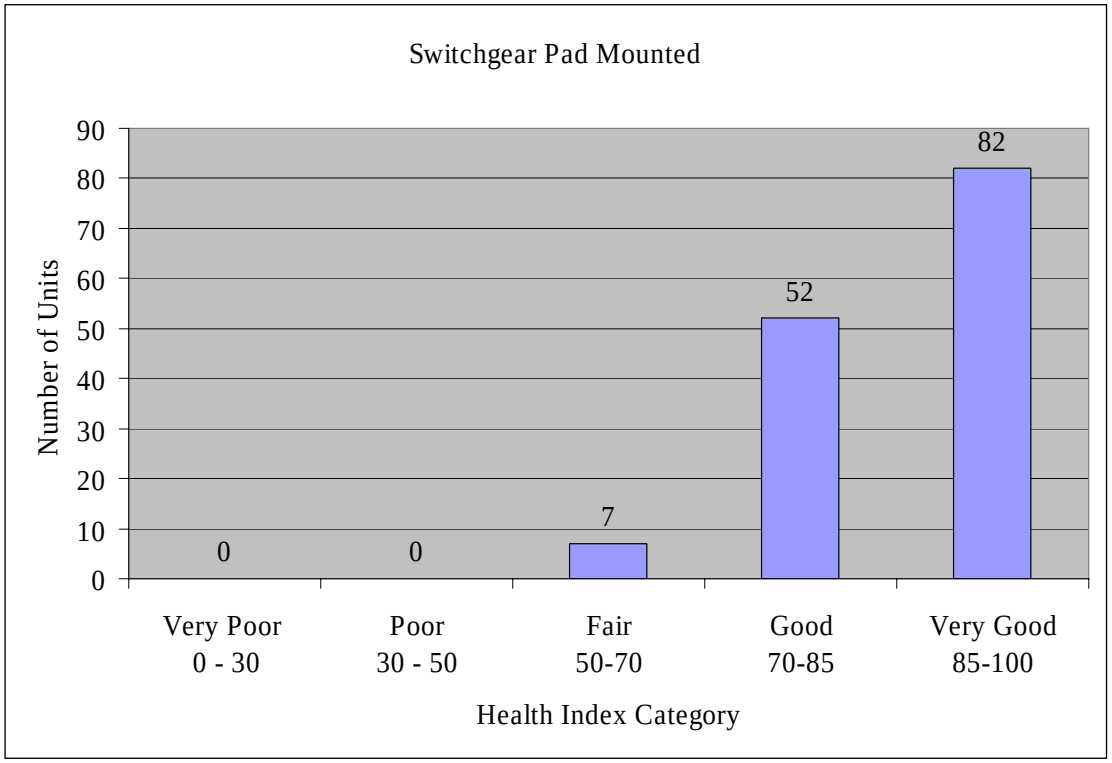
There was no age distribution data available for the pad mounted switches.

Health indexes have been computed for the pad mounted switches as described in Table 3-7 and Figure 3-16.

Table 3-7 Summary of Condition Rating Results for Pad Mounted Switchgear

Condition Ratings: Pad Mounted Switchgear						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Latches/Handles/Locks/Door	166	97	10	5	0	278
Grounding/Bonding	171	103	0	24	0	275
Corrosion/Paint	146	84	24	25	0	279
Concrete Base	0	0	0	0	0	0
Barriers	162	77	4	4	0	247
Arc Suppressors/Interrupters	70	65	0	0	1	136
Hot Spot in IR Scan	176	35	0	0	0	211
Age	33	47	3	0	0	83

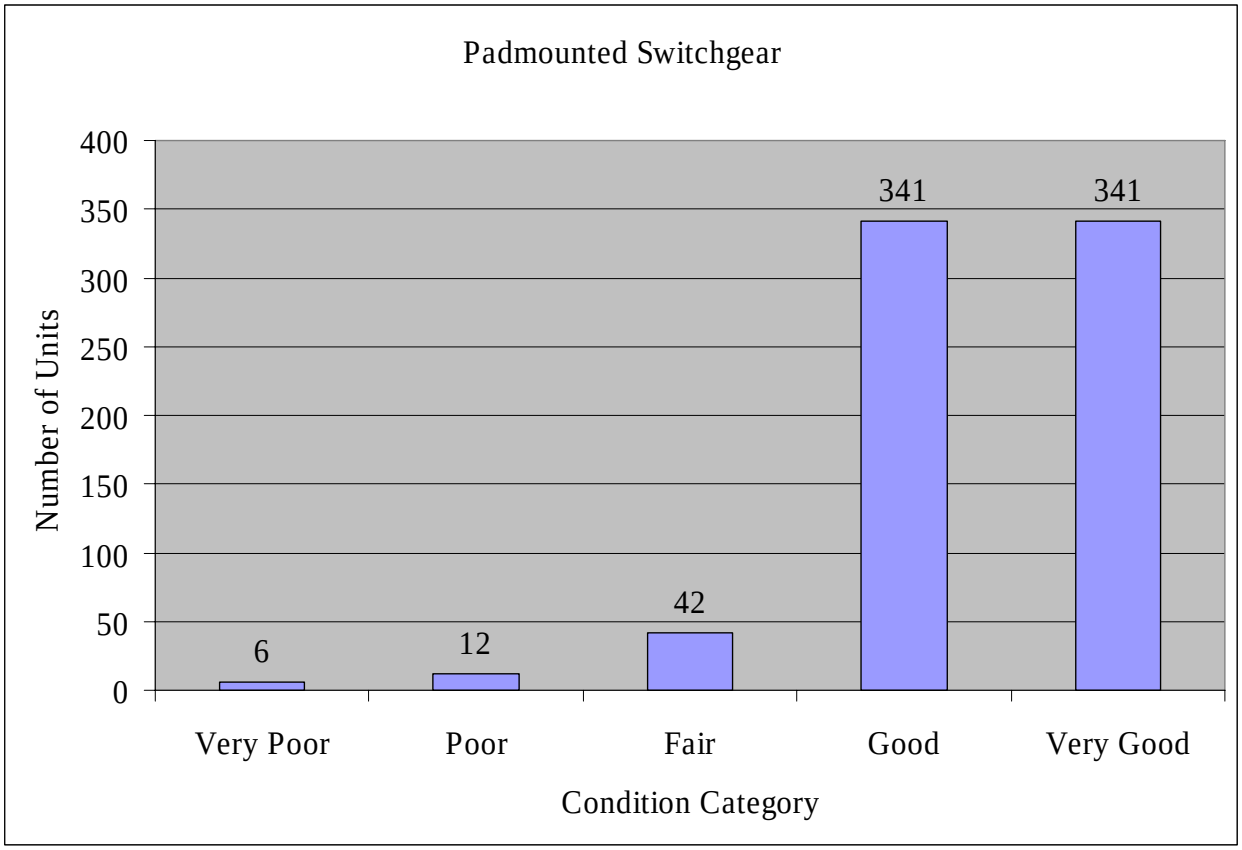
Figure 3-16 Summary of Health Index Results for Pad Mounted Switchgear



The Health Index results show that there are no pad mounted switches that should need replacement in the next three years and only 5% (37 units) in years 4 to 10. However, the field audit of condition determined that the average condition of pad mounted switches was worse than indicated by the Health Index. In interviews with maintenance staff concerns about pad mounted switches were noted. Padmounted switchgear populations are generally over 25 years old and have been experiencing a notable increase in electrical flashovers, particularly when installed near roadways. CO_2 washing has been used on these units, but there seems to be little correlation between failures and maintenance. Operators indicate that that PMH gear is responsible for 2 or 3 failures per year, but in a total population of 742 units this is not a high failure rate.

Given the mixed results, the Health Index formulation is being reviewed and it is recommended that THESL plan on replacing 6 units each year. This would indicate 6 units in very poor condition, 12 units in poor condition, and 42 units in fair condition as shown in Figure 3-17.

Figure 3-17 Summary of Asset Condition for Padmounted Switchgear



3.10 Automatic Transfer Switches

THESL employs auto transfer switches on the low voltage system for automatic transfer of power from preferred to standby source, when power from the preferred source is lost, either during a planned shutdown or during a forced interruption. When power comes back on the preferred feeder, the transfer switch switches back to the normal position.

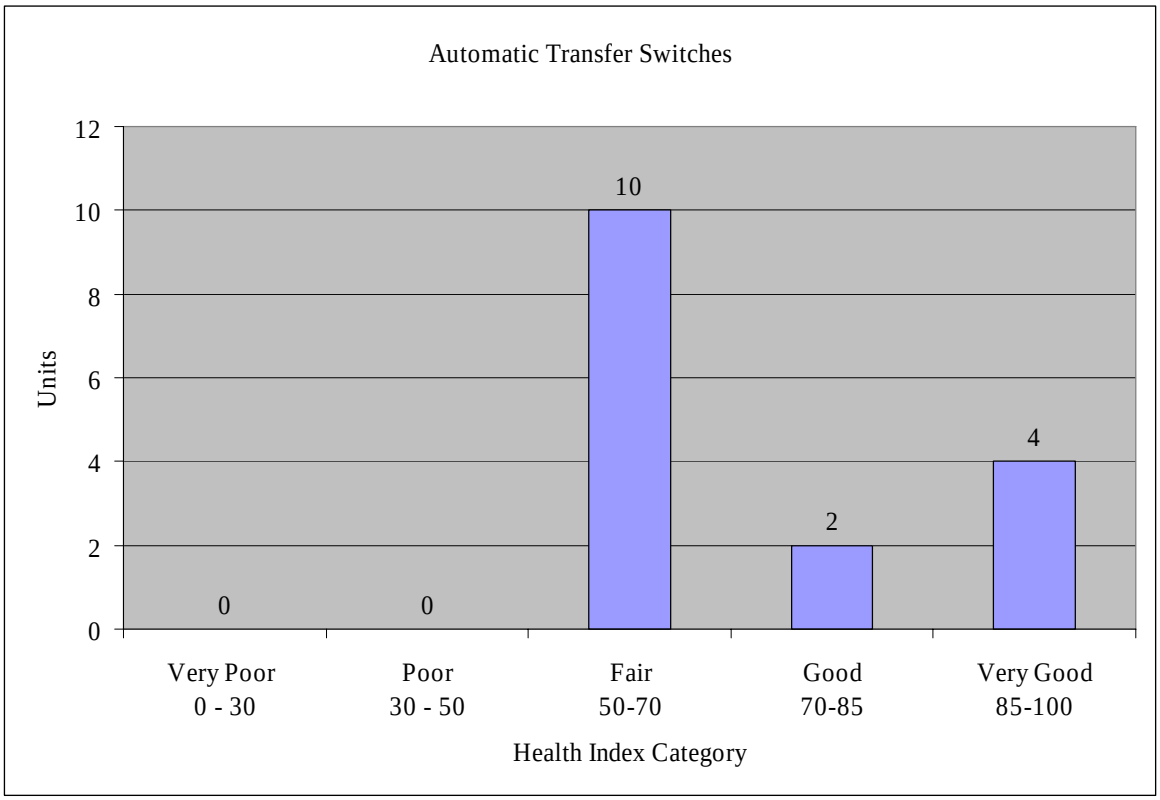
There was no age distribution data available for the automatic transfer switches.

Health indexes have been computed for the automatic transfer switches as described in Table 3-8 and Figure 3-18.

Table 3-8 Summary of Condition Rating Results for Automatic Transfer Switches

Condition Ratings: Automatic Transfer Switches						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Phase Barriers	87	0	0	0	0	87
Gasket	79	2	1	0	0	82
Overall/Other Condition	0	1	0	8	0	9
Years Since Overhaul	0	0	0	0	0	0
Age	0	5	4	0	0	9

Figure 3-18 Summary of Condition Assessment Results for Automatic Transfer Switches



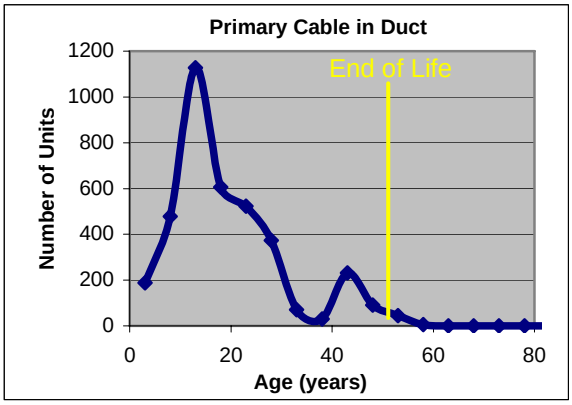
The Health Index indicates that none of the automatic transfer switches will need replacement in the next three years but that 62% will require replacement in the following seven years. This represents 71 switches when extrapolated to the entire population of 113 switches.

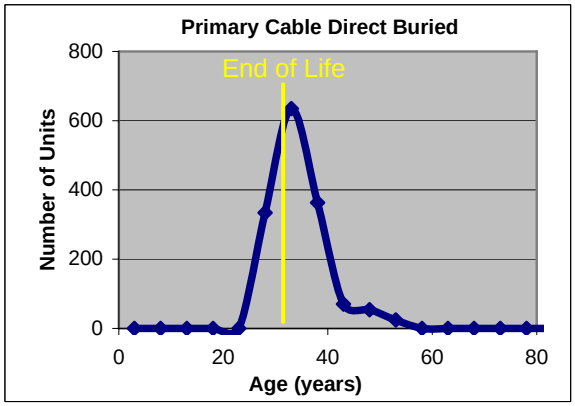
3.11 Underground Primary Cable

Distribution System Underground Cables consist of underground cables, splices/joints, elbows, potheads and terminators at voltage levels 27.6 kV, 25 kV, 13.8 kV and 4.16 kV. It includes direct buried and installed-in-duct feeder cables, underground cable sections running from stations to overhead lines and from overhead lines to customer service connections and switches.

The age distribution of the primary cable is shown in Figure 3-15, broken down into cable in duct and direct buried.

Figure 3-19 Age Distribution of Primary Cable





Health indexes have been computed for the primary cable as described in Tables 3-9 to 3-11 and Figures 3-16 to 3-18.

Table 3-9 Summary of Condition Rating Results for Direct Buried XLPE Underground Cables

Condition Ratings: Underground Cables						
	Number of Cables Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Age	4	0	4	14	49	71
Number of Failure in last 5 years	0	529	234	40	33	836

Note: the numbers in this table are the number of circuits.

Table 3-10 Summary of Condition Rating Results for Direct Buried XLPE Underground Cables

Health Index	Health Index Results Classification	Number of circuit km
70 - 100	Good	615
50 - 70	Fair	598
0 - 50	Poor	372
	Total	**1585**

Table 3-11 Summary of Condition Rating Results for PILC Cable in Duct

Health Index	Health Index Results Classification	Number of circuit km
70 - 100	Good	861
50 - 70	Fair	307
0 - 50	Poor	75
	Total	**1243**

The numbers in Tables 3-10 and 3-11 and Figures 3-20 to 3-22 are in circuit km because the cable failure data was most consistent on that basis.

Figure 3-20 Summary of Condition Assessment Results for All Underground Cables

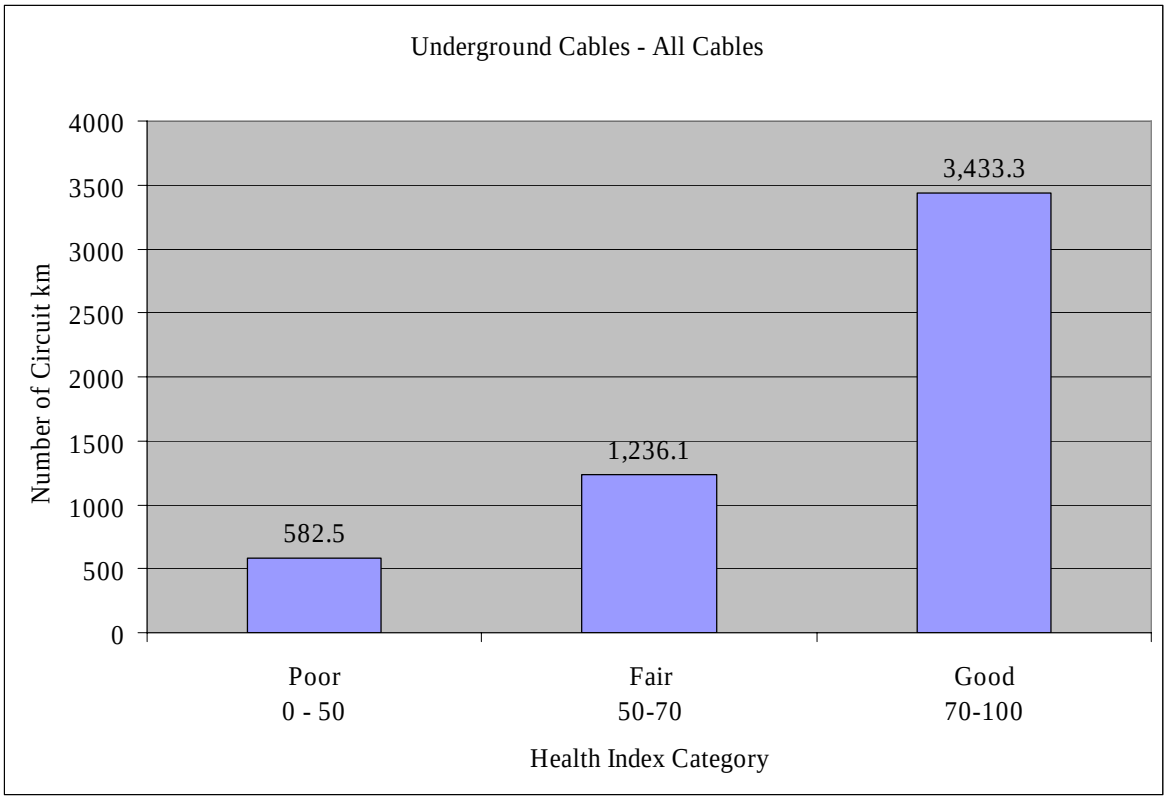


Figure 3-21 Summary of Condition Assessment Results for XLPE Direct Buried Underground Cables

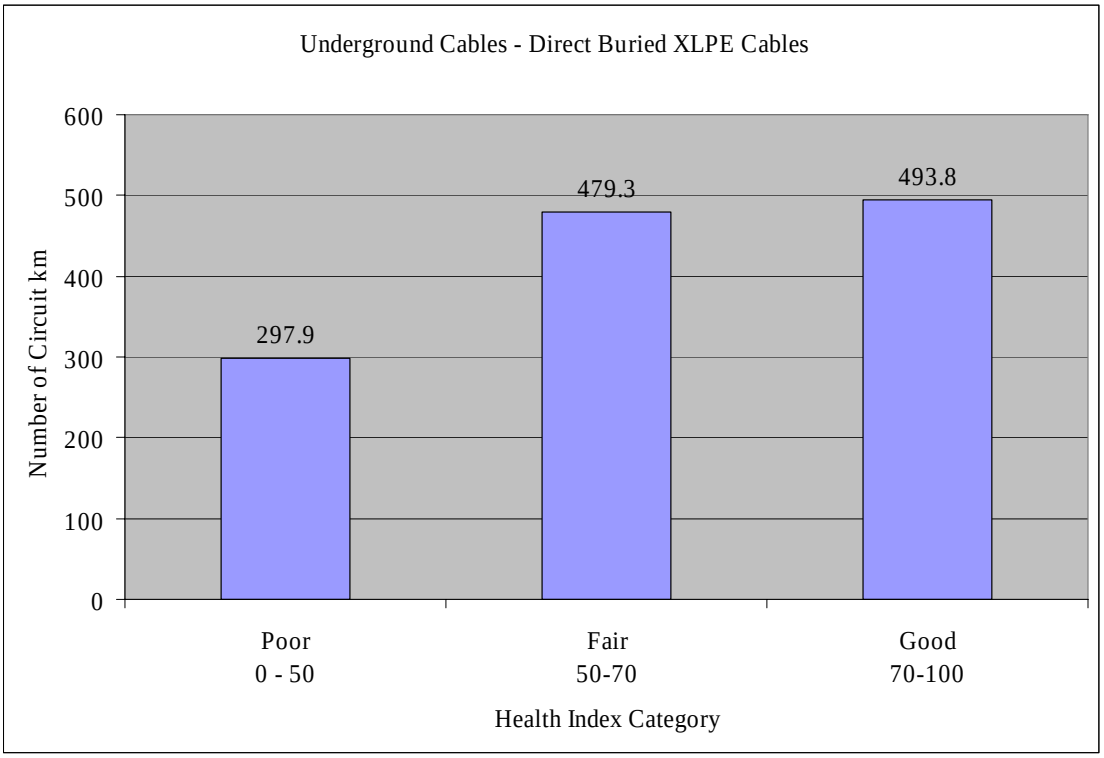
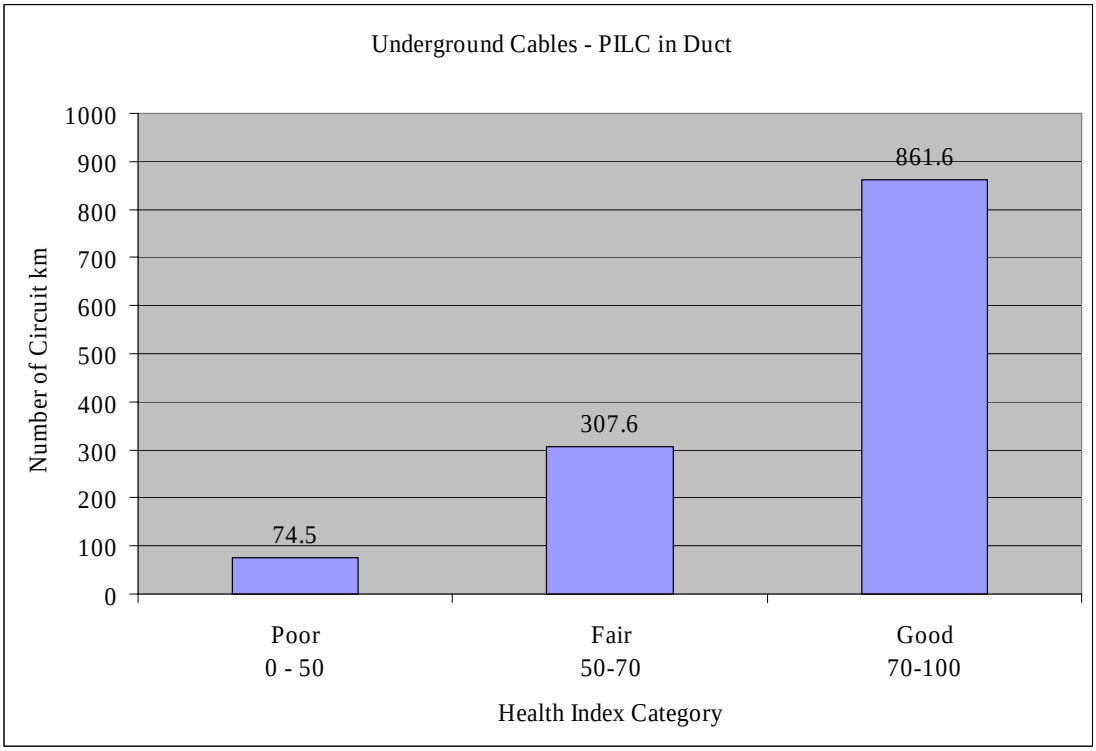


Figure 3-22 Summary of Condition Assessment Results for PILC Cables in Duct



The Health Index results indicate that 298 circuit km of XLPE direct buried cable should be replaced in the next three years, and 74 km of PILC in duct. In years 4 to 10, 479km of XLPE direct buried and 308 km of PILC in duct can be expected to require replacement.

In addition to the 1271 circuit km of direct buried XLPE and 1243 km of PILC in duct, there are also 2,497 circuit km of XLPE installed induct. This cable has had no failures so it is all classes in good condition.

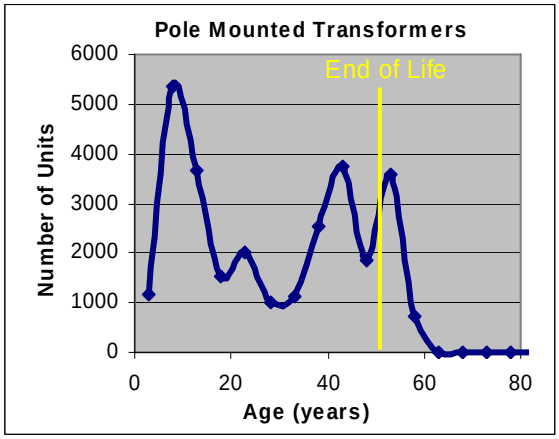
The conclusion that there are significant cable replacement requirements has been further substantiated through interviews with staff and analysis of customer outage data. The data shows that primary cable is the cause of 14% of the customer interruptions, over half of the total due to defective equipment. The customer outages caused by primary cable is steadily rising.

3.12 Pole Mounted Transformers

Pole mounted transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The cylindrical tank is mounted on a wood or concrete pole that supports the overhead conductors.

The age distribution for pole mounted transformers is shown in Figure 3-23.

Figure 3-23 Age Distribution of Pole Mounted Transformers



Although a Health Index for pole mounted transformers has been formulated, there was no existing data available for the input condition monitoring parameters. A Health Index cannot be computed until the data has been collected.

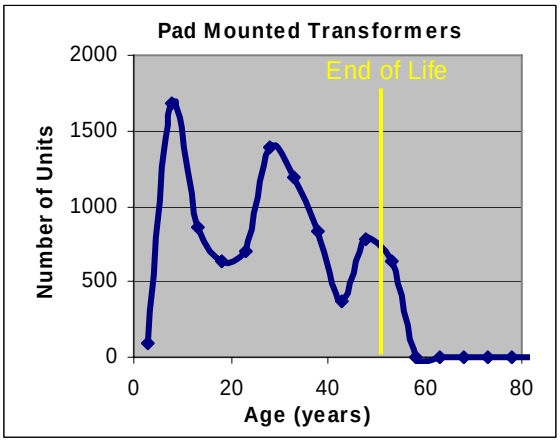
The age distribution in Figure 3-23 indicates that 35% of the total population, or 10,700 transformers will require replacement in the next ten years fairly evenly spread as 1,070 per year. This is a high rate of replacement, but it can be seen in Figure 3-23 that this is caused by an uneven distribution of ages in the population. The replacement rate in the following 10 years should be less.

3.13 Pad Mounted Transformers

Pad mounted transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The low profile tank is mounted on a concrete pad.

The age distribution for pad mounted transformers is shown in Figure 3-24.

Figure 3-24 Age Distribution of Pad Mounted Transformers

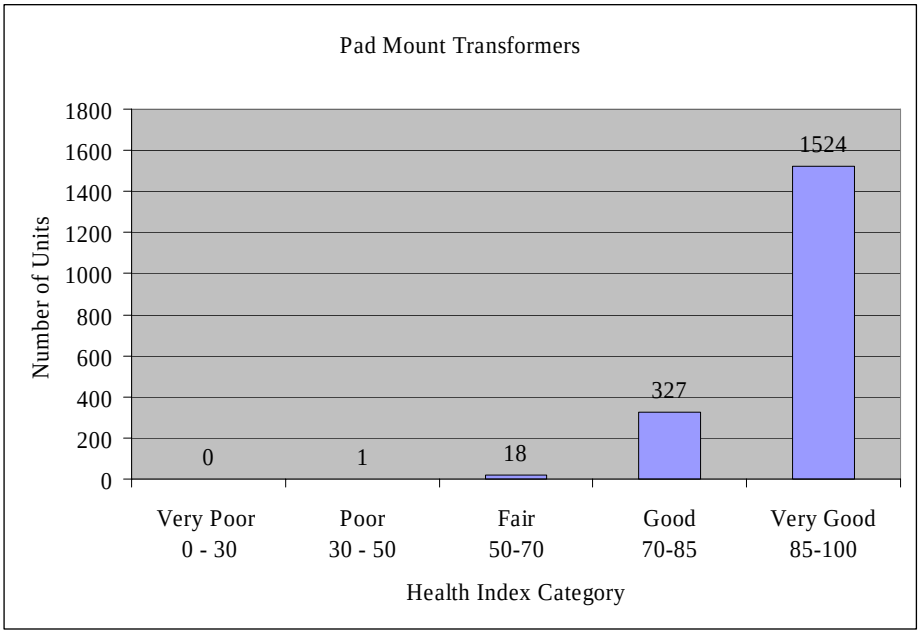


Health Indexes have been computed for the padmounted transformers as described in Table 3-12 and Figure 3-25.

Table 3-12 Summary of Condition Rating Results for Pad Mounted Transformers

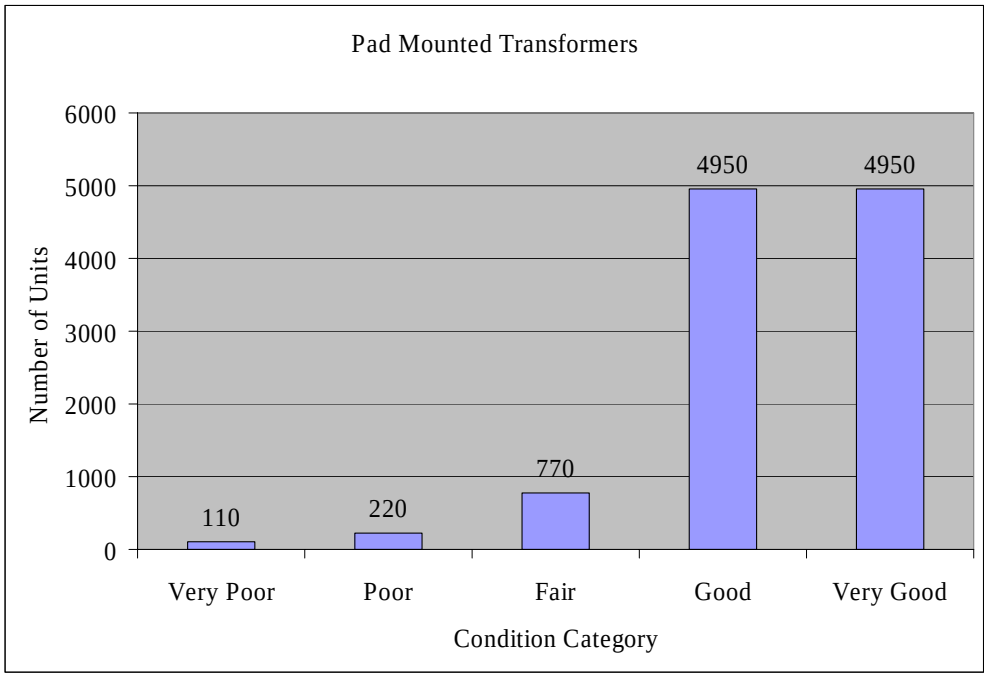
Condition Ratings: Pad Mounted Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	1838	49	0	2	0	1889
Oil Leaks	1163	54	0	14	0	1231
Corrosion/Paint	1457	399	7	99	0	1962
Transformer Lid Gaskets	1608	92	4	9	0	1713
Barriers	825	4	0	2	0	831
Grounding	1897	51	0	1	0	1949
Concrete Base	0	0	0	0	0	0
Secondary Connections	233	1716	0	2	0	1951
Latches/Handles/Locks/Door	1601	92	224	23	1	1941
Age	1773	482	505	128	7	2895

Figure 3-25 Summary of Health Index Results for Pad Mounted Transformers



The Health Index results indicate that no pad mounted transformers will require replacement in the next year, 0.05% in the following two years and 0.96% in years 4 to 10. This rate of replacement is lower than past experience would indicate to be a prudent planning level. The Health Index formulation is therefore under review. At the present time the best available estimate for remaining life of pad mounted transformers is based on age. This indicates that 1100 pad mounted transformers will need to be replaced in the next 10 years, or 20% of the total population. Figure 3-26 illustrates the condition assessment based on age.

Figure 3-26 Summary of Asset Condition for Pad Mounted Transformers

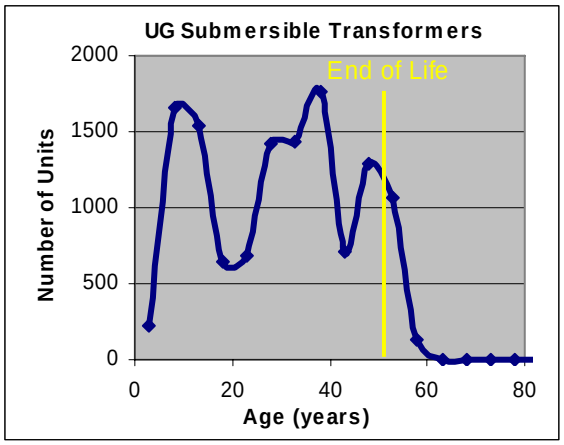


3.14 Submersible Transformers

Submersible transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The tank is installed in an underground concrete vault which has a steel, ventilated lid at ground level.

The age distribution for submersible transformers is shown in Figure 3-27.

Figure 3-27 Age Distribution of Submersible Transformers

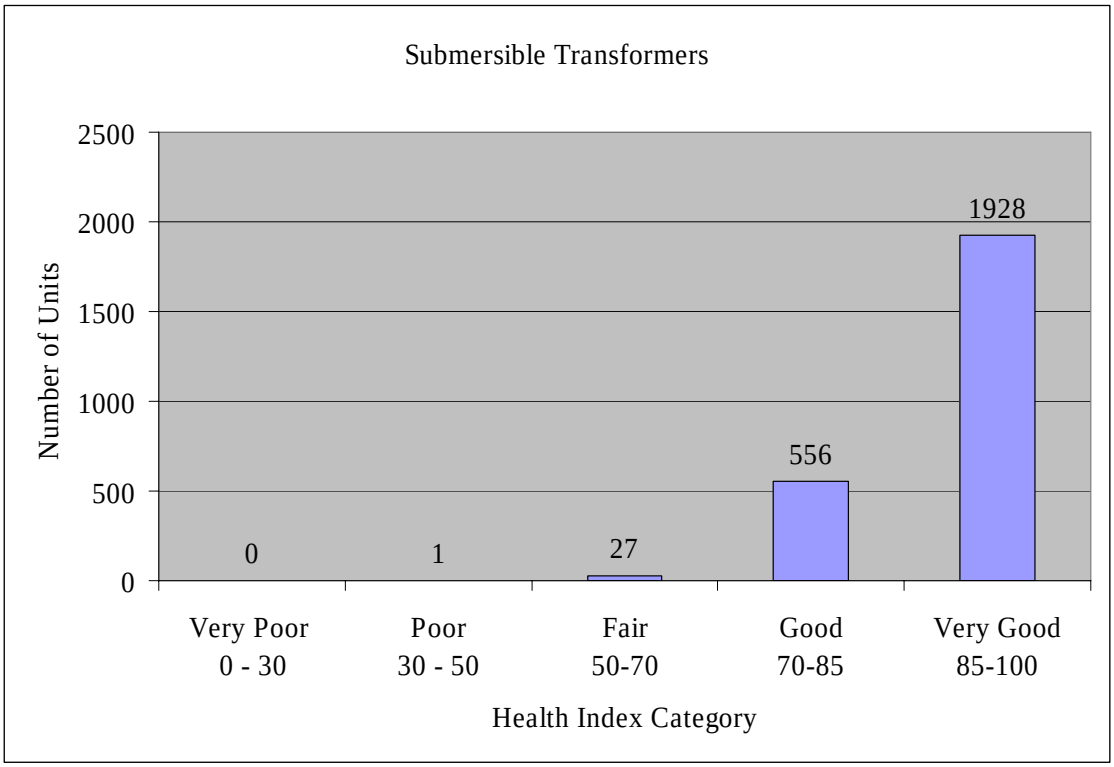


Health indexes have been computed for submersible transformers as described in Table 3-13 and Figure 3-28.

Table 3-13 Summary of Condition Rating Results for Submersible Transformers

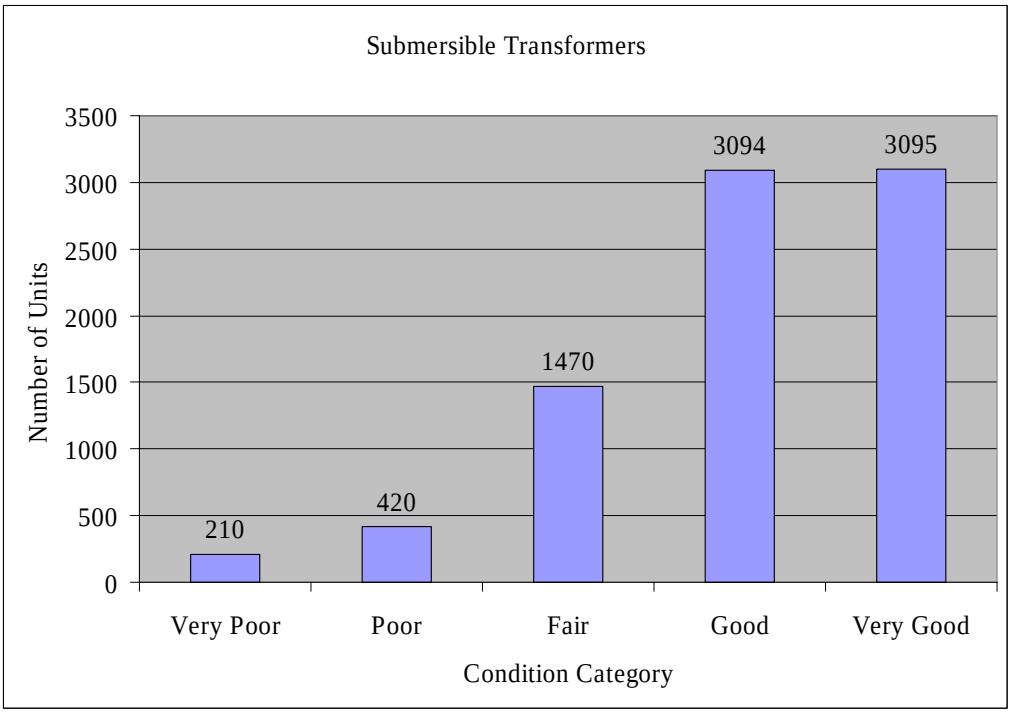
Condition Ratings: Submersible Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	2574	30	0	2	0	2606
Oil Leaks	1600	97	1	24	0	1722
Corrosion/Paint	1705	410	2	33	0	2150
Transformer Lid Gaskets	2234	248	69	15	1	2567
Barriers	0	0	0	0	0	0
Grounding	2605	20	0	0	0	2625
Secondary Connections/Primary Terminations	263	2350	0	9	0	2622
Age	2510	1981	1219	110	5	5825

Figure 3-28 Summary of Health Index Results for Submersible Transformers



The Health Index results indicate that no submersible transformers will require replacement in the next year, 0.04% in the following two years and 1% in years 4 to 10. This rate of replacement is lower than past experience would indicate to be a prudent planning level. The field audit found that the average condition was worse than that computed by the Health Index. The Health Index formulation is therefore under review. At the present time the best available estimate for remaining life of submersible transformers is based on age. This indicates that 2100 submersible transformers will need to be replaced in the next 10 years, or 25% of the total population. Figure 3-29 illustrates the condition assessment based on age.

Figure 3-29 Summary of Asset Condition Assessment for Submersible Transformers

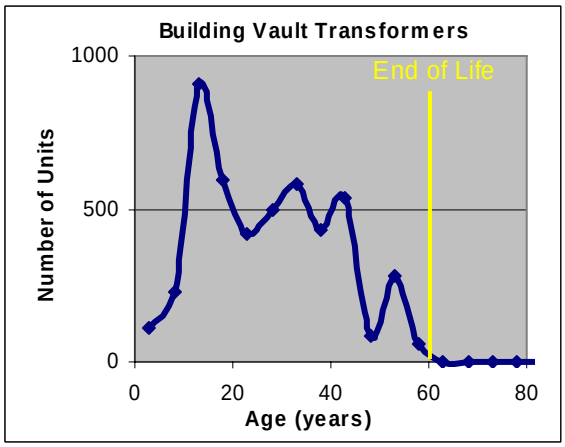


3.15 Vault Transformers

Building vault transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The tank is installed in a concrete room in a building.

The age distribution for vault transformers is shown in Figure 3-30.

Figure 3-30 Age Distribution of Vault Transformers

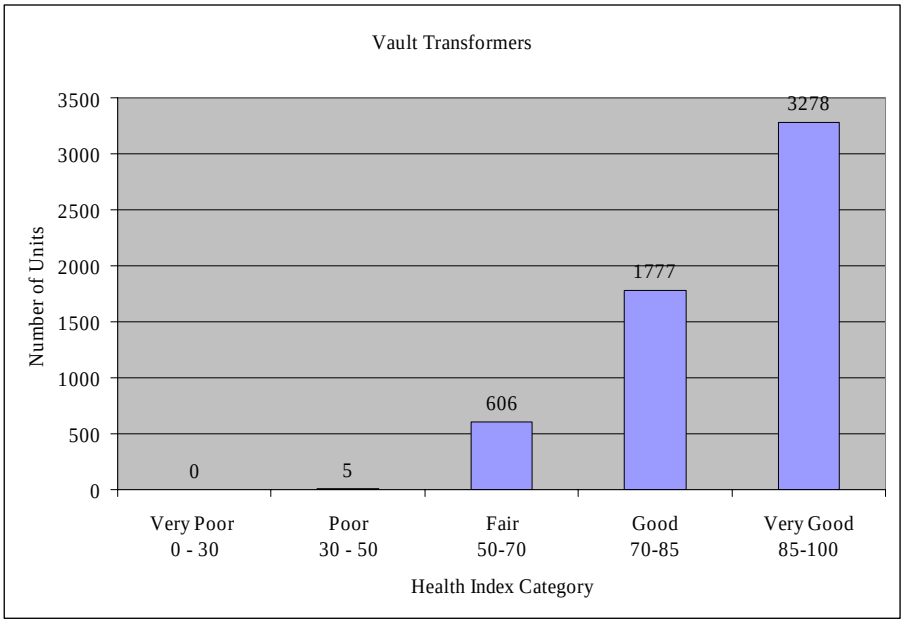


Health indexes have been computed for vault transformers as described in Table 3-14 and Figure 3-31.

Table 3-14 Summary of Condition Rating Results for Vault Transformers

Condition Ratings: Vault Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	4245	1745	0	12	0	6002
Oil Leaks	2974	939	3	11	1	3928
Corrosion/Paint	3097	1182	9	13	0	4301
Transformer Lid Gaskets	4103	1676	6	2	0	5787
Barriers	2657	1000	4	3	0	3664
Grounding	4322	1660	4	0	0	5986
Secondary Connections/Primary Terminations	4302	1680	0	9	1	5992
Age	2726	2048	2296	507	141	7718

Figure 3-31 Summary of Condition Assessment Results for Vault Transformers



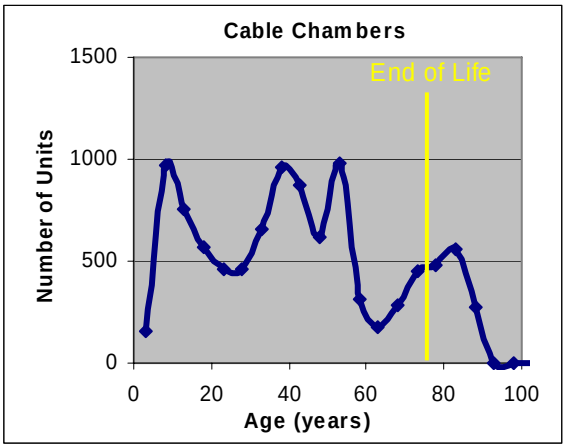
The Health Index results indicate that no vault transformers will require replacement in the next year, 0.09% in the following two years and 10% in years 4 to 10. This indicates that in the entire population of 12,409 units, 11 vault transformers will need to be replaced in years 2 and 3, and 1330 in years 4 to 10.

3.16 Cable Chambers

Cable Chambers or manholes facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance.

The age distribution for cable chambers is shown in Figure 3-32.

Figure 3-32 Age Distribution of Cable Chambers



Although a Health Index for cable chambers has been formulated, there was no existing data available for the input condition monitoring parameters. A Health Index cannot be computed until the data has been collected.

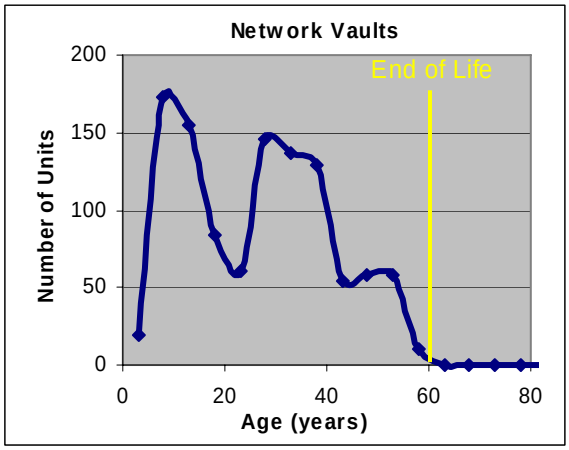
The age distribution in Figure 3-32 indicates that 35% of the total population will require replacement in the next ten years. However, cable chambers are expensive to replace and they can be maintained almost indefinitely, which often includes replacement of the roof or cover. This combination results in the lowest long term cost being achieved by repair rather than by replacement. Age is therefore not a good basis on which to estimate the number that need to be replaced. Past experience and engineering judgment have estimated the actual replacements to be 1% over the next ten years.

3.17 Network Vaults

Below ground equipment vaults are concrete structures that permit installation of transformers, switchgear or other equipment. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling.

The age distribution for network vaults is shown in Figure 3-33.

Figure 3-33 Age Distribution of Network Vaults



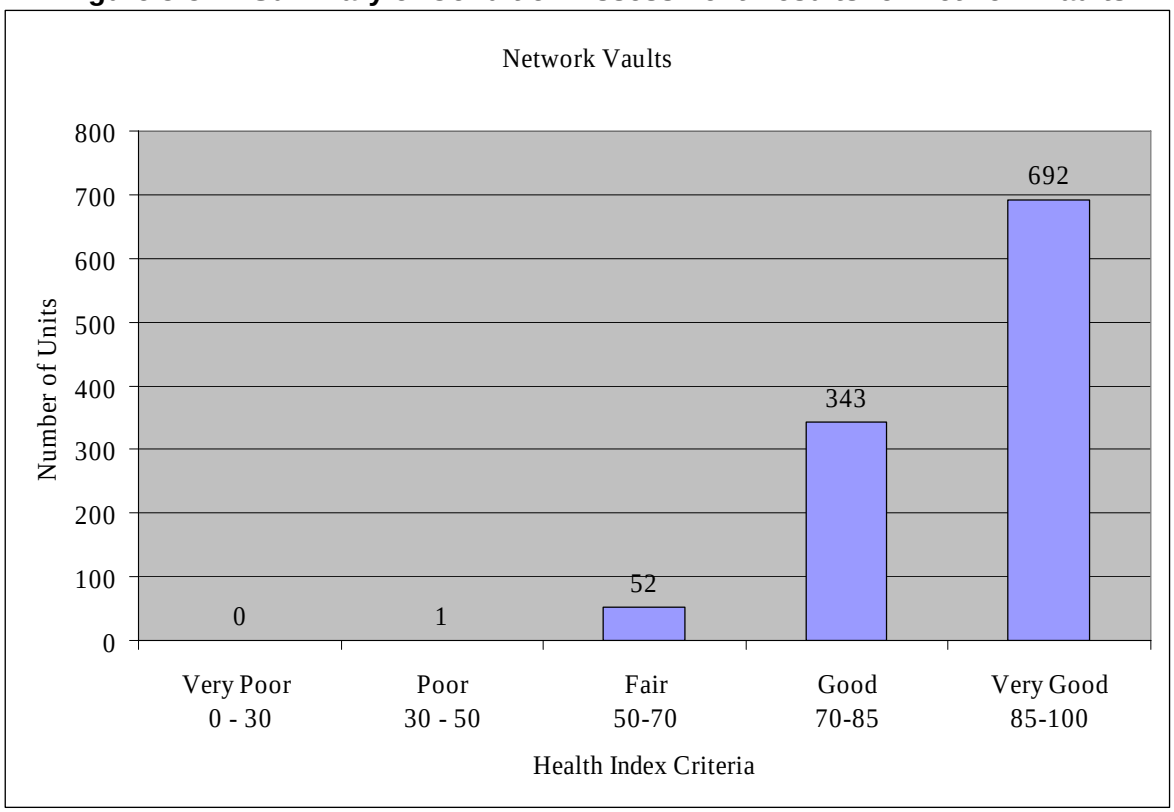
Health Indexes have been computed for network vaults as described in Table 3-15 and Figure 3-34

The Health Index results indicate that there are no network vaults that require replacement next year, 1 in years 2 to 3 and 52 in years 7 to 10. The field audit found vaults to be in slightly worse condition than the Health Index analysis. However, network vaults are quite maintainable and replacement is expensive. It may be possible to extend the life of these vaults by doing major maintenance such as roof replacement. This option could be a lower long term cost than replacement on the schedule indicated by the Health Index.

Table 3-15 Summary of Condition Rating Results for Network Vaults

Condition Ratings: Network Vaults						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Floor/Roof/Walls/Slabs	838	174	3	73	1	1089
Vents/Grills/Ventilation	1046	20	6	16	0	1088
Ducts/Cables	1015	29	0	42	1	1087
Locks/Hinges/Entry/Door/Ladder	863	27	211	74	1	1089
Flooding	649	32	34	46	0	761
Drain/Sump Pump	863	27	111	85	0	1086
Dirt Debris/Contamination	63	10	999	4	0	1076
Grounding	1069	7	1	8	0	1085
Fuses	696	21	0	6	0	723

Figure 3-34 Summary of Condition Assessment Results for Network Vaults



3.18 Summary of Asset Condition

Table 3-16 presents a summary of the information on asset condition.

Table 3-16 Summary of Asset Condition

Asset Group	Asset Condition					Total Population	EOL within 10 years
	Very Good	Good	Fair	Poor	Very Poor		Units (%)
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1732	87 (5%)
Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7490	2140	1070	30,709	10,700 (35%)
Submersible Transformers	3095	3094	1470	420	210	8,289	2,100 (25%)
Vault Transformers	7178	3900	1330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4950	4950	770	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6388	3194	159,700	31,940 (20%)
Overhead Switches – Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches – Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Cable – XLPE in Ducts	N/A	2497	0%	0%	N/A	2,497	0 km (0%)
Underground Cable – PILC in Ducts	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable – XLPE Direct Buried	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4985	4985	71	20	10	10,071	101 (1%)

4 FIELD AUDIT OF THESL ASSET CONDITION

4.1 Objectives

The field assessment of equipment condition was designed to provide a third party visual verification of the asset condition categories determined by Health Indexes. The audit was designed to be completed in a short time frame (a few weeks) identifying only the average condition of each asset class. A comparison can then be made to the results of the Health Index development process. Some differences between the two estimates of equipment condition can be expected since they are based on different sets of condition parameters.

4.2 Method

The major assets at THESL were divided into the 25 asset classes listed in Table 2-1.

For each asset class, locations for field inspection were identified. All of the TS locations where THESL owns equipment were inspected (18 of a total 35 stations). All other equipment was sampled at a statistically significant number of locations.

The equipment condition was assessed into four condition grades. Grade 1 was defined as basically new condition, grade 2 was normal wear, grade 3 was clear signs of age or degradation but still serviceable, and grade 4 was maintenance or replacement required. Grade 4 combines the Health Index condition categories 4 and 5.

The number of sampled locations was chosen so that the condition grade of the mean of the sample could be determined with 90% confidence, that is the 90% confidence interval on the mean would be less than 0.5. This means that if the audit was repeated with a different sample of locations then it would result in the same mean grade condition nine times out of ten. A larger sample size would not result in a better estimate of condition since the mean would still be in the same condition grade. The detailed calculation of the statistically significant sample size is included in Appendix C. Basically the number of samples required increases when the standard deviation of the sampled data increases. In the worst case, with samples evenly distributed over the four condition grades, this results in a requirement for 25 samples, in order to have the 90% confidence interval less than 0.5. In some asset types the maximum required number of samples were inspected, but in others the standard deviation of the data was determined from the first 15 samples and found to be low enough that 15 samples were sufficient.

The field assessment was based on a visual inspection. The actual locations for inspection were chosen so that they were geographically distributed over the entire operating area in proportion to the size of the population in the local area. Wherever possible they were selected to cover the entire age range of the population in proportion to the population in each age range. Beyond these two conditions, locations were selected at random.

4.3 Results of the Field Audit

The following Figures show the results of the field audit for each of the 25 classes of equipment. Each figure shows the number of samples inspected and the distribution of condition grades

obtained, including the mean and the 90% confidence interval on the mean. These results will be directly compared with the Health Indexes determined from asset condition data in Section 8 of this report.

Figure 4-1 Power Transformer Field Audit

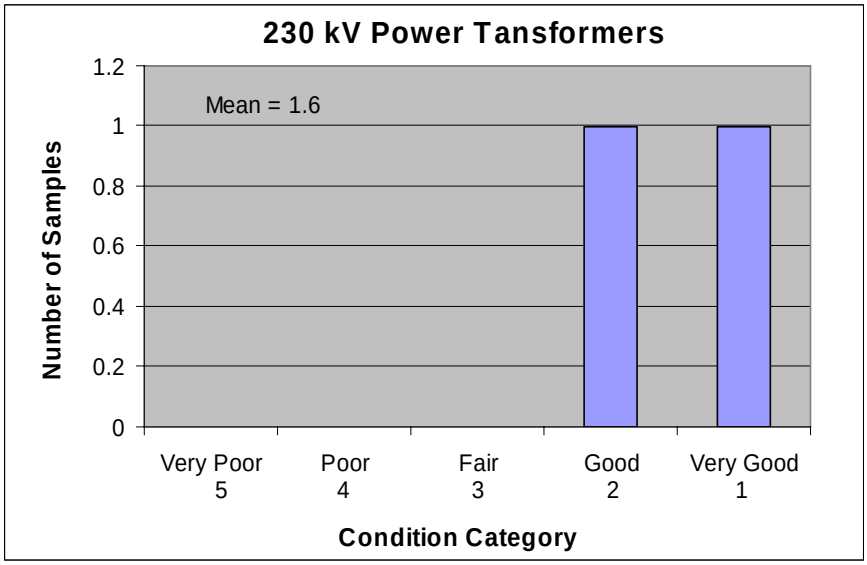


Figure 4-2 27.6 kV Breakers Field Audit

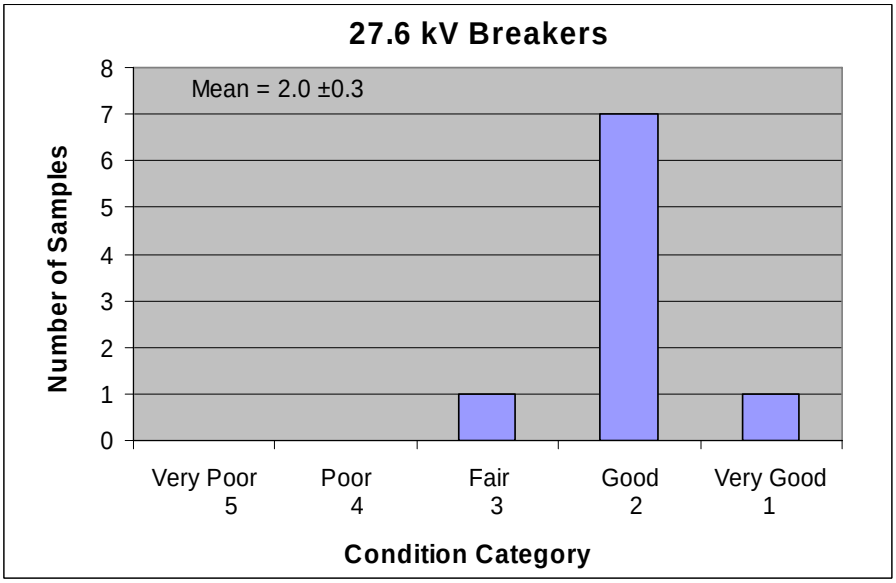


Figure 4-3 13.8 kV Breakers Field Audit

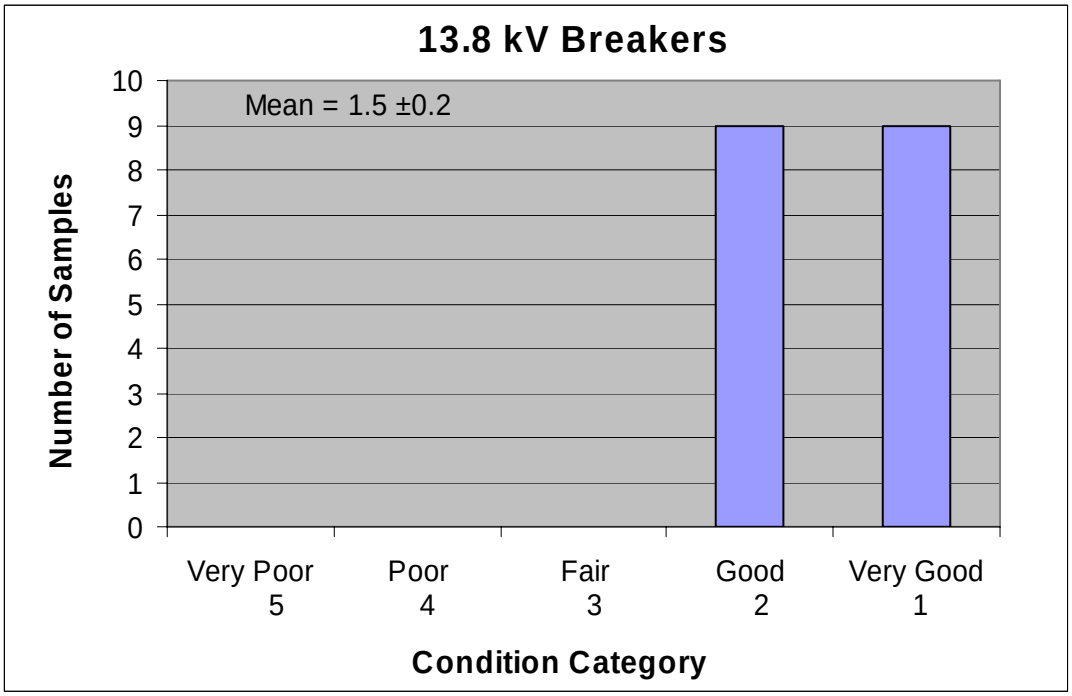


Figure 4-4 27.6 kV Switchgear Field Audit

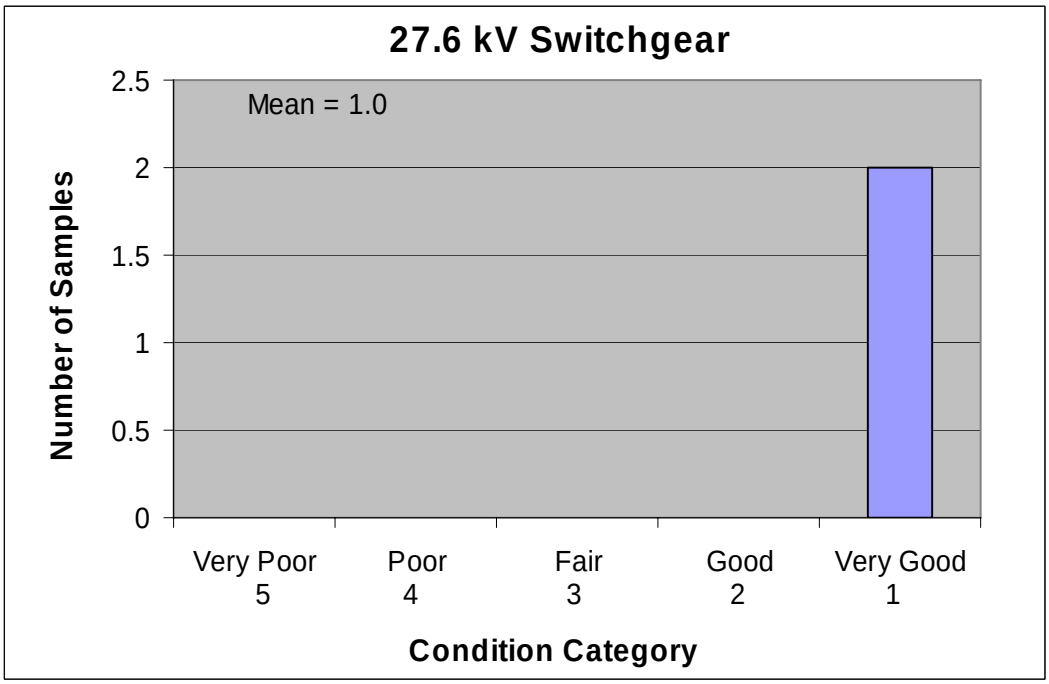


Figure 4-5 13.8 kV Switchgear Field Audit

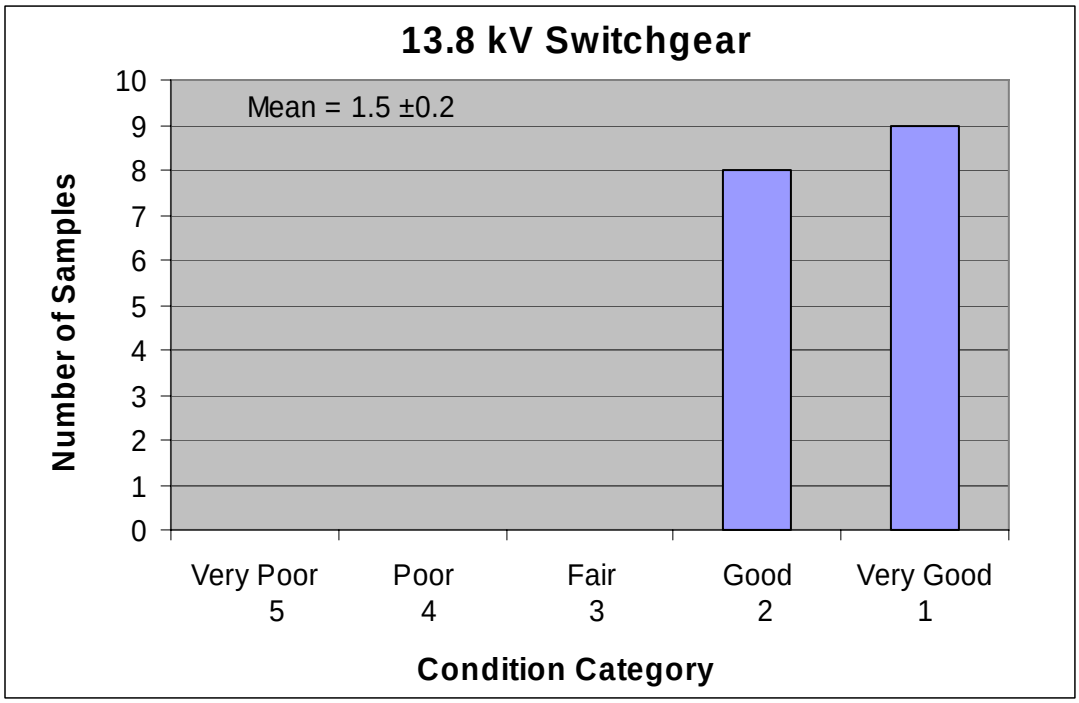


Figure 4-6 Example 13.8 kV Switchgear

Figure 4-7 Buildings Field Audit

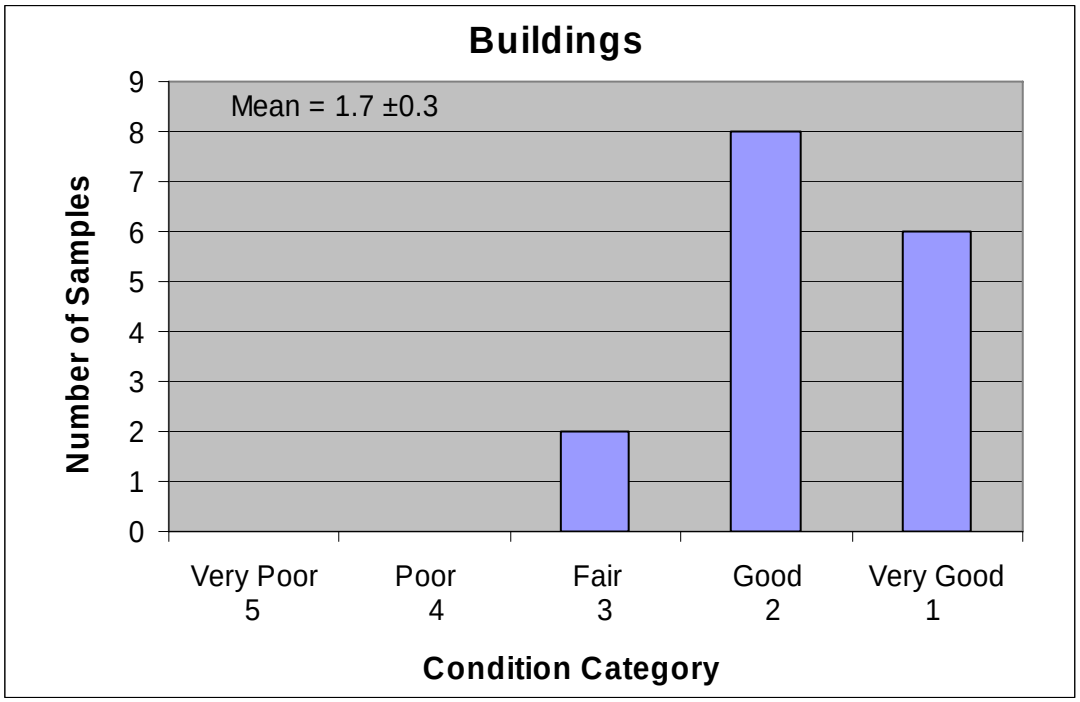


Figure 4-8 Example Building

Figure 4-9 27.6kV - 13.8kV Power transformer Field Audit

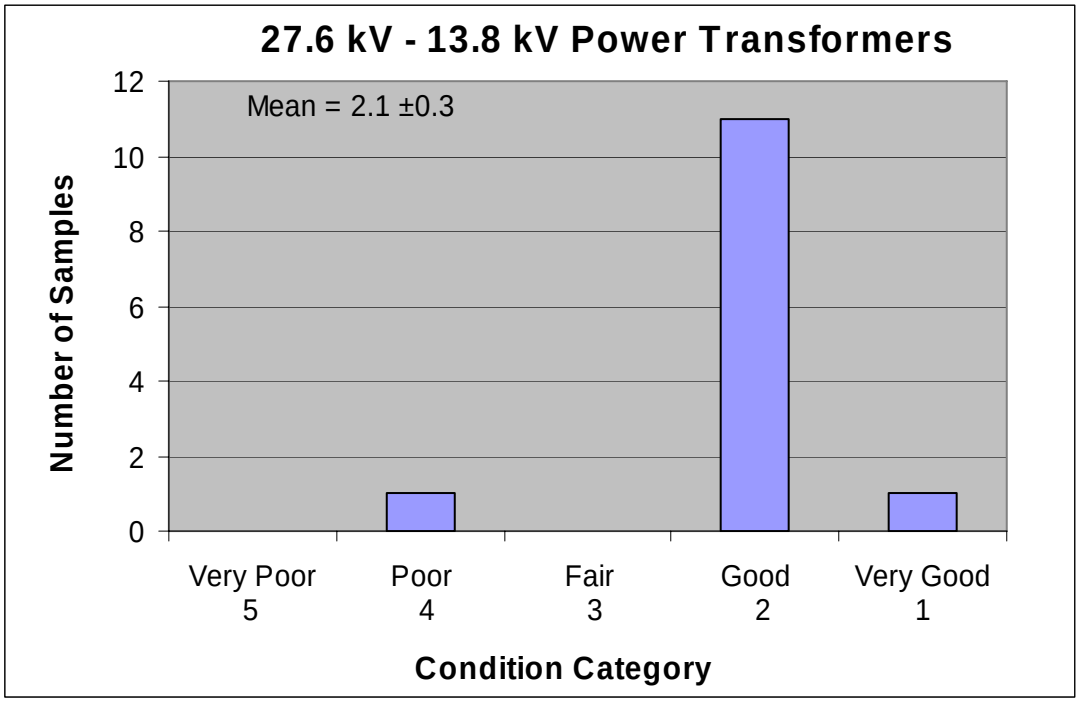


Figure 4-10 Example 27.6kV -13.8kV Power Transformer

Figure 4-11 27.6kV-4.16kV Power Transformer Field Audit

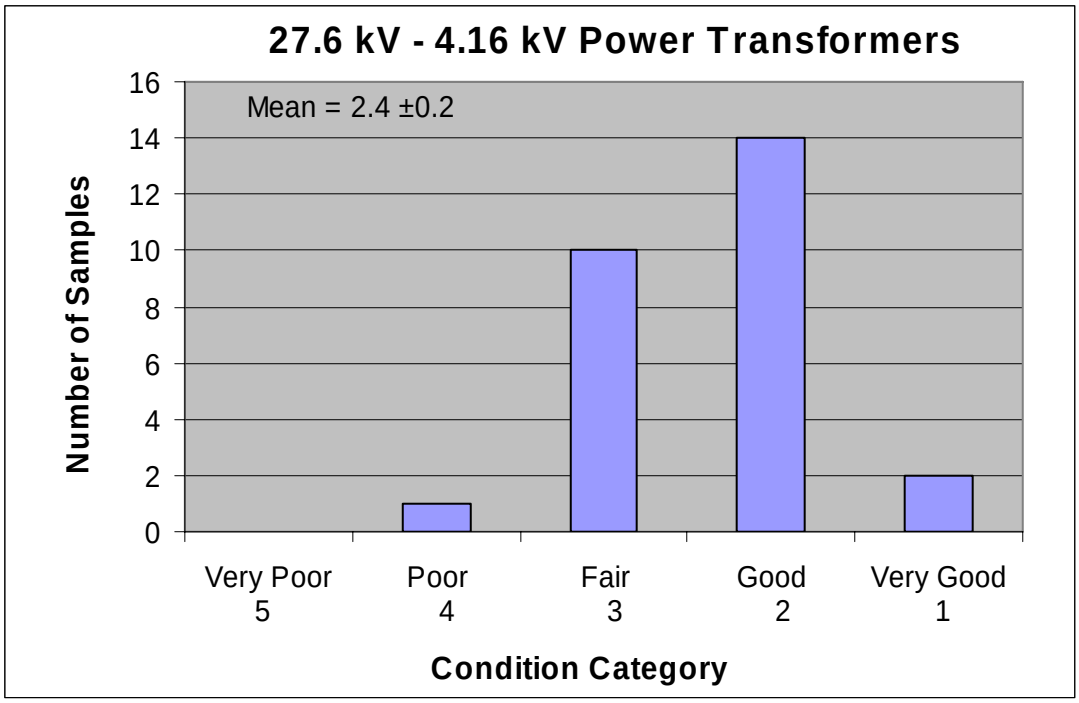


Figure 4-12 13.8kV-4.16kV Power Transformer Field Audit

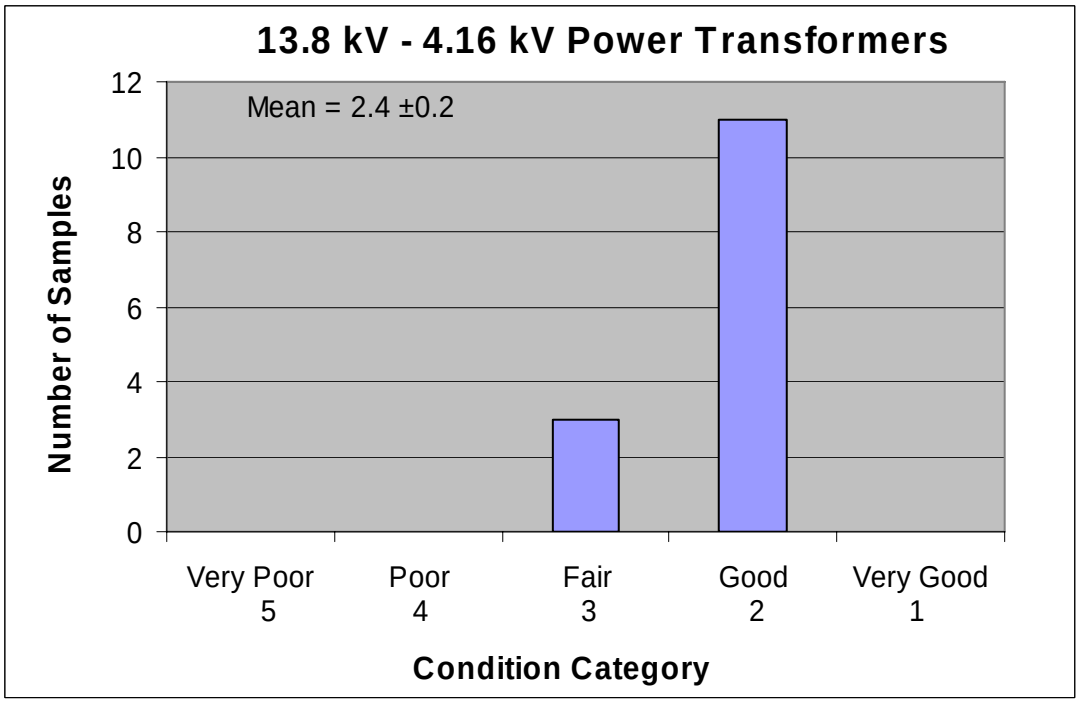


Figure 4-13 13.8 kV DS Switchgear Field Audit

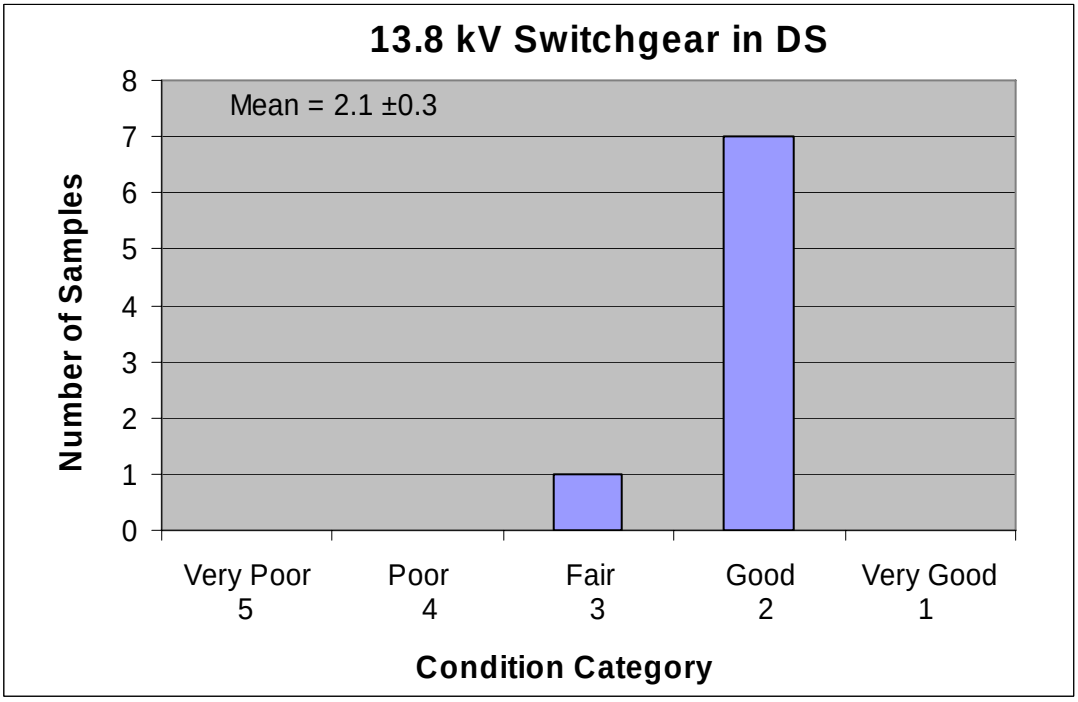


Figure 4-14 4.16 kV Switchgear Field Audit

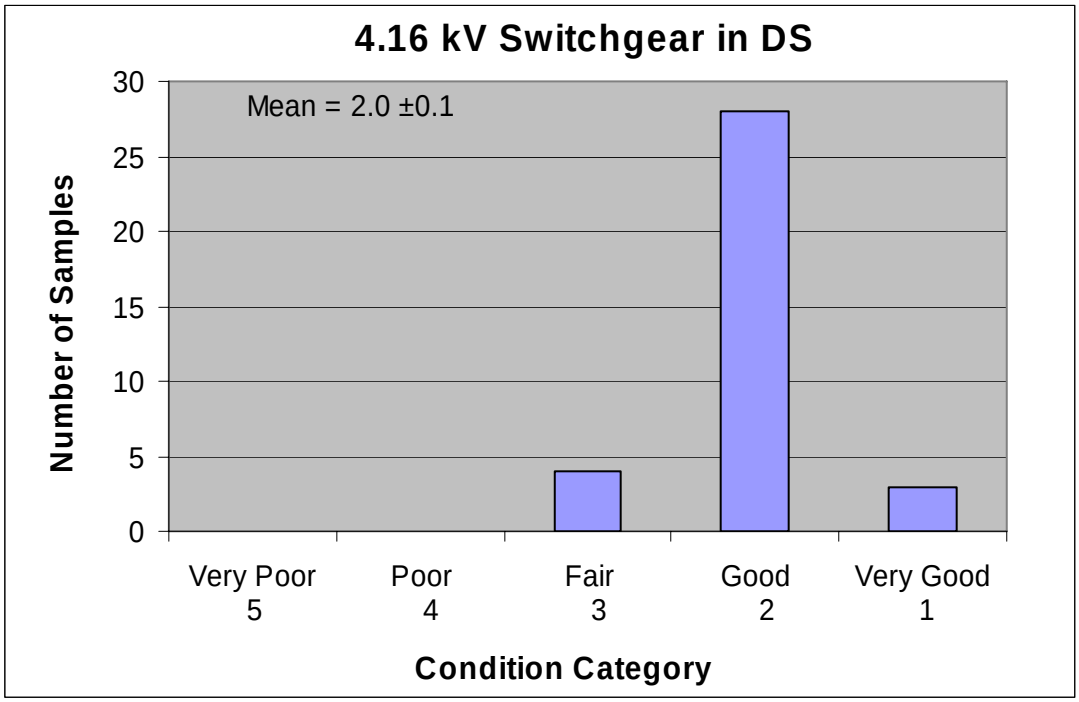


Figure 4-15 Transformer/Protector Units Field Audit

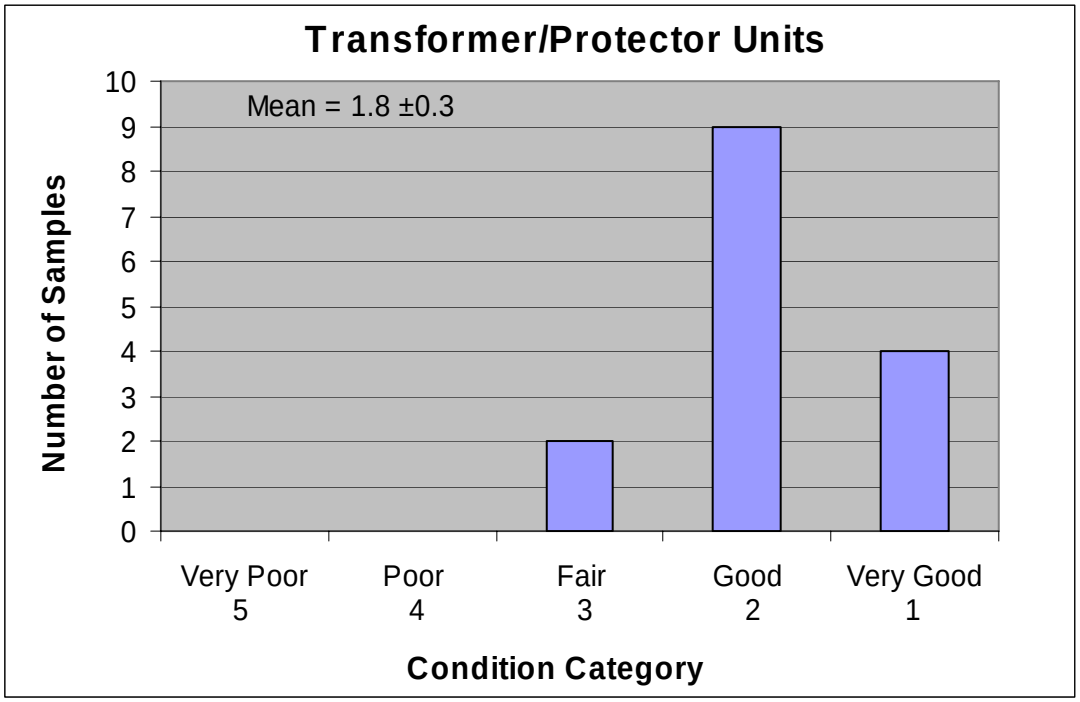


Figure 4-16 Example Transformer/Protector Units

Figure 4-17 Wood Pole Field Audit

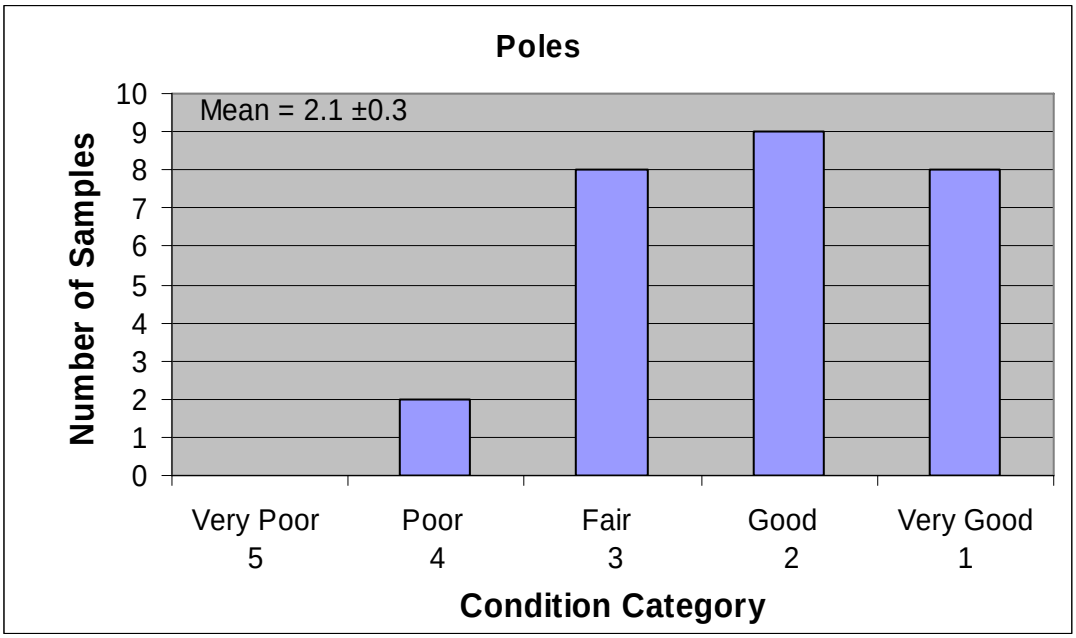


Figure 4-18 Example Wood Poles

Figure 4-19 Remotely Operated Overhead Switch Field Audit

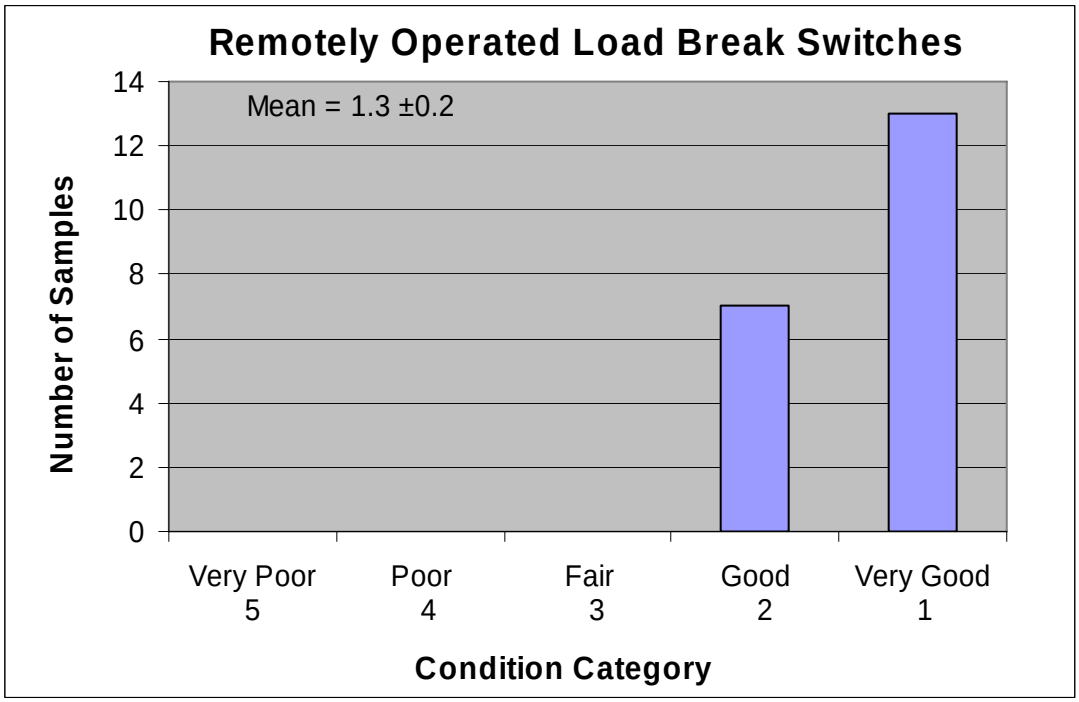


Figure 4-20 Example Remotely Operated Overhead Switch

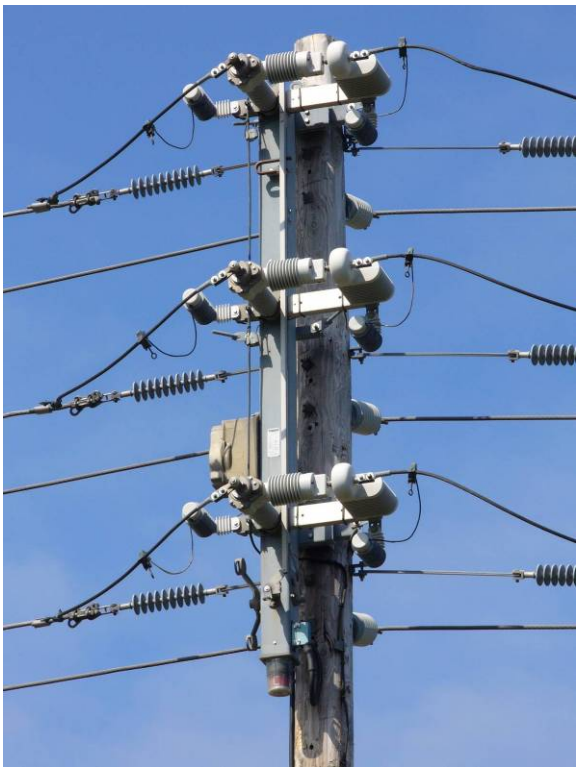


Figure 4-21 Manual Overhead Switch Field Audit

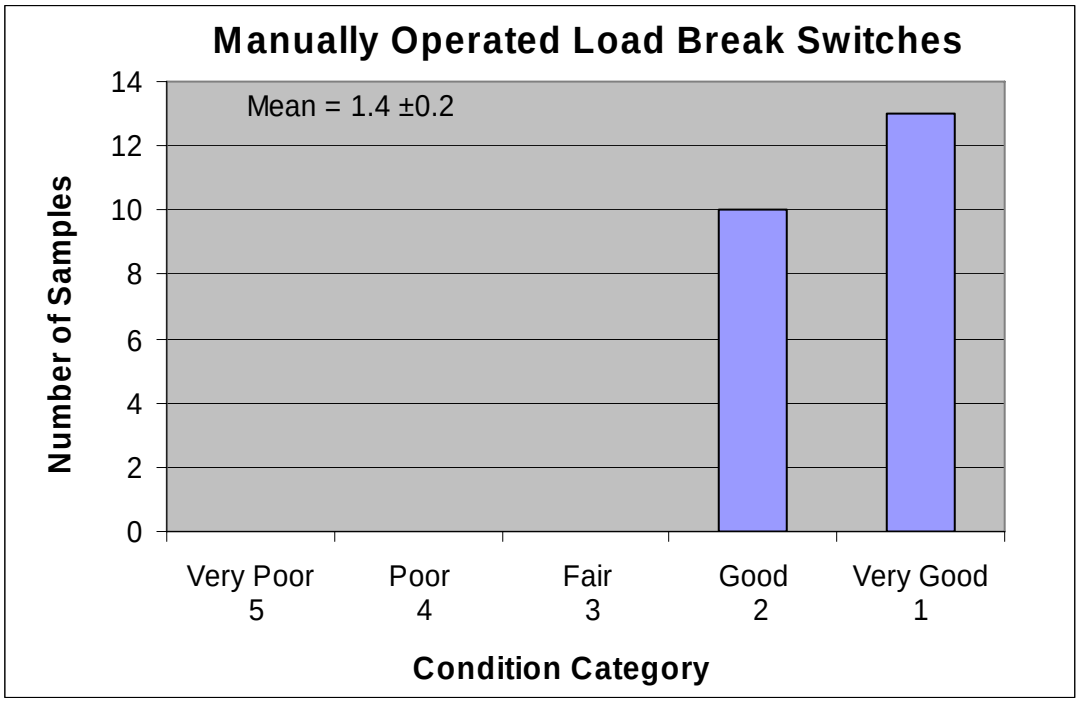


Figure 4-22 Example Manual Overhead Switch

Figure 4-23 Pad Mounted Switch Field Audit

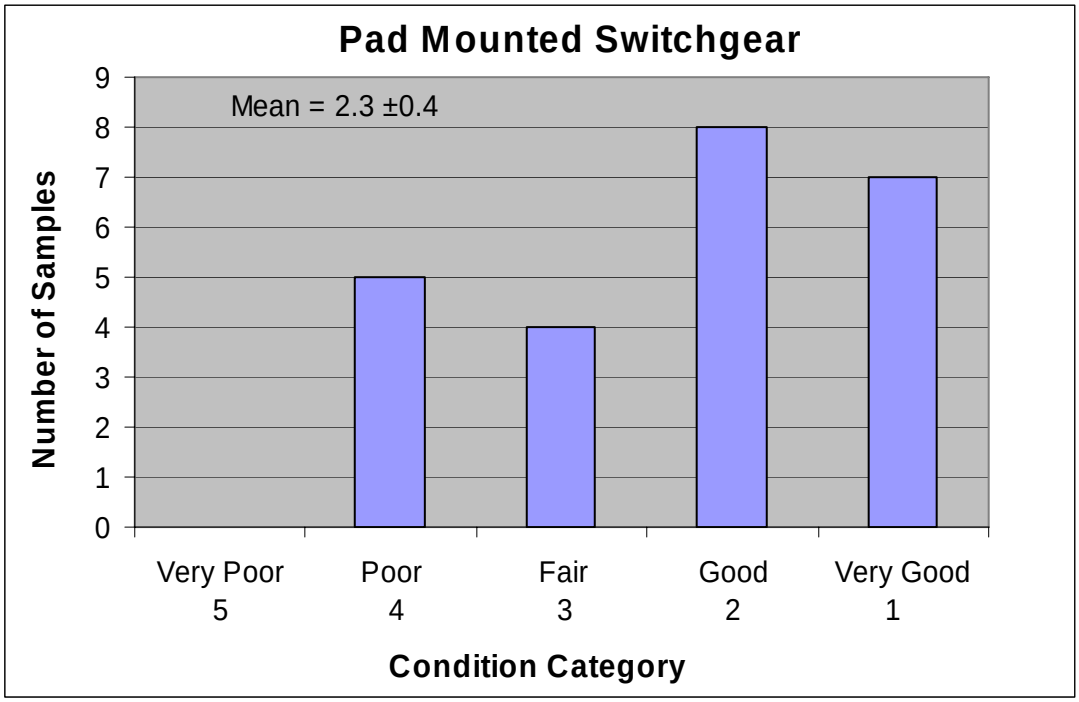


Figure 4-24 Example Pad Mounted Switch

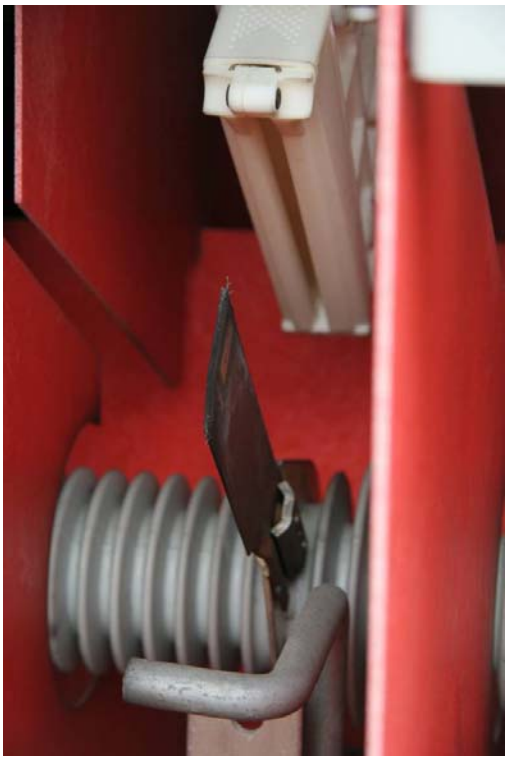


Figure 4-25 Auto Transfer Switch Field Audit

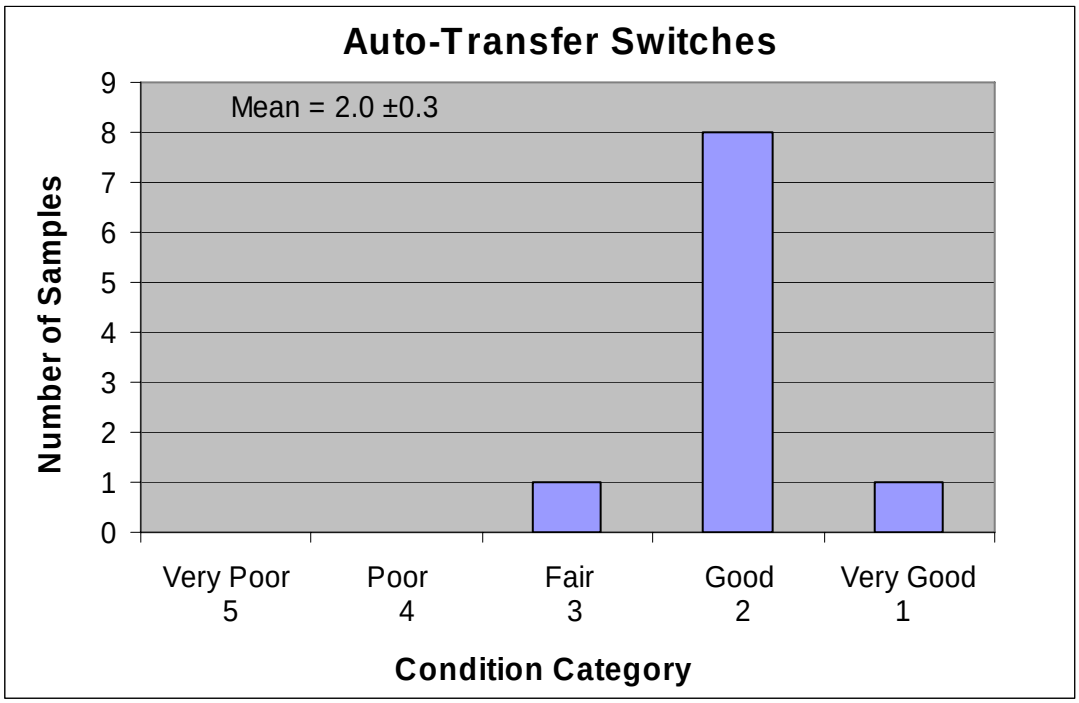


Figure 4-26 Example Auto Transfer Switch

Figure 4-27 Primary Cable Field Audit

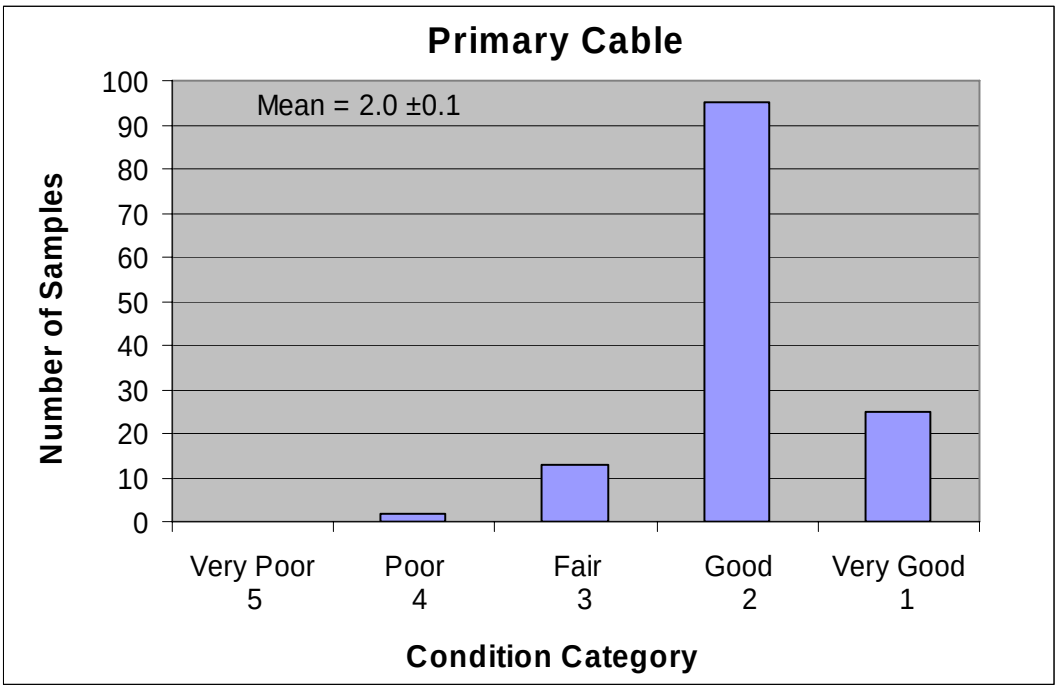


Figure 4-28 Example Primary Cable

Figure 4-29 Pole Mounted Transformer Field Audit

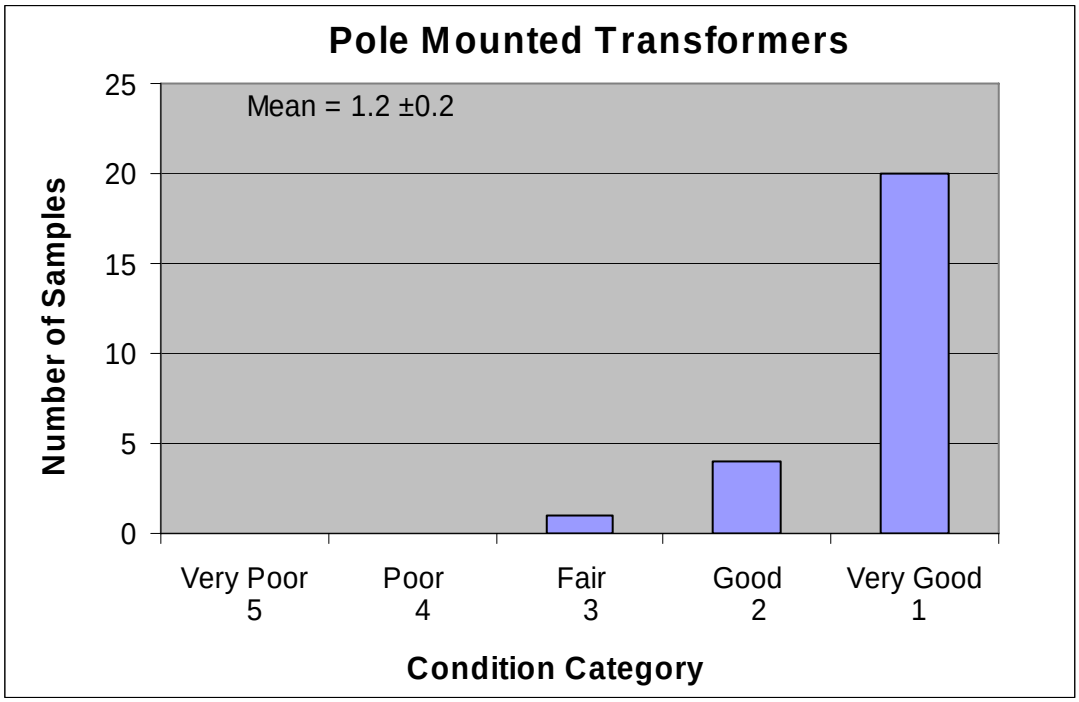


Figure 4-30 Example Pole Mounted Transformers

Figure 4-31 Pad Mounted Transformers Field Audit

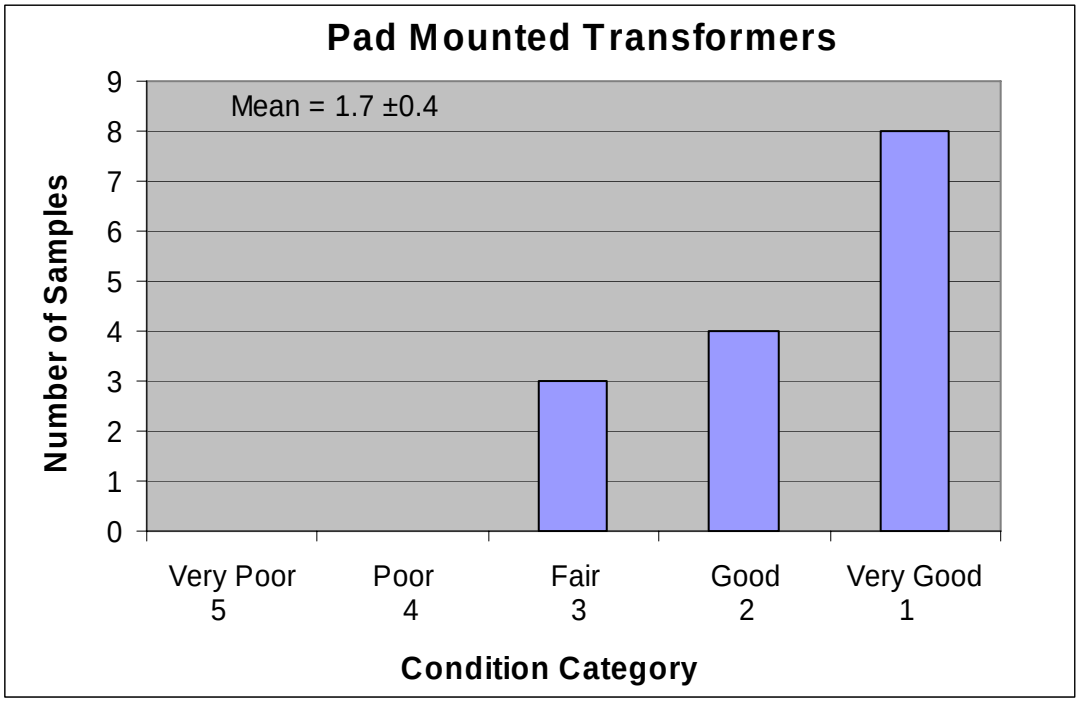


Figure 4-32 Example Pad Mounted Transformers

Figure 4-33 UG Submersible Transformer Field Audit

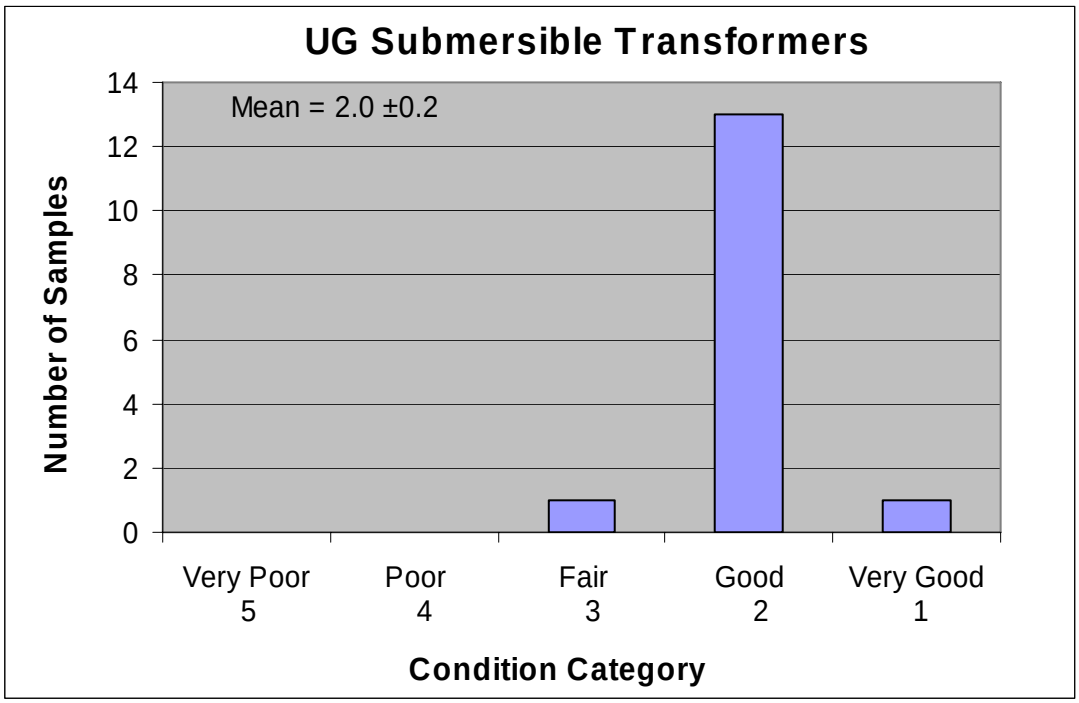


Figure 4-34 Example UG Submersible Transformer

Figure 4-35 Building Vault Transformer Field Audit

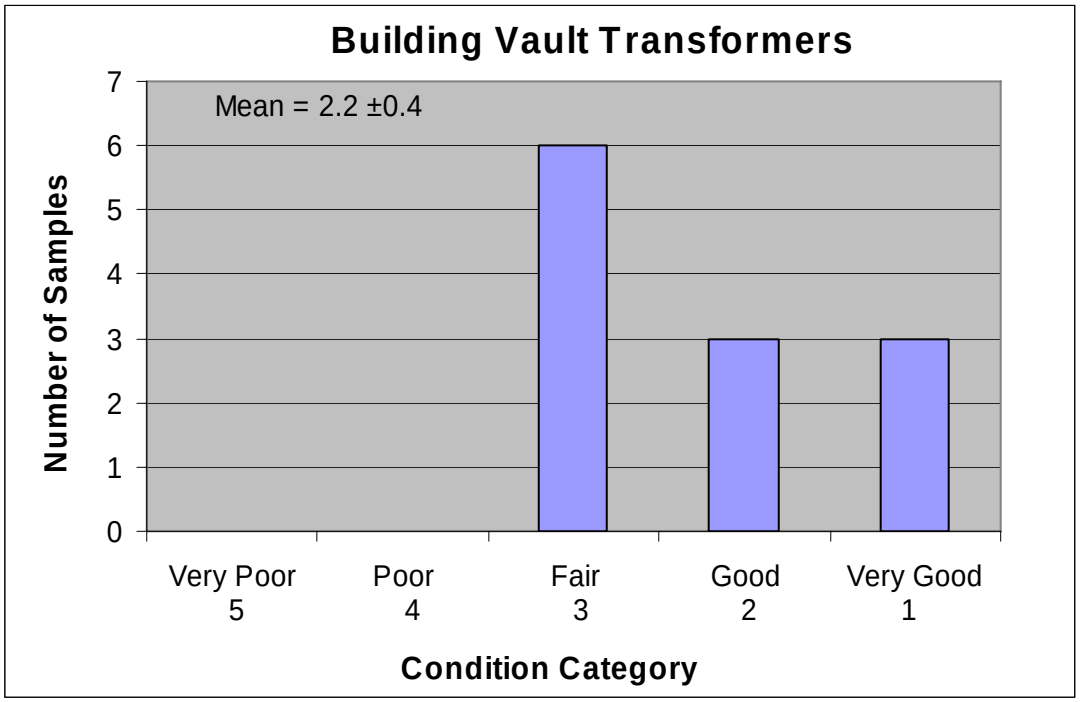


Figure 4-36 Example Building Vault Transformer

Figure 4-37 Cable Chamber Field Audit

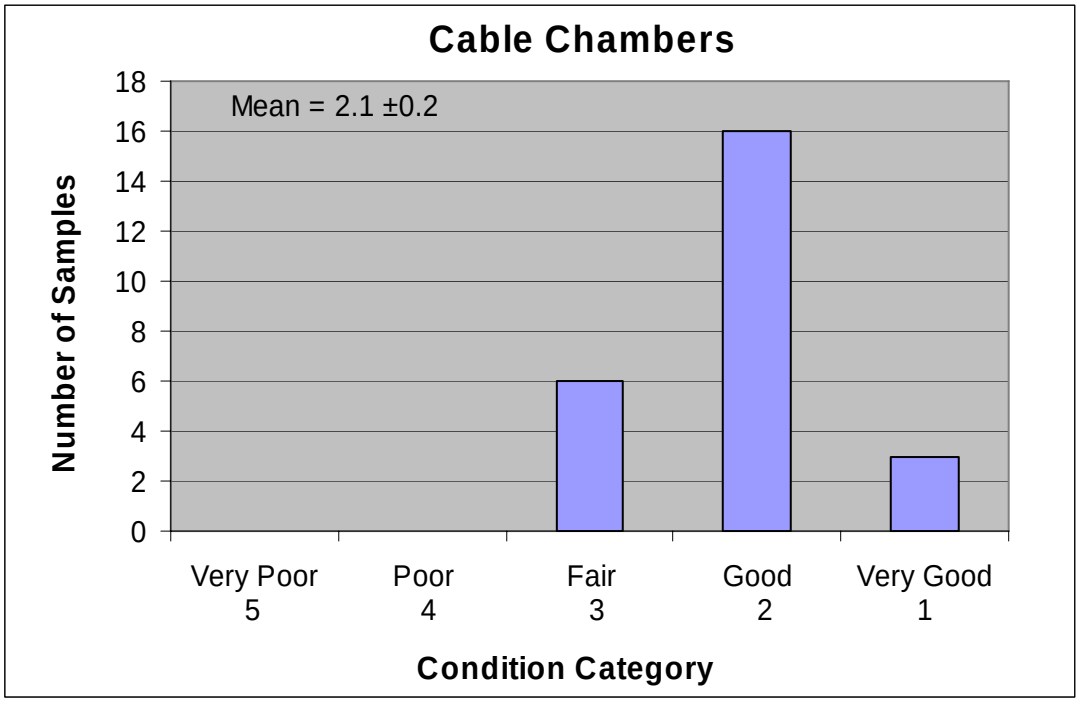


Figure 4-38 Example Cable Chambers

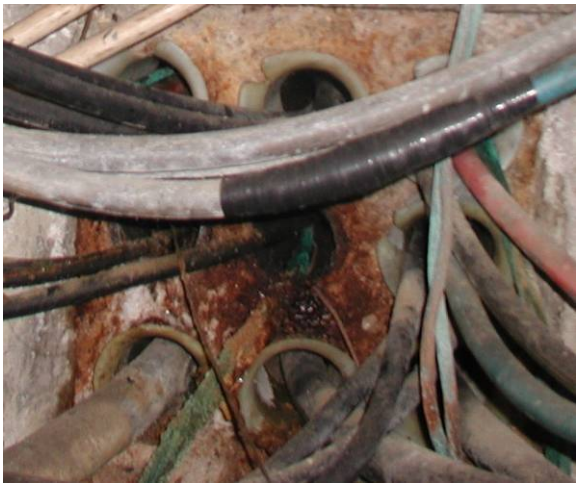


Figure 4-39 Network Vaults Field Audit

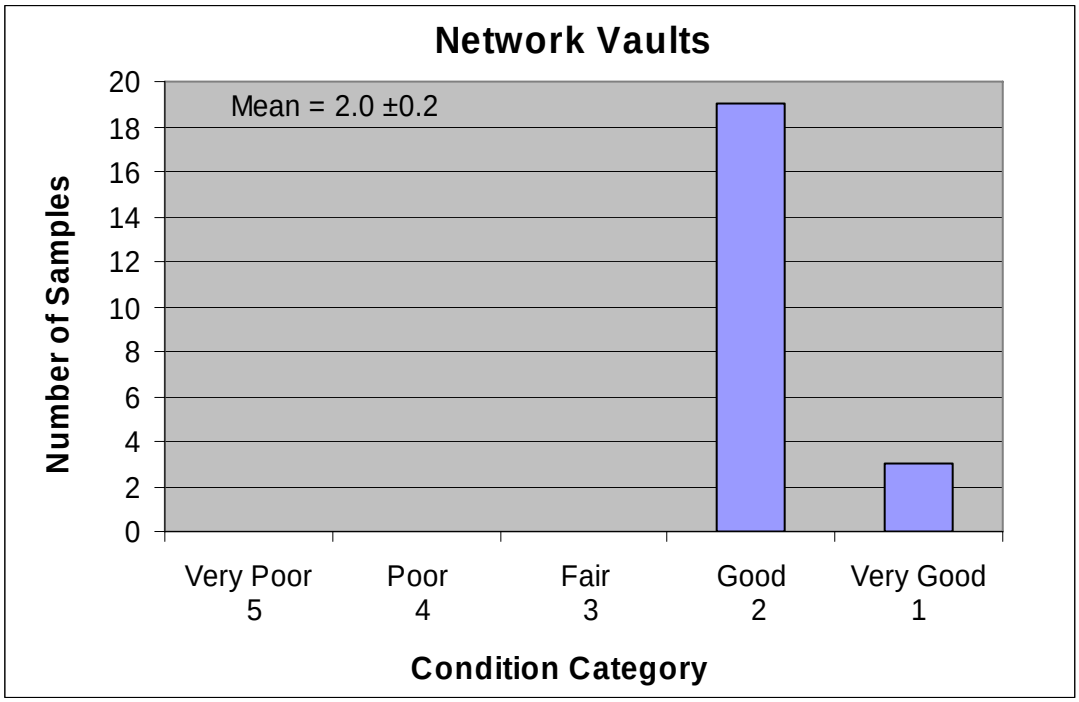


Figure 4-40 Example Network Vault

4.4 Interpretation and Significance of the Field Audit Results

The field audit results show that the major classes of THESL equipment are on average in good condition. This indicates that the past maintenance programs at THESL have been adequate. The equipment on average should reach its normally expected end of life.
Figure 4-41 below shows an example of old circuit breakers that have recently been rebuilt and can be expected to provide good service for many years to come.

Figure 4-41 Example of Old Equipment in Good Condition

The field audit found individual samples of equipment that are in need of replacement or repair. If no equipment were found to be in poor condition it would indicate that the equipment is being over maintained or replaced before its end of life. The field audit results indicate that this is not the case at THESL. Figure 4-42 shows examples of oil leaks from equipment. Repairing these leaks is part of normal maintenance. The leaks do not indicate that the equipment is at the end of its useful life.

Figure 4-42 Examples of Oil Leaks

For power transformers load history and oil analysis are much better indicators of condition. For breakers contact resistance and opening time are better indicators. For underground primary cables, failure rate is a much better indicator. The audit can only detect gross discrepancies between the Health Index based on THESL existing condition assessment techniques and the condition of equipment in the field.

4.5 Comparison of Field Audit with Health Index Condition

Since the audit determined the average condition category of each asset class, the audit results can be compared with the average condition category as determined by the Health Indexes. This comparison is shown in Table 8-1 below and on the bar chart (Figure 8-1) on the next page. A low number on the condition category indicates better condition (1 is “very good”, 5 is “very poor”).

The difference between the two estimates of asset condition category is not always large enough to be larger then the uncertainty in the estimates, i.e. large enough to be a significant difference. The audit results are statistically accurate to ±0.3, but the underlying accuracy of the assessment technique, which was an external visual inspection, makes the practical accuracy range at least ±0.5. The accuracy of the Health Index based condition category cannot be precisely calculated but it should be better than the audit. A value of ±0.2 is reasonable. The difference can therefore be considered significant if it is larger than ±0.7.

The Health Index for the following assets was not included in the comparison because of problems in the underlying data, as discussed in section 5.3: wood poles, circuit breakers, buildings, switchgear assemblies, and pole mounted transformers.

The third column in Table 8-1 shows that the two estimates of asset condition are in agreement for most asset classes.

For the first three asset classes, with a positive and significant difference in asset condition category, it is recommended that a detailed investigation of the source of the difference be conducted.

Table 4-1 Comparison of Asset Condition Measured by Health Index and Field Audit

Asset	Health Index	Audit	Difference
Pad Mounted Switchgear	1.3	2.3	**1.0**
Network Vaults	1.4	2.2	**0.8**
Submersible Transformers	1.2	2.0	**0.8**
Overhead Switches - Remote Operated	2.1	1.3	**-0.8**
Underground Cable Direct Buried	2.7	2.0	-0.7
Vault Transformers	1.5	2.2	0.7
Pad Mounted Transformers	1.2	1.7	0.5
Network Transformers/protectors	1.4	1.8	0.4
Station Transformers	2.5	2.1	-0.4
Automatic Transfer Switches	2.4	2.0	-0.4
Underground Cable in Duct	2.3	2.0	-0.3
Overhead Switches – Manual	1.5	1.4	-0.1
Cable Chambers	2.1	2.1	0.0

When the condition category based on the Health Index indicates a poorer condition (a negative difference in column 3) then the likely cause is that some aspect of asset condition was captured by the Health Index and could not be evaluated by visual inspection in the audit. The more relevant and varied asset condition parameters of the heath index formulation create a much higher degree of confidence. In other words, **when the two estimates differ, the Health Index is more accurate**.

However, when the condition based on the Health Index is better than that based on the field audit (a positive difference in column 3) then there may be more reason to put some weight on the field audit results. In these cases the visual inspection found evidence of condition degradation. For these assets it is recommended that the formulation of the Health Index be reviewed to ensure that all significant condition criteria are included and weighted appropriately. For example it is possible that the electrical tracking in the pad mounted switchgear, found during the field audit, should be given more weight in the Health Index formulation.

5 CONCLUSIONS

1. Kinectrics Inc. was retained by THESL to conduct an asset condition assessment based on the Health Index methodology and a field audit of asset condition. Health Indices have been formulated for THESL's assets and evaluated using existing condition data provided by THESL. Kinectrics Inc. has provided a best estimate of asset condition based on the Health Index method or, where existing data was insufficient, an age and historical trend based method. The asset condition results have been compared to the results of field audits.

2. The Health Index method provides THESL with a tool for improved tracking of asset condition, and managing and budgeting for asset replacement and maintenance. The project has provided spreadsheets that implement the Health Index formulation.

3. Kinectrics has completed a review of the asset condition of THESL, the findings of which are detailed in the balance of this report. In the majority of cases, the condition of the assets was within the range expected for distribution assets that are well maintained. Subject to the clarifications provided in this report, in general, Kinectrics found that the records of assets provided by THESL accurately reflected the condition of the equipment in service.

4. There are indications that the condition of specific pockets of assets at THESL are deteriorating and require actions beyond routine maintenance. The indications include the increasing failure rates and poor Health Indices of some classes of asset. Direct buried underground cables are a major component that suffers from this deterioration.

5. Estimates have been made of the number of components in each asset class that will need to be replaced within the next year, in 2 to 3 years and in 4 to 10 years. Assets that require particularly significant replacement programs in the next ten years include:
    - direct buried underground cable (65%)
    - station transformers (50%)
    - pole mounted transformers (35%)
    - network transformer/protectors (32%)

6. The field audit of system condition generally found equipment to be in the same average condition as determined by the condition assessment. The exceptions included padmounted switchgear, network vaults and submersible transformers. The Health Index formulation for these assets is being reviewed in response to the audit results.

7. The Heath Index results generated in this project provide a methodology for THESL to proceed with use of the Health Index approach to asset management. For some assets the Health Indices are limited by the incompleteness of available data. This situation is expected to improve with time as more specific data is collected.

8. Age alone is not a true indicator of the condition of the assets. The condition of the asset can more accurately be represented by measurements or observations of degradation of the asset, summarized as Health Indices. Age is included as part of the Health Index as a proxy for missing data and to accommodate the transition to Health Indices.

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6 RECOMMENDATIONS

1. Asset condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data can be collected specifically designed to provide a more comprehensive indication of condition. Further data required for formulation of the Health Indices should be collected and recorded in a single, easily accessed data base.

2. A risk assessment should be conducted to prioritize the assets that require replacement.

3. The Health Index formulation for the asset classes for which the audit found a significantly poorer average condition need to be re-examined and possibly reformulated.

4. There is a need to look at some of the asset classes in considerable more granularity than was possible in this study. Considering circuit breakers for instance it would be reasonable to divide the 13.8 kV breaker asset class and look at the specifics of the air circuit breakers, oil circuit breakers, etc. It is very important to note that the asset classes used in this study do not represent a homogenous set of equipment. In addition to the variance in age there are variations in model, types, ratings, installations, environments, etc. All of these factors can potentially have impact on the condition of the individual assets, the ultimate Health Indices and the estimated replacement timing.

5. There is a need to further understand the particular failure mode of assets on the THESL system in order to assure that replacement programs are truly warranted and not a result of a repairable condition. Failure investigations are required to determine true mode of failure. This is necessary to determine if the failure could have been prevented by either maintenance or earlier replacement.

6. Further study is required to gain an improved understanding of the condition information of underground cables. For example, a cable database was constructed for this project. This data base should be completed to include age, length, cable type, and installation type.

7. Statistics should be gathered on the age at which assets were replaced in the past and why they were replaced at that age for the purpose of more comprehensively relating equipment condition to end of life.

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2007-2016
Electrical Distribution Capital Plan

January 30, 2007

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EXECUTIVE SUMMARY

Toronto Hydro-Electric System Limited ("THESL") owns and operates $1.5 billion of Capital Assets comprised primarily of an electricity distribution system, which delivers electricity to approximately 677,000 customers located in the City of Toronto. THESL is regulated by the Ontario Energy Board ("OEB"). Following its 2006 rate filing, the OEB directed THESL to prepare a capital plan.

Following the OEB's direction, THESL undertook a third party independent assessment of the condition of its assets. That asset condition study and an age-based analysis were used to prepare a detailed unit replacement plan for key asset classes over a ten year period. The unit replacement plan was translated into a capital plan for a ten-year period covering 2007-2016.

The asset condition assessment and age-based studies identify a pressing need to renew THESL's underground direct buried distribution system with modern plant. All distribution system types will require increased investment over the next ten years to deal with condition or obsolescence issues.

Approximately 30,000 units of distribution equipment are recommended for replacement over a ten-year period totalling an investment of $1.17 billion. Approximately half of that amount will be for the modernization of direct buried distribution systems. Total distribution plant investments start at a level of $102 million for 2007 and climb to a peak of $127 million for 2010-2013 before reaching a level of $108 million again in 2016.

The investments are prudent, needs-based and delivered on a just in time basis to maintain existing levels of service and reliability.

1 Introduction

1.1 Description of Toronto Hydro-Electric System Limited

Toronto Hydro-Electric System Limited ("THESL") owns and operates $1.5 billion of Capital Assets comprised primarily of an electricity distribution system, which delivers electricity to approximately 677,000 customers located in the City of Toronto. THESL is the largest municipal electricity distribution company in Canada and distributes approximately 18% of the electricity consumed in Ontario.

The business of THESL is regulated by the Ontario Energy Board ("OEB"), which has broad powers relating to licensing and standards of conduct and service and the regulation of rates charged by THESL and other electricity distributors.

1.2 Background

THESL filed an application on August 2, 2005, with the OEB pursuant to section 78 of the Ontario Energy Board Act, 1998, for orders approving or fixing just and reasonable rates for the distribution of electricity effective May 1, 2006.

In the Decision with Reasons dated April 12, 2006 regarding that application, the OEB summarized seven directions to THESL in Section 8, of which one was:

"4. Direction that the utility file comprehensive capital budget prior to the next rate case (Section 4.2);"

Section 4.2 of the same Decisions with Reasons expressed concern shared by board staff and the intervenors about the lack of a long-term capital plan with the application and the difficulty this caused in assessing the application. It stated further that

"4.7.3 The Board does agree with the intervenors that a long term plan is required and directs the utility to file such a study prior to the next rate case. THESL has advised the Board that it will be ready in mid-2006 and will be filed as soon as possible."

This document has been prepared to satisfy the OEB's direction to file a long-term capital plan.

1.3 Objective

The objective of this plan is to present THESL's yearly capital expenditure forecasts to sustain and develop its distribution plant over a ten-year time horizon.

1.4 Scope

The scope of the plan is the electric distribution plant of THESL. It covers the capital plans for the renewal of existing assets as well as the plans for new assets. The plan presents the methodology used to forecast the capital requirements for renewal as well as the capital requirements for new assets. It is intended to provide a reasonable scope of the work planned and an annual budget amount for that work for the foreseeable future. Year over year detailed plans may change based upon circumstances and vary from this plan but the long-term direction should be in alignment with the overall plan.

Therefore this plan does not present individual projects or justify individual projects. It also does not treat capital investments in meter systems, individual customer connections or reactive (unplanned) capital investments. Individual projects are identified, justified, budgeted and presented through a process described in THESL 2006 rate filing in Section A Chapter 4.

2 Asset Management

2.1 THESL Asset Management Model

THESL maintains, renews and adds assets in accordance with an asset management model. The purpose of the model is to manage all distribution plant assets through their lifecycle to meet customer reliability, safety, and service needs while optimizing the value of the assets. THESL is organizationally structured with its Asset Management Division functionally separated at the Vice-President level from the service providers to effectively apply the asset management model. Asset Management decides what should be done, and when, based upon the assessment of asset needs and then retains internal and external service providers to perform the identified tasks.

Asset Management includes capacity planning, system reliability planning and policy and standards planning. In addition it includes supply chain management, fleet, and facilities services.

2.2 Distribution Plant Capital Investment Plans

Investments to rebuild and sustain existing plant form the largest pool of distribution plant capital investments.

Despite performing maintenance according to developed plans, distribution assets do ultimately fail and reach a point where no reasonable amount of maintenance will improve the reliability, maintainability or safety of the equipment.

Performance statistics such as failure frequency, outage duration, and number of occurrences are recorded for distribution circuits and equipment. These statistics are used in addition to equipment inspection results, field staff feedback and engineering experience to identify needed improvement projects. At the same time, it may be economically and operationally beneficial to change the primary voltage serving the project area. Identified projects are scored against a pre-established set of criteria in categories including reliability, risk mitigation, and financial impact.

2.3 Distribution Plant Maintenance Investment Plans

Investment plans in distribution plant maintenance are developed using reliability-based methods. Reliability Centred Maintenance ("RCM") is designed to establish the optimal maintenance required to achieve a desired level of operational performance from an asset within its current operating context. All of THESL's distribution assets have been analyzed by multi-discipline teams.

RCM first establishes the asset functions, then identifies how the asset can fail to perform each function (termed "functional failures"), the potential causes of these failures (the "failure modes"), and the impacts these failures would have ("failure effects"). Following this analysis, it is determined whether the failure is hidden or evident, whether there are safety or environmental impacts, or whether there are operational or non-operational consequences. At each step, the team evaluates whether there is a task that can be carried out based on a failure-predicting condition, or whether a proactive cyclical task is warranted, or a scheduled replacement. All decisions are based on technical feasibility and how worthwhile the option is: a task is deemed worthwhile if the average annual cost of the maintenance is less than the average annual cost of the failure over the entire population of the asset. If, however, there are safety or environmental considerations, the proposed task is mandatory.

Once maintenance programs have been established, THESL's enterprise resource management system (Ellipse) manages the programs in a number of ways. The maintenance procedures themselves are recorded in a Standard Job, which in effect serves as a template for the Work Order to carry out a given maintenance task.

Cyclical maintenance is managed via Maintenance Scheduled Tasks ("MSTs"), which track the required dates and frequencies for the various tasks.

Planned maintenance inspection forms exist for all assets that have RCM analyses although not all forms exist in a format for in-field electronic completion. The inspection results are tied to the asset in question and stored in the Condition Monitoring module of Ellipse where it is electronically searchable.

On-condition maintenance tasks can be triggered using the Condition Monitoring functionality, which compares inspection results or performance measures against trigger values, and creates Work Orders should the triggers be exceeded.

2.4 Asset Management Objectives

The objectives of Asset Management are to invest into the distribution plant, in a financially sound manner, in order to:

- mitigate risks,
- maintain system performance (reliability), and
- maintain acceptable customer service.

2.5 Asset Management Capital Investment Strategy

Due to the nature of growth in the City of Toronto in the past and at present, sustaining capital investments predominate over development capital investments.

THESL's sustaining capital investment strategy is to identify the areas of the distribution system that are under-performing and to invest completely to replace assets in an "end-to-end" fashion so that performance is improved and no further capital investments will be needed in the area in the foreseeable future. The condition of key asset classes such as direct buried underground cable is one of the strongest drivers for the forecasted size of the sustaining capital investments as well as the "end-to-end" strategy.

In almost all cases, a "like-for-like" strategy has been adopted for the purpose of forecasting capital requirements. That is, a system is replaced with the same system such as overhead system with overhead system and underground with underground. The principal exception is that of underground direct buried cable that is replaced with underground cable in duct. Other obsolete systems and configurations do exist and require replacement with improved/enhanced systems but these have not been identified or factored into the forecast.

2.6 Sustaining Capital Forecasts

The starting point for determining sustaining capital forecasts is the forecast of unit replacements over a ten-year period. The unit replacements are then prioritized and then distributed over the ten-year period so that capital expenditures are spread as evenly as possible and that they reflect realistic allocation of human resources for work execution.

3 Sustaining Capital Requirements

The sustaining capital requirements were derived from a recommended unit replacement forecast. The unit replacement forecast was based upon the results of two unit forecast methods. The first method used is an age based asset replacement forecast model. The second is an asset condition based forecast model.

Both of the techniques are described and their associated results presented.

3.1 Age-Based Replacement Model

3.1.1 Methodology

In the age-based model, asset age is used as surrogate indicator for condition. A general industry end-of-life figure is used for each asset class and is defined as the age at which the reliability of the asset worsens significantly due to age alone. For each asset class the number of assets past the end-of-life figure are determined and the percentage of assets in that class that are beyond the end-of-life figure calculated. Using ten-year target end-of-life figures as a goal, units are replaced from oldest to newest until the target is achieved.

In the analysis, only asset classes with significant impact on reliability were targeted for a reduction in number past end-of-life. The target figure after ten years for these asset classes was chosen to be 25% of the population. These asset classes are:

- Station Switchgear and Transformers
- Underground Switches
- Underground feeder cable
- Underground distribution cable
- Pad-mounted switches
- Network transformers
- Poles

For assets that were not targeted, replacement was done to maintain the number of end-of-life assets. For a limited number of asset classes, the percentage of the population that was past its end of life age was permitted to increase.

3.1.2 Forecast

The asset classes were assembled into categories regarding function. Table 1 presents the unit replacements estimated using the age-based analysis.

Table 1 Unit replacement forecasts using age-based model

Asset Classes	Units in each year 2007-2016	Total
Station Transformers	15	147
Circuit Breakers	63	632
Switchgear Assemblies	7	71
Buildings	0	0
Network trans/protectors	83	826
Submersible Transformers	221	2,209
Vault Transformers	139	1,392
Pole Mounted Transformers	221	2,214
Pad Mounted Transformers	167	1,668
Wood Poles	2,613	26,128
Pad Mounted Switchgear	61	614
Underground Cable In Duct (km)	0	0
Underground Cable Direct Buried (km)	140	1,396
Network Vaults	0	0
Cable Chambers	129	1,292
TOTAL	4,078	40,777

3.2 Asset Condition Based Replacement Model

3.2.1 Methodology

In the asset condition-based model, the unit replacement forecasts are based upon an evaluation of asset condition against condition criteria. This method minimizes the errors of age-based methods where the age of the asset class may not be a true indicator of asset health, whether for the better or for the worse. This approach also lends itself to risk analysis of the results.

In the unit replacement forecasts the following steps were taken:

- Ascertain condition of assets

- Conduct an analysis of the risk associated with asset failure to replace higher risk components first
- Balance unit replacements forecasts for a feasible replacement plan

3.2.1.1 Asset Condition

The current condition of THESL assets was based on an Asset Condition Assessment (ACA) performed by THESL in 2006.

Asset condition was quantified by use of a Health Index for each asset class. The Health Index was assigned to each asset class based on measured criteria and field audits which defined the condition of the asset class. Health Index Scores were from 0 to 100%, with 100% representing assets that were in very good condition.

The Health Indices were defined to guide equipment replacement decisions, rather than to design maintenance plans. This was done by heavily weighting the equipment condition parameters that indicate long-term degradation that cannot be reversed by maintenance, and lightly weighting the parameters relating to maintainable aspects of the asset.

For convenience, 5 Health Index Categories were defined. Assets with Health Indices within defined ranges were grouped into Health Index Categories, identified as: Very Poor, Poor, Fair, Good, and Very Good.

The Health Index Categories could then be related to the probability that the asset would reach end of life within some future period. Assets in "very poor" condition were deemed likely to fail if not replaced in the next year, assets in "poor" condition are likely to fail in the following two years, and assets in "fair" condition are likely to fail sometime in the next ten years. Therefore, all the components in "very poor", "poor" or "fair" condition are likely to fail if not replaced within the next ten years.

A summary of the asset conditions of THESL assets is presented in Table 2.

Table 2 Summary of 2006 asset condition assessment results

Asset Class	Asset Condition					Total Population	EOL within 10 years
	Very Good	Good	Fair	Poor	Very Poor		Units (%)
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1,732	87 (5%)

Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7,490	2,140	1,070	30,709	10,700 (35%)
Submersible Transformers	3,095	3,094	1,470	420	210	8,289	2,100 (25%)
Vault Transformers	7,178	3,900	1,330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4,950	4,950	7,70	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6,388	3,194	159,700	31,940 (20%)
Overhead Switches – Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches – Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Primary Cable – XLPE in Ducts (circuit km)	N/A	2497	0%	0%	N/A	2,497	0 km (0%)
Underground Primary Cable – PILC in Ducts (circuit km)	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable – XLPE Direct Buried (circuit km)	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4,985	4,985	71	20	10	10,071	101 (1%)

3.2.1.2 Risk Analysis

The risk analysis involved an estimation of the level of concern associated with the potential failure of components within each asset class. This involved an assessment of

the probability of a failure occurring and estimating the severity of the consequences in the event of such a failure. Components in poor condition and with severe consequences upon failure would be targeted for replacement first.

The risk analysis was conducted in six steps:

- Determine the probability of failure in each Health Index Class
- Identify the Consequence types (eg. Reliability)
- Define three consequence severity grades for each risk type
- Determine the proportion of each asset class in each consequence severity grade
- Identify the dominant risk type for each asset class
- Calculate the number of components in each risk level

Since the equipment to be replaced had already been defined by the Asset Condition Assessment and the risk analysis was only being used to prioritize replacements, only relative risks were used in the analysis instead of absolute dollar values of risk.

3.2.2 Forecast

Table 3 Unit replacement forecasts using Asset Condition Model

	Units in each year										
Asset Classes	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Station Transformers	0	1	1	4	4	4	32	32	32	32	142
Circuit Breakers	0	7	7	8	8	8	14	14	14	14	94
Switchgear Assemblies	0	0	0	0	0	0	0	0	0	0	0
Buildings	0	0	0	0	0	0	0	0	0	0	0
Network trans/protectors	52	56	56	86	86	86	86	50	50	50	658
Submersible Transformers	168	179	179	225	225	225	225	225	225	225	2101
Vault Transformers	0	5	5	190	190	190	190	190	190	190	1340
Pole Mounted Transformers	856	910	910	1146	1146	1146	1146	1146	1146	1146	10698
Pad Mounted Transformers	11	55	55	88	88	88	179	179	179	179	1101
Wood Poles	1916	2396	2396	3604	3604	3604	3604	3604	3604	3604	31936
Overhead Switches - Remote Operated	0	0	0	1	1	1	25	25	25	25	103
Pad Mounted Switchgear	1	4	4	6	6	6	10	10	10	10	67
Automatic Transfer Switches	0	0	0	0	0	0	18	18	18	18	72
Underground Primary Cable In Duct (circuit km)	24	24	24	47	47	47	47	47	47	47	401
Underground	133	140	150	129	129	129	112	87	70	70	

Primary Cable Direct Buried (circuit km)											1149
Network Vaults	0	1	1	8	8	8	8	8	8	8	58
Cable Chambers	9	10	10	22	22	22	4	4	4	4	111
TOTAL	3170	3788	3798	5564	5564	5564	5709	5648	5631	5631	50067

3.3 Analysis

A comparison of the total number of units replaced in a ten year time-span using the two methods may be found in Table 4.

Table 4 Comparison of age-based and asset condition based unit replacement forecasts

Asset Classes	Age based analysis 2007-2016 Total	Asset Condition based analysis 2007-2016 Total
Station Transformers	147	142
Circuit Breakers	632	94
Switchgear Assemblies	71	0
Buildings	0	0
Network trans/protectors	826	658
Submersible Transformers	2,209	2,101
Vault Transformers	1,392	1,340
Pole Mounted Transformers	2,214	10,698
Pad Mounted Transformers	1,668	1,101
Wood Poles	26,128	31936
Overhead Switches – Remote Operated	N/A	103
Pad Mounted Switchgear	614	67
Automatic Transfer Switches	N/A	72
Underground Cable In Duct (km)	0	401
Underground Cable Direct Buried (km)	1,396	1,149
Network Vaults	0	58
Cable Chambers	1,292	111
TOTAL	40,777	50,067

The two methods produced similar results for the following asset classes:

- Station transformers
- Submersible transformers
- Vault transformers
- Underground direct buried cable

The two methods produced different results for the following asset classes:

- Circuit breakers
- Switchgear assemblies
- Pole mounted transformers
- Pad-mounted transformers
- Overhead switches
- Pad-mounted switchgear
- Automatic transfer switches
- Underground cable in duct
- Cable chambers

In the case of circuit breakers and switchgear assemblies, the difference between the two methods can be explained by the condition-based analysis' lack of ability to capture obsolescence issues. The age-based analysis is limited to the age of the equipment and therefore captures obsolescence issues.

It is unusual for a condition-based analysis to direct more unit replacements than an age-based approach. The differences may be explained by a too long a life span predicted for pole-top units. In addition, condition data is typically not collected for pole-top units as they are not easily accessible for maintenance. These two factors may have led to the stated difference.

For automatic transfer switches and underground cable in duct, the condition-based analysis identified replacement needs that were not captured by the age-based analysis.

A significant discrepancy exists between the two methods with respect to cable chambers. The condition-based analysis was believed to provide more realistic results in this instance as civil structures in good environments can last substantially longer than if only an age-based assessment was carried out.

3.4 Recommended Unit Replacement Forecast

The results presented in 3.1.2 and 3.2.2 were compared with differences explained in 3.3. In general, the condition-based method was used to guide the unit replacement forecast unless a valid reason was found to deviate as was discussed in 3.3. The results were examined in light of the fact that asset classes work in groups and that it is cost effective

to replace assets in groups. The results were also examined in light of execution feasibility by THESL. Based upon these analyses, the recommend unit replacement forecast is listed in Table 5.

Table 5 Recommended unit replacement forecast

	Units in each year										
Asset Classes	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Station Transformers	6	6	6	7	7	7	7	6	5	5	61
Circuit Breakers	23	22	23	25	25	25	25	23	21	21	232
Switchgear Assemblies	4	4	4	4	4	4	4	4	4	4	40
Buildings	0	0	0	0	0	0	0	0	0	0	0
Network trans/protectors	55	59	64	69	69	69	69	64	58	58	634
Submersible Transformers	327	597	635	688	688	688	688	635	587	587	6118
Vault Transformers	33	25	26	29	29	29	29	26	24	24	273
Pole Mounted Transformers	452	341	363	393	393	393	393	363	335	335	3761
Pad Mounted Transformers	109	172	180	193	193	193	193	180	169	169	1750
Wood Poles	1431	1080	1149	1243	1243	1243	1243	1149	1061	1061	11902
Overhead Switches - Remote Operated	50	50	50	50	50	50	50	50	50	50	500
Pad Mounted Switchgear	30	56	59	64	64	64	64	59	55	55	571
Automatic Transfer Switches	5	5	5	5	5	5	5	5	5	5	50
Underground Cable In Duct (conductor km)	77	50	53	58	58	58	58	53	49	49	561
Underground Cable Direct Buried (conductor km)	124	230	245	266	266	266	266	245	226	226	2361
Network Vaults	10	10	10	10	10	10	10	10	10	10	100
Cable Chambers	30	30	30	30	30	30	30	30	30	30	300
TOTAL	2766	2736	2902	3132	3132	3132	3132	2902	2690	2690	29214

3.5 Sustaining Capital Requirements

Table 5 was further simplified by grouping assets that work together as part of the distribution system and then estimates generated for the unit replacements of assets in each group. THESL forecasts that it will need to make sustaining capital investments of approximately $1.2 billion over the next ten years to maintain asset condition. Nearly

half will need to be invested to replace underground direct buried distribution systems. It also forecasts that the rest of its underground distribution system and its overhead system will need $210 million and $182 million respectively over the next ten years. Investments in transformer stations, municipal stations and network electrical distribution systems will require investments of $95 million, $60 million, and $58.5 million respectively over the next ten years. The ten-year forecast for sustaining capital per distribution group is presented in Table 6.

Table 6 Sustaining capital requirements 2007-2016

Group	Sustaining Capital Required per Year ($ 000,000)										Total	% of total
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
Underground Direct Buried Distribution	29.6	55.0	58.5	63.5	63.5	63.5	63.5	58.5	54.0	54.0	564	50
Underground Non-direct Buried Distribution	28.9	18.7	19.9	21.6	21.6	21.6	21.6	19.9	18.4	18.4	210	17
Overhead Distribution	22.1	16.5	17.6	19.1	19.1	19.1	19.1	17.6	16.2	16.2	182	15
Network Systems	5.1	5.5	5.9	6.4	6.4	6.4	6.4	5.9	5.4	5.4	58.5	5
Transformer Stations	9.4	8.8	9.4	10.2	10.2	10.2	10.2	9.4	8.6	8.6	95	8
Municipal Stations	7.0	5.5	5.9	6.4	6.4	6.4	6.4	5.9	5.4	5.4	60	5
Total	102.1	110.0	117.0	127.0	127.0	127.0	127.0	117.0	108.0	108.0	1,170	100

The recommended investments focus on the key asset classes that require replacement and focus investments in proportion to the need identified in the Asset Condition Assessment and age-based studies. The recommended plan is certain for the period 2007-2010. An Asset Condition Assessment will be required after a few years of progress in the recommended plan in order to make any adjustments to the plan given data uncertainty or a difference in actual component performance as compared to predicted performance.

4 Development Capital Requirements

The distribution system must have adequate capacity to meet the peak demand requirements placed on it under both the normal operating state and under recognized contingency conditions. This must be done in a safe, secure and reliable manner that complies with standards and criteria based on good utility practices.

In addition, distribution system adequacy depends upon transmission system adequacy and delivery point performance of THESL's transmission system provider, Hydro One Networks Inc.

Development capital is capital needed for new or upgraded distribution and transmission facilities. Development capital projects:

- provide adequate capacity at the distribution level to deliver electricity to customers
- provide adequate transfer capability at the distribution level to deal with contingencies at the feeder and or station level
- connect customers to the distribution system
- are used to comply with its distributor licence
- provide capital contributions to THESL's transmission service provider in accordance with the terms of the Transmission System Code

4.1 Methodology

An adequacy assessment of distribution facilities up to and including the transmission/distribution boundary is conducted yearly by THESL for periods of up to ten years into the future. The results that affect or involve the transmission service provider are discussed with the transmission service provider and joint planning is done to remedy any identified issues.

Joint studies with the transmission service provider are conducted on the adequacy of the transmission facilities to the THESL transmission/distribution boundary. These results are then discussed between the two parties and further work or proposals to the OEB for projects to remedy transmission adequacy are developed.

The following identified needs and plans are presented along the same lines as they are studied.

4.2 Transmission

In 2003, a joint HONI and THESL Planning Study identified the need for transmission reinforcement to supply forecast load demand in the central Toronto area by summer 2008. This area is supplied at 115 kV by one auto-transformer station at Leaside in the east and one at Manby in the west. It includes the city's commercial and financial districts, university health care system, as well as developing waterfront areas.

The Independent Electricity System Operator's (IESO) 18-Month Outlook issued on December 22, 2005, highlighted the need for new supply and transmission facilities in the Greater Toronto Area (GTA). The outlook stated that the transmission system serving central Toronto was at or near capacity during peak periods in the summer of 2005. The loading of this system is reaching the point at which there is no longer the necessary redundancy available to reliably meet demand under all conditions.

In August 2006, a confidential and privileged HONI and THESL Planning Study was completed to:

- review the adequacy of the existing transmission system based on the 2006 THESL forecast and the provincial demand reduction initiatives;
- identify impact of high impact contingencies, and
- identify transmission facilities required to meet area needs over both the near (2006-2011) term and the long (2011-2021) term

The main issue for supply to the central Toronto area is the critical nature of the area's load and the adequacy of the transmission facilities. The two 230kV transmission corridors – Cherrywood TS to Leaside TS and Richview TS to Manby TS - and the Leaside 230/115kV autotransformer serving the central area are at or are approaching capacity limits. There are also internal transmission limitations on the 115kV system that require immediate relief.

A second but equally important issue is the concern about the effect of a catastrophic event at either the transmission or the delivery point level. Even though the probability of such an event happening is relatively low, the resulting power interruption has the potential to have a great impact on Toronto and the Province of Ontario. At the transmission level, there is limited transfer capacity between the Leaside and the Manby supply areas. A loss of an auto-transformer station will lead to a prolonged outage.

At the delivery point level, there is virtually no transfer capability between stations in the downtown core. Aside from the limited ability at John/Windsor and Terauley, no built-in means exists for transferring circuits from a bus to another bus within stations in the downtown core.

The following projects were identified:

Part 1 – Facilities required by 2009/2010 to address capacity issues:
• Leaside to Birch Junction transmission reinforcement
• Richview to Manby transmission reinforcement

These two projects have been identified by HONI in their transmission rate filing of September 12, 2006, however both are under review

4.2.1 Capital Requirements

The following Table 7 is the forecasted capital requirements for transmission needs to 2016, provided both projects proceed as known at this time.

Table 7 Transmission capital requirements

Description	Capital Contribution to HONI ($million)	Other THESL direct costs ($million)
Leaside to Birch Junction transmission reinforcement	60	0
Richview to Manby transmission reinforcement	8	0

Note that the capital contributions are estimates and could decrease depending upon the classification of the projects as being of partial sustaining capital nature and whether capital contributions are to be shared amongst benefiting transmission customers. In addition, distribution solutions may be available to post pone the transmission investments.

4.3 Stations

THESL evaluates the bus capacity adequacy of all transformer station busses supplying its distribution system assets on a yearly basis. The focus is the capacity at the transmission/distribution boundary. This study does not focus on transmission planning issues directly nor does it reflect transmission capacity limitations unless those were directly reflected in the bus capacity limits provided by transmission service provider.

The latest evaluation, dated February 2006 revealed the following significant capacity issues:

Central Toronto

Four out of the five stations serving the central Toronto area (downtown) will have inadequate bus capacity during the next ten years. These stations are Cecil, Esplanade, Terauley and John/Windsor. The John/Windsor station is the largest station and it serves some of Canada's most important businesses.

THESL will require a new station (Roundhouse) over the next ten years in the neighbourhood of John/Windsor in order to meet future load and to deal effectively with contingencies involving supply to and from the central stations. The station would be constructed by HONI and have an ownership structure and transmitter/distributor demarcation points similar to the existing central Toronto stations.

West Toronto
At present Manby station is at capacity, and it is anticipated that, in ten years time, there will be inadequate station capacity at area stations Runnymede and Fairbank.

THESL will require a new station over the next ten year in the neighbourhood of Manby in order to meet future load in the west area. The station would be constructed by HONI and have an ownership structure and transmitter/distributor demarcation point similar to that present in the west stations.

4.3.1 Capital Requirements

The following is the estimated capital requirements for station needs to 2016.

Table 8 Station capital requirements

Description	Capital Contribution to HONI ($million)	Other THESL direct costs ($million)
Roundhouse TS	28	5
New West Station	6	0

4.4 Distribution

There are no significant development costs forecasted for the distribution system that would not be funded by capital contributions from new or expanding customers.

5 Capital Plan

5.1 Sustaining Capital Investments

The following Table 9 summarizes the yearly sustaining capital requirements to 2016.

Table 9 Sustaining Capital Requirements Summary

Group	Sustaining Capital Required per Year ($ 000,000)										Total
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
Underground Direct Buried Distribution	29.6	55.0	58.5	63.5	63.5	63.5	63.5	58.5	54.0	54.0	564
Underground Non-direct Buried Distribution	28.9	18.7	19.9	21.6	21.6	21.6	21.6	19.9	18.4	18.4	210
Overhead Distribution	22.1	16.5	17.6	19.1	19.1	19.1	19.1	17.6	16.2	16.2	182
Network Systems	5.1	5.5	5.9	6.4	6.4	6.4	6.4	5.9	5.4	5.4	58.5
Transformer Stations	9.4	8.8	9.4	10.2	10.2	10.2	10.2	9.4	8.6	8.6	95
Municipal Stations	7.0	5.5	5.9	6.4	6.4	6.4	6.4	5.9	5.4	5.4	60
Total	102.1	110.0	117.0	127.0	127.0	127.0	127.0	117.0	108.0	108.0	1,170

5.2 Development Capital Investments

The following Table 10 presents the development capital investment requirements.

Table 10 Development Capital Requirements Summary

	Development Capital Required per year ($ 000,000)										Total
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
Transmission	0	34	34	0	0	0	0	0	0	0	68
Stations	0	0	0	7	14	7	0	0	0	6	34
Distribution	2	2	2	2	2	2	2	2	2	2	20
Total	2	36	36	9	16	9	2	2	2	8	122

5.3 Consolidated Capital Requirements

The following Table 11 presents the consolidated capital investment requirements for the distribution system.

Table 11 Consolidated Capital Summary

	Capital Required per year ($ 000,000)										Total
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	
Sustaining	102.1	110.0	117.0	127.0	127.0	127.0	127.0	117.0	108.0	108.0	1,170
Development	2	36	36	9	16	9	2	2	2	8	122
Total	104	146	153	136	143	136	129	119	110	116	1,866

The Strategic Counsel

A Report to

Toronto Hydro-Electric System Limited (THESL)

Findings from Customer Research: Perceptions of the State of the Electricity System & the Need to Upgrade

June 2007

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The Strategic Counsel

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The Strategic Counsel

I. Executive Summary

Executive Summary

The Strategic Counsel was contracted by Toronto Hydro-Electric System Limited (THESL) to undertake a two-part program of customer research aimed at understanding customers' views on the state of the electricity distribution system (EDS) in Toronto. A telephone survey among 1000 residential and 400 small commercial customers was carried out in late March and extended into early April, 2007. The sampling design ensured that over-samples were conducted in targeted areas across the City identified as having higher than average outage frequencies. Details of the sampling and methodology are contained in Section II of this report along with a demographic profile of respondents to the survey. The survey was followed by a series of five focus group discussions among residential customers only. Participants to the groups were not necessarily those who had participated in the survey. To the extent possible, they represented a cross-section of THESL customers, with three of the groups comprising customers from those areas of Toronto experiencing higher outage frequencies.

The findings from the survey and the focus groups offer important insights with respect to customers' priorities for infrastructure improvements, their perceptions of the state of the EDS, the priority placed on modernizing or updating the EDS relative to other infrastructure concerns as well as their support for investments the EDS infrastructure.

The main findings from both the quantitative and qualitative phases of the research are summarized below.

A. Key Findings

- The state of Toronto's infrastructure is a key concern for a significant segment of Toronto Hydro customers. When asked in an unprompted fashion to identify the most important issues for the Greater Toronto Area (GTA), just over one-third (34%) of residential customers and about the same number of business customers (33%) did mention infrastructure generally, transportation and public transit as an issue that the municipal and provincial governments should focus on;

- The plurality of both residential (43%) and business (40%) customers rate the state of Toronto's infrastructure, including roads, transit, water, sewers and the electricity distribution system) as "fair;"

- While the state of the electricity distribution system is not a burning issue for residential and business customers, significant percentages within both these customer segments (62% of business customers; 59% of residential customers) did suggest that a priority should be placed on improving the system. At the same time, it was clear from the results of the telephone survey and in focus groups that public transit as well as roads, highways and bridges were higher priorities, based on the number of respondents who offered a rating of either 5, 6 or 7 on a 7-point scale, where 1 is a "low priority," 7 is a "high priority" and the midpoint 4 means the item is a "moderate priority'"

- Focus group discussions reinforced the findings from the telephone survey in that participants, on a completely unprompted basis, identified a wide range of infrastructure priorities in their communities from transportation infrastructure to health care, parks, recreational facilities and green spaces. At the same time, in all groups at least one or two participants identified "hydro" or the electricity system as a concern;

- It is clear from the focus group discussions that it is the most visible and "felt" aspects of the city's infrastructure that garner attention from residents and small business owners. Thus, transit, roads, waste management, recycling, communal spaces and public services tend to be the focus of a discussion on the topic of infrastructure deficits or priorities;

- Based on the results of the survey and the findings from the focus group discussions, repairs to the EDS could clearly be classified as a mid-level or second tier infrastructure priority;

- There is general agreement that the state of the EDS is in disrepair. Just over half of customers (54% of residential customers; 62% of small business customers) agree with the statement that "in many parts of Toronto, the electricity distribution system is old and in need of repair." The percentage level of agreement with this statement is substantially higher among those residing in so-called "problem areas" (66% of residential customers in areas experiencing higher outage frequencies agree with the statement);

- Moreover, a significant majority of residential (86%) and small business customers (87%) place a high importance on the EDS as contributing to Torontonians' quality of life, although substantially fewer (35% of residential customers; 37% of small business customers) are confident that the EDS infrastructure is adequate to meet electricity demand in the next few years;

- In line with this, large numbers of residential customers (72%), including those residing in areas experiencing higher outage frequencies (77%), anticipate that "brown-outs and black-outs will occur more frequently in the near future." While a majority of small business customers (57%) also agree that this is likely to be the case, they are far fewer in number as compared to residential customers;

- Many customers are predominantly concerned with the demands that anticipated population growth in the city will place on the EDS. Fully four-in-five (80%) of both residential and small business customers alike agree that "given the city's anticipated population growth, new buildings and increased technology use, I think the city's electricity distribution system will require further investments to keep pace;"

- While customers are concerned about the level of investment required, and possible cost overruns, especially in light of rising electricity costs, there is strong support for investing to modernize and upgrade Toronto's EDS (85% of residential customers; 90% of small business customers). In fact, when specifically asked whether significant investments should be made in the EDS or whether investments would likely cost to much relative to the improvements in reliability, the overwhelming majority of residential and small business customers held to the former position (63% of residential customers; 66% of small business customers).

II. Objectives and Methodology

Objectives and Methodology

A. Research Objectives

THESL commissioned *The Strategic Counsel* (TSC), a national professional public opinion and market research firm, to undertake a two-part program of research among its customers. The research was undertaken in order to better understand customers' views on the current state of Toronto's electricity distribution system (EDS) within the context of the broader slate of infrastructure priorities.

A telephone survey of a representative group of residential and small business customers preceded a series of focus groups. Combined, the findings from these studies produced a comprehensive picture of customers' views on this topic. A more detailed description of the approach and methodology is contained in the section that follows.

The specific objectives of the research were to:

- Ascertain overall perceptions of the state of the city's infrastructure, in general;
- Determine the relative positioning of repairs to the EDS among a broader range of possible municipal infrastructure priorities;
- Assess the level of concern regarding brown-outs or black-outs; and
- Obtain feedback on the sense of urgency of investments in electricity distribution infrastructure as well as the extent of support for investments in the EDS relative to other infrastructure priorities.

B. Methodology

1. Telephone Survey

A survey of 1,000 residential customers was completed between March 29th and April 9th, 2007. This was complemented by a parallel survey of 400 small business customers which was undertaken between April 2nd and April 10th, 2007.

The sample of 1,000 residential customers included an over-sample of 400 customers with addresses in problem areas. Similarly, the final sample of 400 small business customers also comprised an over-sample of 150 with addresses located in problem areas. Customers in problem areas are those identified by Toronto Hydro as having addresses in areas with some of the highest system problems (those areas of the city which are experiencing higher-than-normal outage rates).[1]

Survey Length, Profile of Respondents and Response Rates

The survey, included as Appendix A, was approximately five to seven minutes in length and comprised mostly closed-ended questions, providing respondents with a series of pre-defined response categories from which to choose. Residential customers were screened to ensure that the respondent was the individual within the household that was primarily responsible for paying the hydro bill. This was also the case for small businesses, whereby the individual responding to the survey was either the owner/operator, manager or the person responsible for dealing with hydro bills and/or Toronto Hydro on a regular basis.

The response rate among residential customers was 28.2% and just slightly lower among small business customers (24.5%). This is calculated as the number of sampled units completing the survey divided by the number of all sampled units eligible to complete the survey. The complete call dispositions showing the number of calls made in addition to non-responses, including refusals and not-in-service numbers, is shown as Appendix B. Notably, these response rates are somewhat higher than average for most telephone surveys, especially given declining trends in response rates for all modes of surveying, including telephone. It should be noted that substantial research into trends in response rates and non-response bias has shown that there is little evidence that the results obtained are biased by the presence of non-response.

Sample Distribution and Associated Margin of Error

To ensure a statistically significant number of interviews were conducted with residents and small businesses in the problem areas noted above, TSC conducted an over sample of 400 residential customers and 150 small business customers residing or having their businesses located in these areas.[2]

The tables below present the distribution of completed surveys and the associated margin of error at the 95 per cent confidence level.

Residential Customers	Unweighted Sample	Margin of Error
Main Sample	600	4.00%
“Problem” Areas (Over sample)	400	4.90%
TOTAL	1000	3.10%

[1] Certain areas of Toronto served by direct-buried underground cable are experiencing higher outage frequencies due to deterioration of the buried cable.

Small Business Customers	Unweighted Sample	Margin of Error
Main Sample	350	5.24%
"Problem" Areas (Over sample)	150	8.00%
TOTAL	400	4.90%

Survey results are presented with an associated margin of error and a confidence level, both expressed in percentage terms. The margin of error is calculated based on the overall population (i.e. all Toronto Hydro residential and small business customers) and the size of the survey sample. The larger the margin of error, the less confidence the reader or analyst should have that the survey results can be accurately extrapolated to the larger population. For the survey of THESL residential customers, the margin of error is 3.1 per cent at a 95 per cent level of confidence. This means that if the survey were conducted 100 times, the data would be within 3.1 percentage points above or below the percentage reported in the survey findings 95 of the 100 surveys.

Weighting the Data

As mentioned above, TSC conducted an over-sample in certain "problem" areas in the Toronto region to ensure a statistically significant number of surveys were completed in those regions. This allowed for an analysis of those regions on their own and for comparative analysis between affected and non-affected areas, with a lower associated margin of error.

However, when analysing the data overall, it must be weighted to correct for these distributions in the sample data (i.e. the over-sampling) to approximate those of the population from which it is drawn. In this case, the problem areas were over-sampled in the study and therefore were weighted down to their proper proportion (according to Toronto Hydro customer list). This ensures the final results are not biased by including an over-representation of residents or small businesspeople from those areas with reliability issues.

A Profile of Survey Respondents

A demographic profile of respondents is shown in the Chart 1 below:

Demographic Profile of Survey Respondents

Business Survey	Total Sample
n=	400
	%
Number of employees	
1-50	88
51-250	8
251 +	4
Job Title	
Manager/supervisor	48
Owner	22
President/VP/CEO/Director	15
Other	15
Business Sector	
Retail/Service/Food Service	36
Manufacturing	12
Property Mgt./Real Estate	11
Professional Services	10
Not-for-profit / religious	5
Transportation	3
Construction	3
Wholesale/Warehouse	3
Health Services	2

Residential Survey	Total Sample
n=	1000
	%
Gender	
Male	48
Female	52
Age	
18-34	14
35-44	21
45-54	20
55 +	40
Annual Income	
Under $50,000	30
$50,000 to $99,999	31
$100,000 or greater	22
Education	
High school or less	21
Some post-secondary	8
Completed college	22
Completed university	30
Post-graduate degree	17
Living situation	
Own my home	73
Renting	22

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2. Focus Groups

The telephone survey of THESL customers was followed by a series of five focus groups, one each conducted among residential customers of Etobicoke, North York and Scarborough and two groups among residents of Toronto proper. The decision was made to recruit only residential customers given that the survey results revealed few significant differences in the opinions of residential and small business customers. The segmentation of groups, by area, provided an opportunity to identify differences, if any, in the views of a cross-section of customers residing in areas where system reliability is an issue versus other less affected areas.

Focus groups are often employed in conjunction with surveys as a means of further exploring a particular topic and illuminating the findings from quantitative research. They provide an opportunity to hear from

customers, in their own words, while surveys often limit respondents to choosing among a discrete set of response categories. The semi-structured format and open-ended nature of a focus group often yields insights which provide a useful backdrop or context to survey results. This type of qualitative research often lends an additional layer of depth to the interpretation of survey results.

Readers should however be cautioned that, unlike the results of the survey which are statistically valid and based on the application of a stratified sampling design, the findings from qualitative research cannot be extrapolated or generalized to the broader population of Toronto Hydro residential customers. They do, however, offer important insights which help to further explain and augment the findings from the survey.

Each focus group comprised approximately eight to 10 participants recruited from lists of Toronto Hydro customers residing in these areas. The lists were provided by Toronto Hydro and contained only the information required to recruit customers from specific areas within the City. All other personal and account information was deleted from the file before being provided to *The Strategic Counsel*.

The recruiting script is attached as Appendix C. Participants were recruited to ensure a reasonable cross-section of customers by age, occupation and income levels. In addition, all participants were homeowners. Renters were excluded from the groups.

Both the recruiting script and the moderator's guide were developed in close collaboration with Toronto Hydro. The guide, attached as Appendix D, contains a series of open-ended questions. The two-hour discussion was structured such that participants were first asked to identify the key infrastructure priorities in their communities before being asked specifically about the state of the EDS. Thus, as is common practice in focus group discussions, the conversation became more focused on the EDS, but provides a backdrop which is useful in understanding the context in which customers think about infrastructure generally and the EDS in particular.

III. Detailed Findings

Objectives and Methodology

A. Most Important Community Issue

When asked, in an unprompted fashion (i.e. respondents answered the question in their own words and their responses were subsequently grouped into categories as shown in the chart below), what the most important issues are in the Greater Toronto Area (GTA), residential and small business customers of THESL cited an array of issues. As shown in Chart 2, general concerns about infrastructure as well as specific mentions of transportation or public transit topped the list for both customer segments (34% of residential and 33% of small business customers). Additional items put forward as those that customers of Toronto Hydro feel their municipal and provincial governments should focus on most include a series of issues that have dominated the public agenda for over a decade, including taxes, health care and education, as well as those, like the environment as well as crime, safety and security, which have surfaced more recently as community priorities.

Hydro is specifically mentioned as a priority among seven per cent of residential customers and one per cent of small business customers, with a particular emphasis on the cost of electricity.

Chart 2: Most Important Community Issue – Telephone Survey

Most Important Issue for the GTA: Infrastructure, Environment, Taxes, Health Care, Education

	Residential Customers	Business Customers
n=	1000	400
	%	%
Infrastructure / transportation / public transport	34	33
Environment	25	15
Taxes	21	30
Health Care	15	13
Education	14	9
Homelessness / poverty	10	5
Crime / safety / security	9	13
Reducing the cost of Hydro / rising cost of Hydro	7	1
Public spending / public funding	6	7
Sanitation / garbage	4	11
Child care / daycare	3	1
Employment / wages / labour issues / cost of living	2	5

Q.1 First, as a resident of/business located in the Greater Toronto Area what are the most important issues for you, that is, those issues that you feel the municipal and provincial governments should focus on most? Anything else?
Base: Total respondents (residential customers n=1000; business customers n=400)
Note: Response may add to greater than 100%. Multiple responses were permitted.

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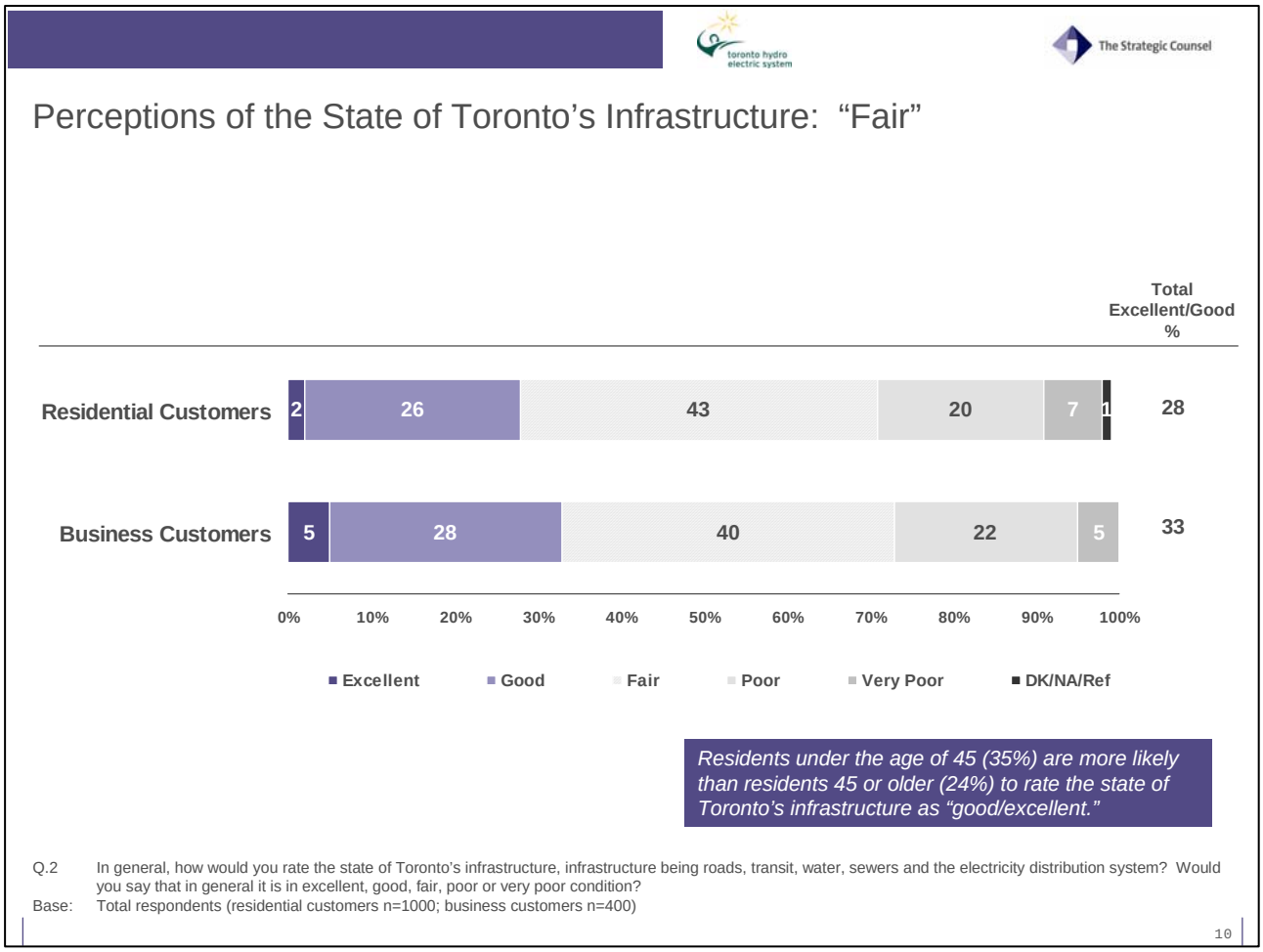
There are no significant differences between those customers in "problem" and non-problem areas of Toronto with respect to the identification of priority issues.

B. Assessments of the State of Toronto's Infrastructure

Customers of Toronto Hydro are clearly concerned about the state of infrastructure in their community (Chart 3). When asked how they would rate the state of Toronto's infrastructure, encompassing roads, transit, water, sewers and the electricity distribution system, one-third or fewer of both small business (33%) and residential (28%) customers offered a rating of either "excellent" or "good." The plurality (43% of residential customers; 40% of small business customers) rated the current state of Toronto's infrastructure as "fair" with just over one-quarter of respondents in each group (27% for both residential and small business customers) giving a rating of either "poor" or "very poor."

Chart 3: State of Toronto's Infrastructure – Telephone Survey



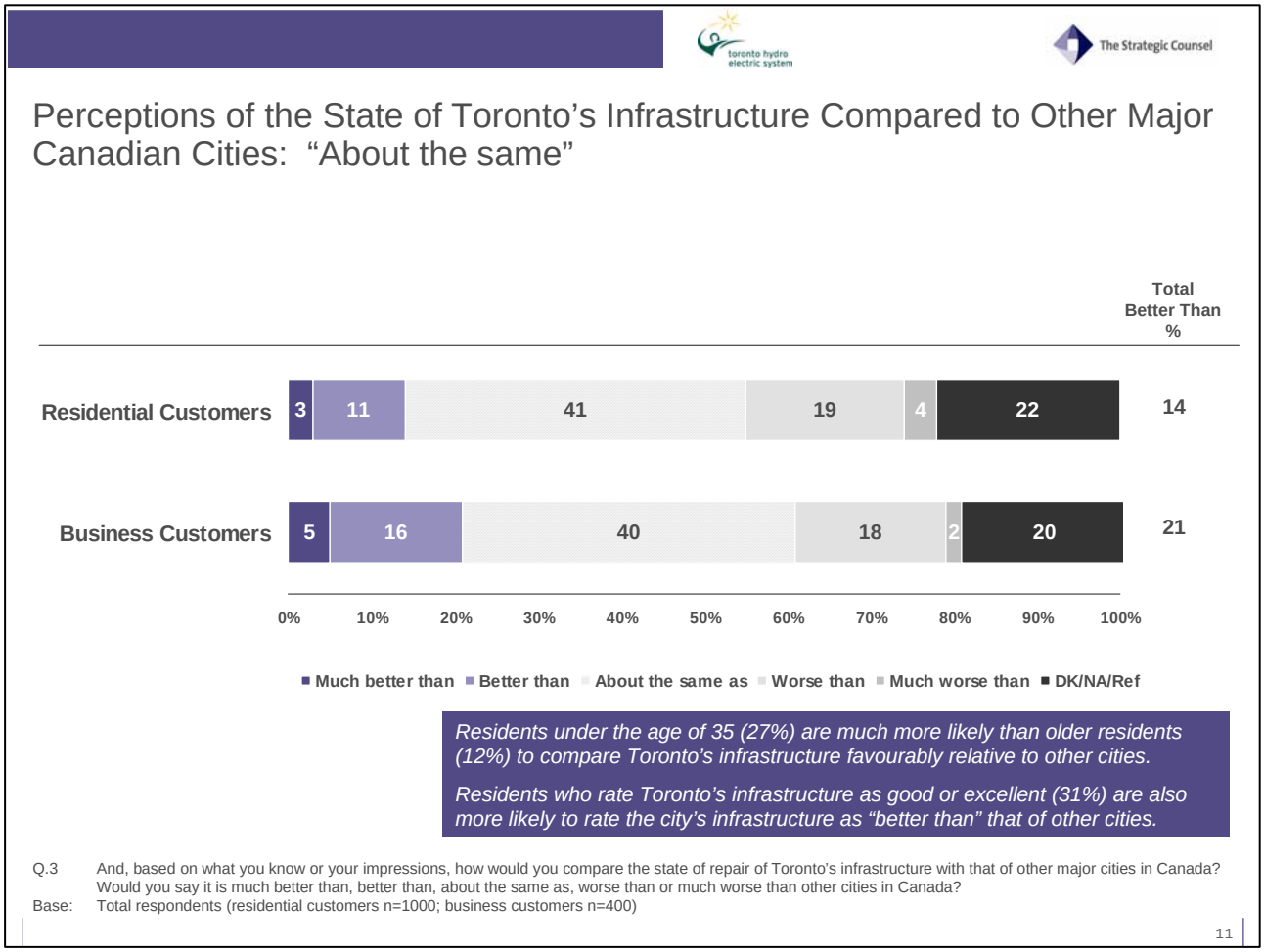
Comments from participants in the focus groups were in line with results from the survey. In all groups, participants were also inclined to rate the state of infrastructure in their community as "fair." Elaborating further on this assessment, focus group participants noted that, while much of the infrastructure functions relatively well, there is nevertheless a perception that improvements are necessary, if not urgent in some cases, and possibly long overdue.

Participants define infrastructure as "the connective tissue of a community," stressing the importance of those elements which comprise their built environment. They also described the state of infrastructure as "aging" or "crumbling" and expressed some concern that the current system of infrastructure was not designed to support a rapidly growing city.

At the same time, a plurality of residential (41%) and small business (40%) customers suggested that the state of Toronto's infrastructure is no better or worse compared to infrastructure in other major cities in

Canada (Chart 4). A small number, about two in ten in each customer segment, didn't offer an assessment of how Toronto's infrastructure compares to other cities.

Chart 4: Comparison of Toronto to Other Major Canadian Cities With Respect to the State of the Infrastructure – Telephone Survey



C. Identifying Infrastructure Priorities

When asked to ascribe a level of priority to each of seven components of Toronto's infrastructure, as they were put forward to respondents to the survey, residential and small business customers placed the highest priority on transportation and transit.

On a scale of 1 to 7, where 1 means it is a low priority, 7 means it is a high priority and the mid-point 4 means it is a moderate priority, just over eight in ten residential customers (82%) ranked the public transit system as a priority, combining those who offered a rating of either 5, 6 or 7 on the 7-point scale (Chart 5a). About the same numbers of small business customers offered the same rating with regard to roads, highways and bridges (Chart 5b).

Over half of residential (59%) and small business (62%) customers ascribed a priority to improving the electricity distribution system. Among those residential customers residing in "problem" areas, even greater numbers (73%) indicated that the electricity distribution system was a priority for improvement, 14 points higher than the average.

Chart 5a: Relative Rankings of Infrastructure Priorities: Residential Customers – Telephone Survey

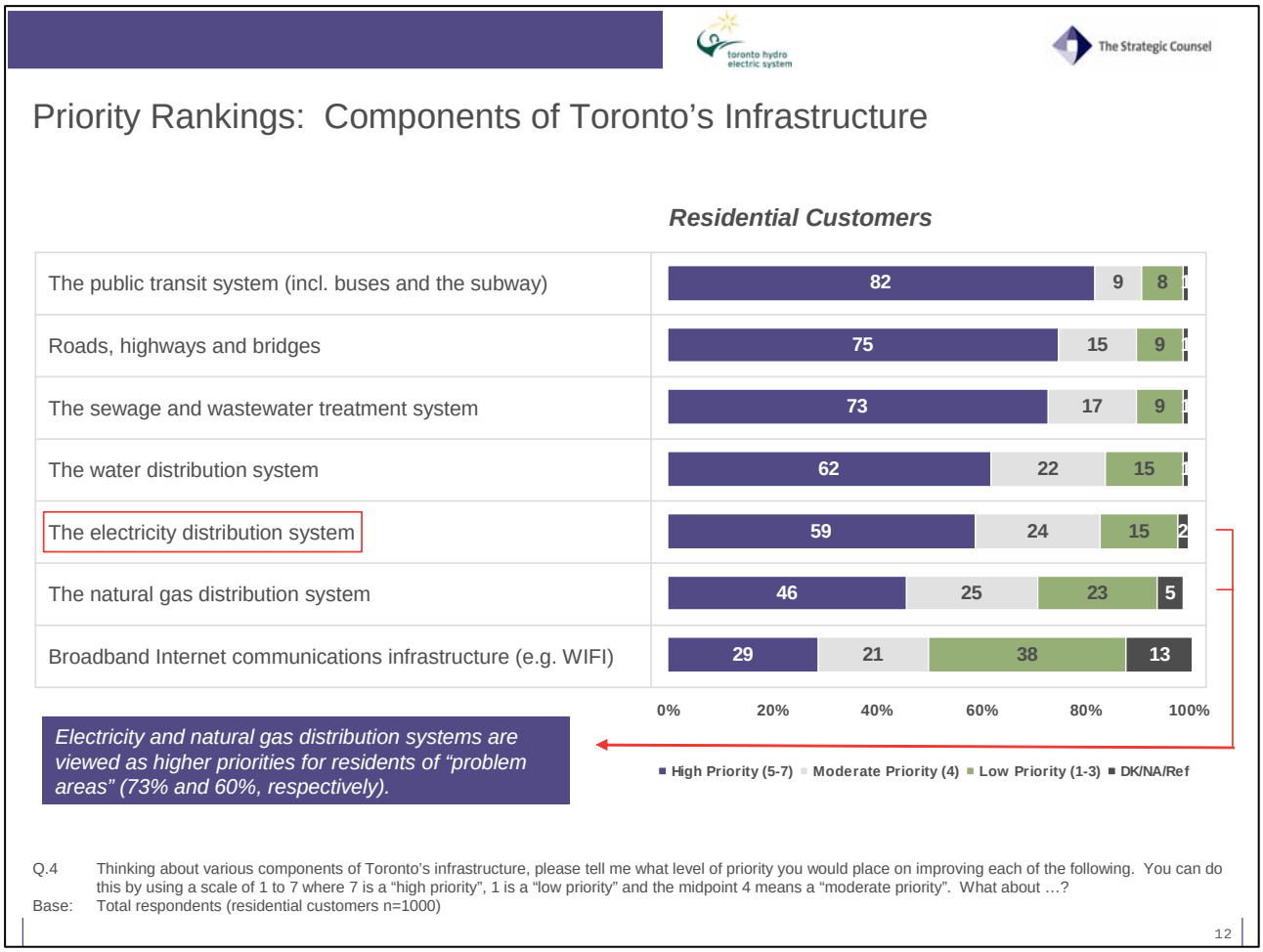
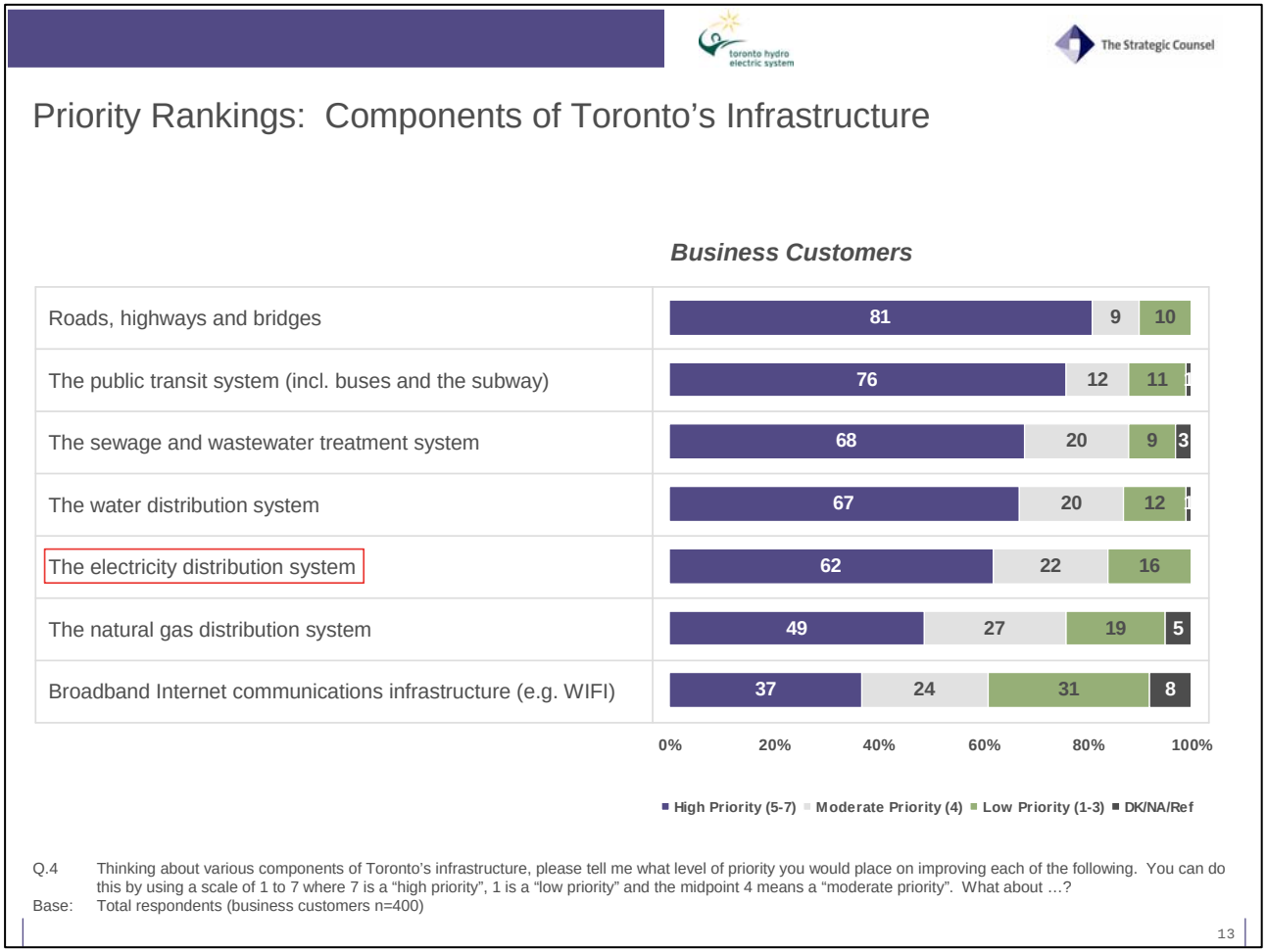


Chart 5b: Relative Ranking of Infrastructure Priorities: Small Business Customers – Telephone Survey



In focus groups, participants were not directed, as in the survey, to assess a priority to a pre-determined series of items reflecting key components of the city's infrastructure. Rather, they were asked in a non-directed fashion to identify what they viewed as the key infrastructure priorities in their communities. A wide range of responses were offered reflecting many of the same issues referred to in the survey.

Notably, while upgrading the electricity distribution system (EDS) was not necessarily a top-of-mind priority for most focus group participants at this early stage of the discussion, it could be said to be a mid-level priority. In all groups, including the groups in Toronto proper, at least one or two individuals did identify the EDS as a key infrastructure priority. Focus group participants residing in affected areas such as Etobicoke and especially North York were more likely to raise the issue of the EDS as a high priority very early in the discussion of infrastructure priorities. Moreover, with respect to its relative position as a priority among a range of other infrastructure issues, concerns about the EDS heightened during the course of the two-hour discussion as participants contemplated the capacity of the current system to meet future demand.

For most focus group participants, roads and public transportation were seen as particularly pressing infrastructure issues, especially for residents of sub-urban areas. Upon further discussion, it became clear that these issues capture more public attention because they are "felt" or "seen" on a daily basis. There was also a sense that the transportation network is in a serious state of disrepair and simply can't handle the volume of traffic. Moreover, it was a commonly held view among participants that Toronto's transit infrastructure is not "world-class" and does not adequately meet the needs of a city of its size.

"*This is the only big city in the world where you cannot get to the airport on the subway. In Hong Kong, you can get to the airport by subway and the airport is an island. This city was not designed to be this big.*"

Participants also tended to focus, top of mind, on issues that had either a direct environmental impact or which affected their views of the degree to which their communities incorporated environmental elements, such as green spaces and park areas as well as garbage collection. In addition, participants were preoccupied with the quality of water and sewage treatment systems, expressing concern about the health effects. Based on comments from the focus groups and given the relative rankings of infrastructure priorities in the survey, those priorities that tend to garner moderate to higher levels of concern exhibit the following features:

- Those that are most visible to residents (roads, highways);
- Those that are "felt" or experienced on a relatively frequent basis (i.e. roads, highways, public transit);
- Those that could have a significant adverse impact with respect to inconveniencing residents when there are issues regarding their functioning (i.e. public transit, roads, highways, electricity distribution system); and
- Those that are perceived to have associated environmental, health or safety risks if they are not functioning effectively and efficiently (i.e. sewage and wastewater treatment system, water distribution system, electricity distribution).

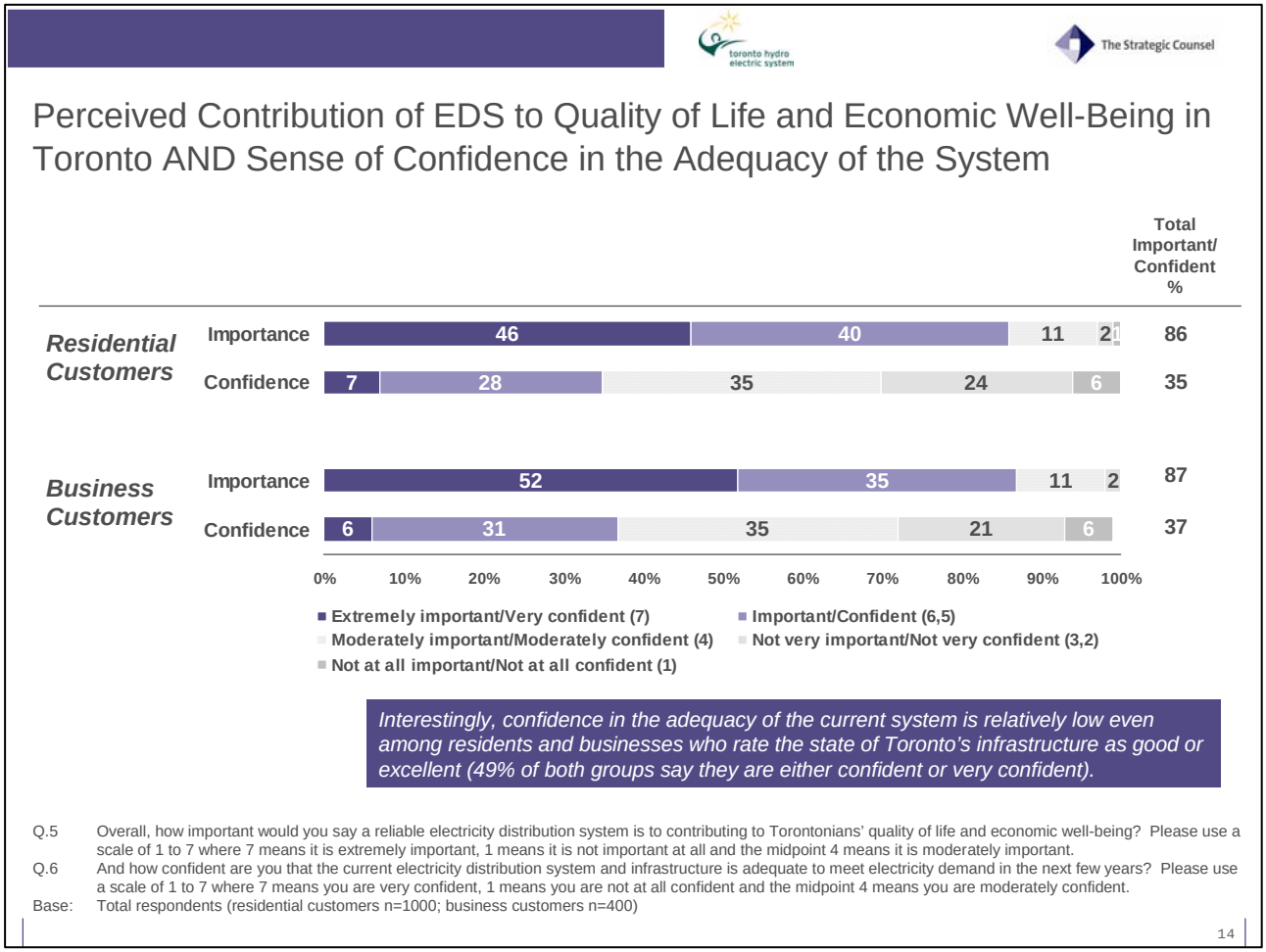
D. Perceived Contribution of the Electricity Distribution System to Torontonians' Quality of Life

Responses to the survey revealed that customers place a high degree of importance on a reliable electricity distribution system as a key contributor to Torontonians' quality of life and economic well-being. On a 7-point scale, where 1 means it is not important at all, 7 means it is extremely important and the mid-point 4 means it is moderately important, just under half of residential customers (46%) and just over half of small business customers (52%) assessed the highest rating of 7 "extremely important." When "topbox" scores are combined (i.e. those that offered a rating of 5, 6 or 7), 86 per cent of residential customers and 87 per

cent of small business customers indicated that a reliable EDS was important to Toronto's quality of life and economic prosperity (Chart 6).

Notably, however, substantially fewer among these customer groups expressed confidence that the current electricity distribution system and infrastructure is adequate to meet electricity demand in the next few years. Fewer than one-in-ten in each customer segment (7% of residential customers; 6% of small business customers) said they were "very confident." Indeed, fewer than four-in-ten in each customer segment (35% of residential customers; 37% of small business customers) expressed any degree of confidence in the current EDS. Of note, confidence in the adequacy of the current EDS to meet future electricity demand over the next few years is low even among those respondents who rated the state of Toronto's infrastructure as either "good" or "excellent." Even among this group, under half (49%) said they were either "very confident" or "confident" (i.e. a 5, 6 or 7 on a 7-point scale).

Chart 6: Contribution of EDS to Quality of Life/Economic Well-Being and Confidence in the System – Telephone Survey



In the focus groups, when asked more directly about the relative importance of the EDS as an infrastructure priority and its contribution to Torontonians' quality of life, participants responded with a somewhat greater sense of urgency about the issue than they had in the earlier more general discussion of infrastructure priorities. Participants' comments suggest that the issue is one that could ignite strong concern fairly quickly with relatively little discussion.

"We take it for granted, but can't live without it."

"The ripple effect is unbelievable."

"It would throw us back into the 19th century [if the system wasn't functioning adequately]."

The difference in views between those residing in areas affected by more frequent power outages and others was quite striking, as expressed by the following comments from several participants in the group comprised of customers residing in North York:

"Where I live, the power goes out for a few seconds to a few minutes a couple of times every month. East York is famous for it."

"The same for me. We have flashlights and candles all over the house. If it rains heavily [the power goes out] from five minutes to a few hours. Something is wrong with the system. They should do something."

"Where are those outages coming from? A little rain and no electricity. It is like a third world country."

"I spent the first 30 years of my life in the former Yugoslavia. We never had the number of power disruptions that I experience here. The difference here is that the lines run through the trees, whereas there they are underground. The huge black-out we had a few years ago … I cannot recall something like that ever happening in Europe."

Given most focus group participants' relatively limited knowledge of the electricity sector and of the various players and elements that comprise the system, when asked to comment on the current state of the EDS, many focused immediately in issues pertaining to the generation and overall supply of electricity. Participants' concerns were principally centered on issues of capacity as well as the environmental impacts of current electricity generation technologies and energy sources rather than on the power poles, substations and transformers or the "wires" part of the grid.

"It's in a pretty precarious state … They are running close to capacity and from what I hear, they haven't done anything to fix this."

"We do purchase a lot from our neighbours east, west and south so we are not self-sufficient."

"Terribly inefficient, a lot of dirty energy … old."

"I am concerned about the lack of search for alternative energy sources."

"We still do not have clean energy generation."

In line with what Toronto Hydro has heard in other focus group research with customers, electricity can be classified as a "low involvement" category unless and until the lights go out. As one participant noted, "we do not have outages, so it works."

Participants admitted a low level of knowledge about the state of the EDS, although they expressed a strong interest in knowing more. They questioned why they had not heard any public discussion on the state of the

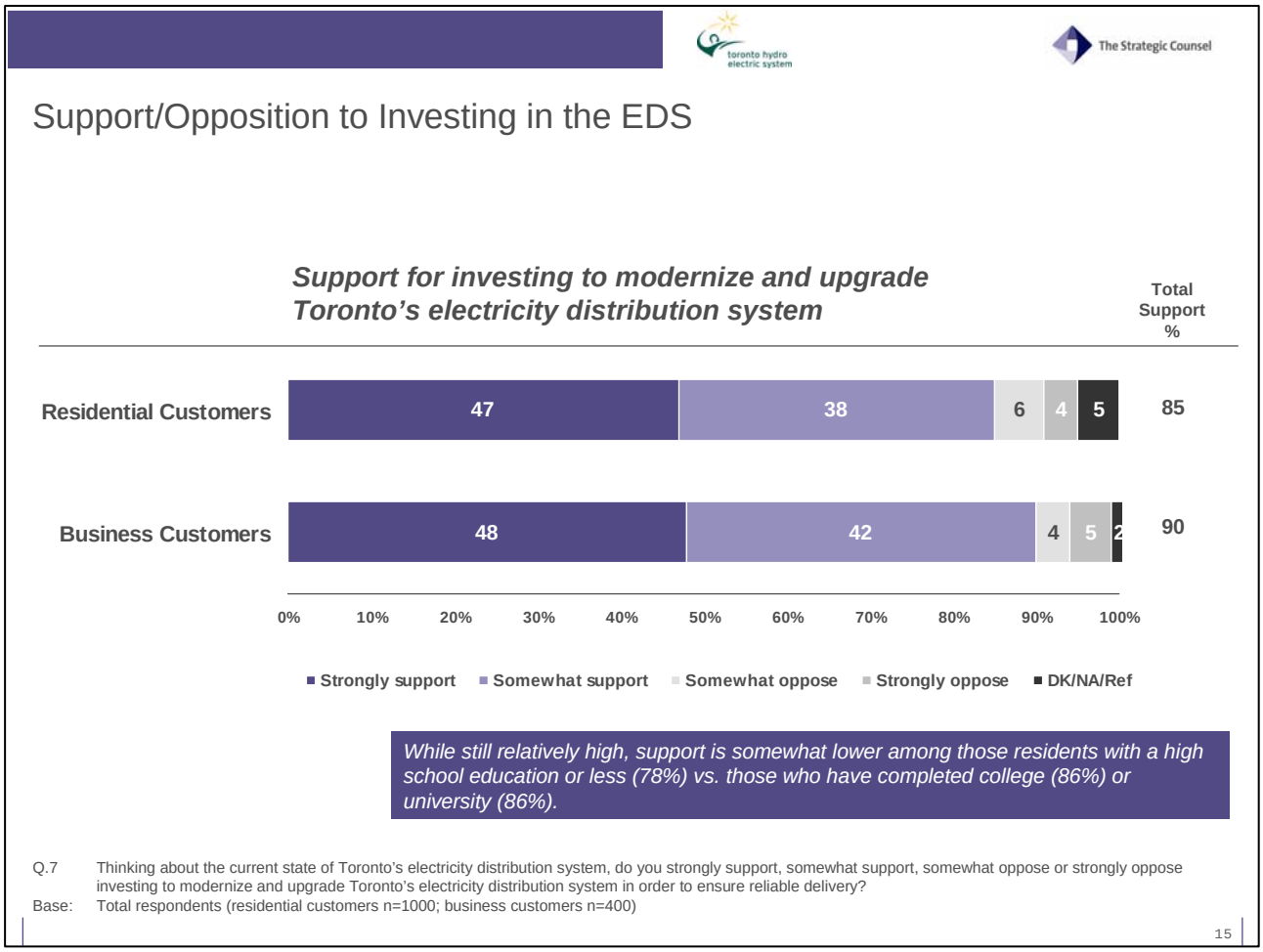
EDS and the need for investments, particularly among their municipal councillors. Given this, some participants were reluctant to endorse significant investments.

Among participants to the groups, there was a strong concern about a lack of planning on the part of governments of all levels to address the infrastructure needs of cities like Toronto that are growing much faster than expected. This sense is exacerbated by an expressed view among participants that the demand for electricity will continue to rise as residents and businesses incorporate additional technologies powered by electricity into their daily home and work lives. Moreover, participants felt that more frequent extreme weather events (i.e. summer heat waves) would place additional pressure on the grid and the EDS.

E. Support for Modernizing and Upgrading Toronto's Electricity Distribution System

The vast majority of residential (85%) and small business (90%) customers support investing to modernize and upgrade Toronto's electricity distribution system in order to ensure reliable delivery (Chart 7). In fact, just under half of customers "strongly support" additional investments in upgrading the EDS (47% of residential customers; 48% of small business customers).

Chart 7: Support/Opposition to Investing in the EDS – Telephone Survey



There are no significant variations in support for further investments to modernize the EDS by area within Toronto.

The most important reason for investing in the city's electricity distribution, for both residential and small business customers, is to meet anticipated growth. Four-in-five (80%) of both residential and small business customers segments (Charts 8a and 8b respectively) agreed that "given the City's anticipated population growth, new buildings and increased technology use, I think the City's electricity distribution system will require further investments to keep pace."

Customers, especially residential customers, also expressed moderate levels of concern about future brown-outs and black-outs (72% of residential customers agreed they will occur more frequently in the future; 57% of small business customers).

While just over half (54%) of residential customers agreed that "in many parts of Toronto, the electricity distribution system is old and in need of repair," this number jumped to two-thirds (66%) among customers residing in "problem areas." In general, small business customers (62%) were more inclined that residential customers overall to agree that the system is aging and needs repair.

At the same time, a significant number of customers (60% of residential; 53% of small business) agreed that "there are more important infrastructure priorities than investing to modernize Toronto's electricity distribution system."

Chart 8a: More Views on the Need for Repairs to the EDS: Residential Customers – Telephone Survey

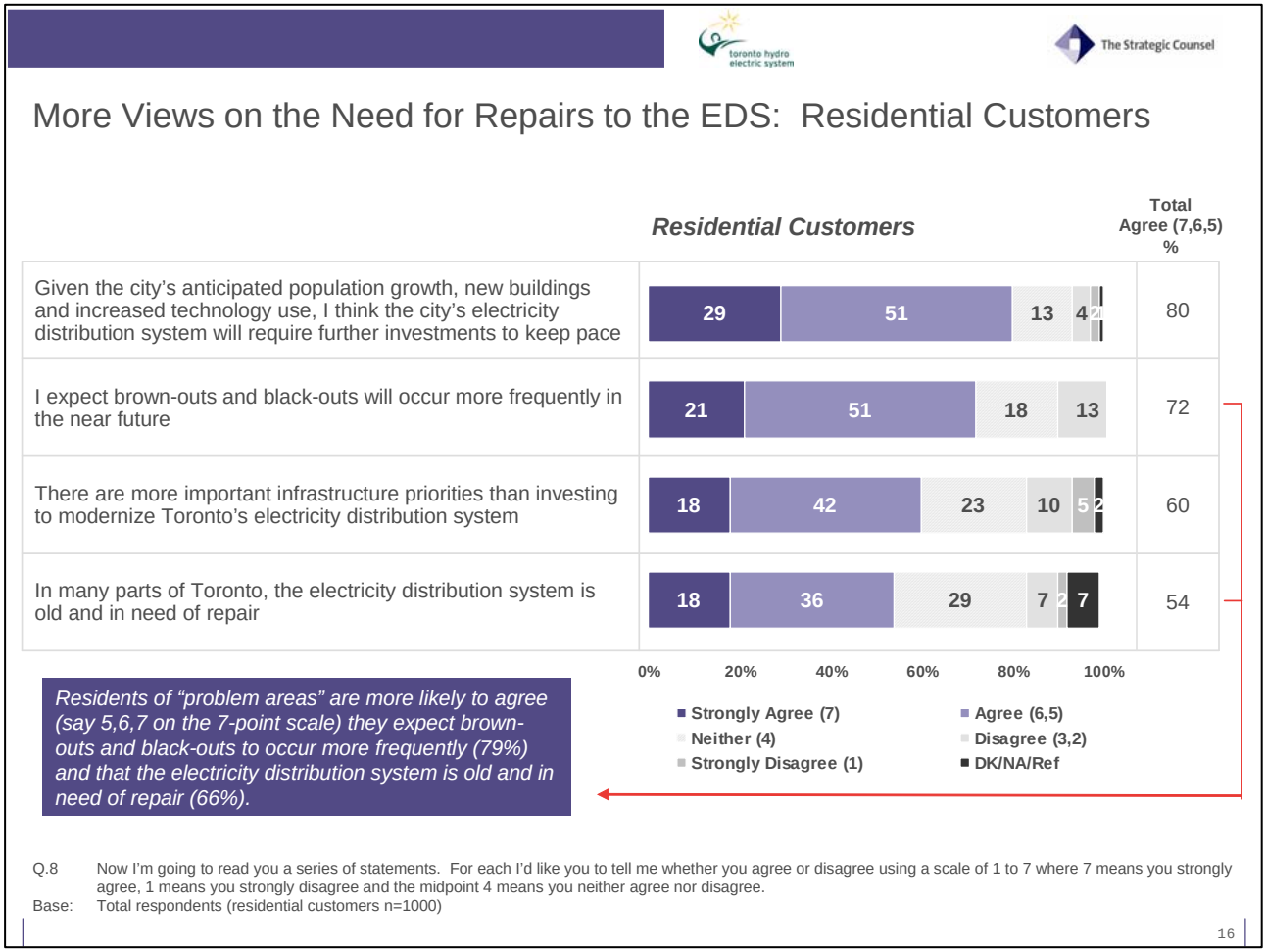
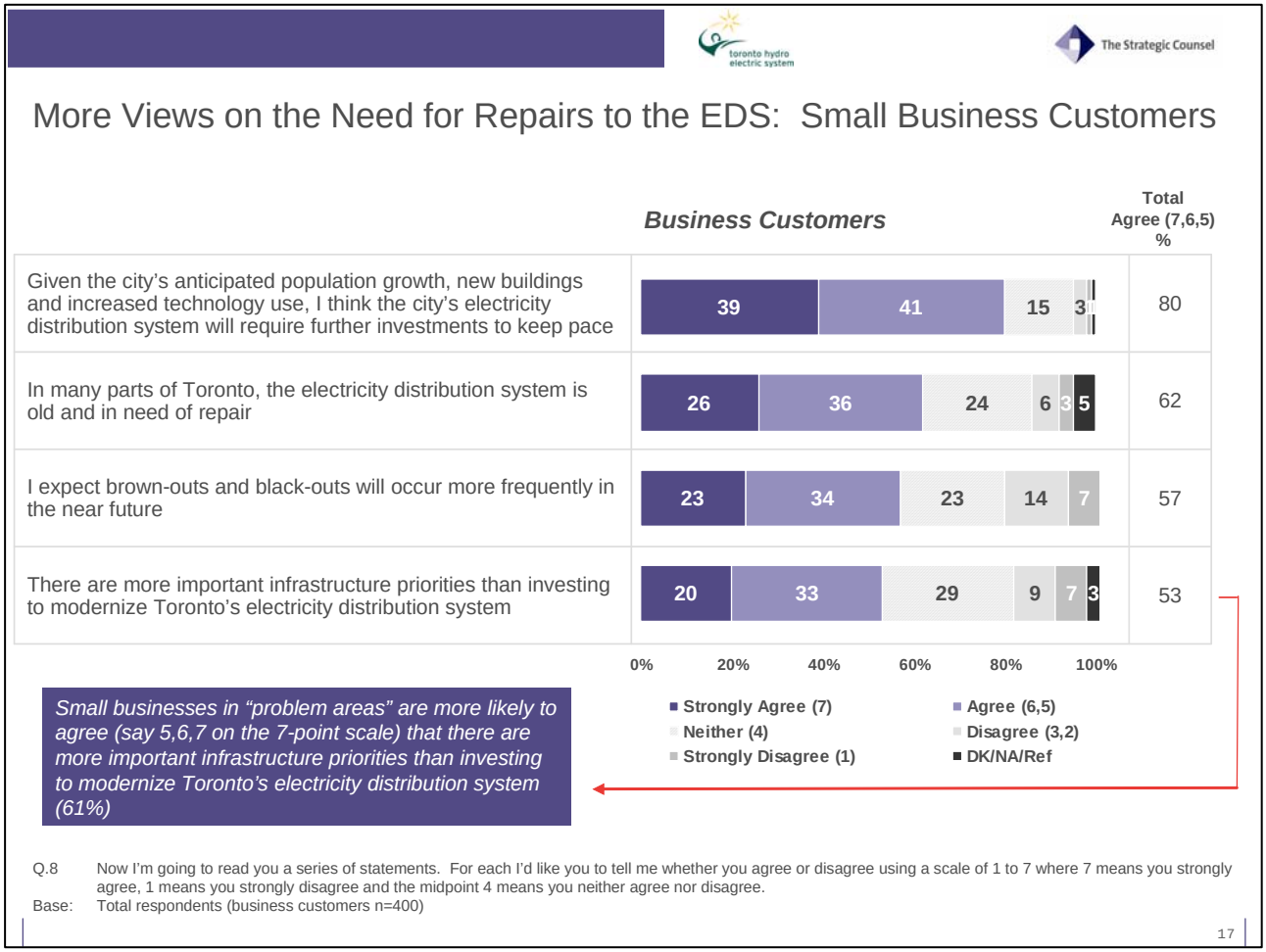


Chart 8b: More Views on the Need for Repairs to the EDS: Small Business Customers – Telephone Survey



In focus groups, few participants could identify specifically what kinds of upgrades might be necessary, although they generally supported investing in the EDS to maintain and upgrade the system. Participants' first thoughts turned to burying wires that are now currently above ground and replacing aging poles. Notably, many participants via their comments seemed to suggest that they were operating under an assumption that Toronto Hydro had been regularly maintaining the system. As such, they are somewhat surprised (and concerned) to discover that much of the system has past its expected lifespan. At the same time, they were concerned about ensuring maintenance and upgrades are well-considered, thoughtfully planned and undertaken with a view to transparency and accountability in terms of public monies invested.

> *"If you look at the transmission lines, they have probably been there for 50 years. Are they close to breaking down? I do not know. I assume Hydro spends money replacing certain things."*

"I think it is urgent, but I would not want them to rush into something before it is properly researched. I am amazed that it has worked as well as it has."

Focus group participants expressed little surprise when told that 35 per cent of Toronto's electricity distribution has past its expected lifespan. Almost as many thought this number sounded reasonable as thought it was perhaps somewhat low. Nevertheless, the introduction of this fact generated some debate in group discussions as to why Toronto Hydro appears to have fallen so far behind in maintaining the system in good working order.

"Shouldn't they replace things before they go?"

"Why is that? Is it a lack of planning or are they deciding to use things until they completely fall apart?

"If you were a for profit corporation and 35% of your resources/tools were past their date, you would be freaking out."

"You cannot wait to find out that 70 per cent has to be replaced. There should be a continuous upgrading."

F. Perceptions of Costs versus Benefits

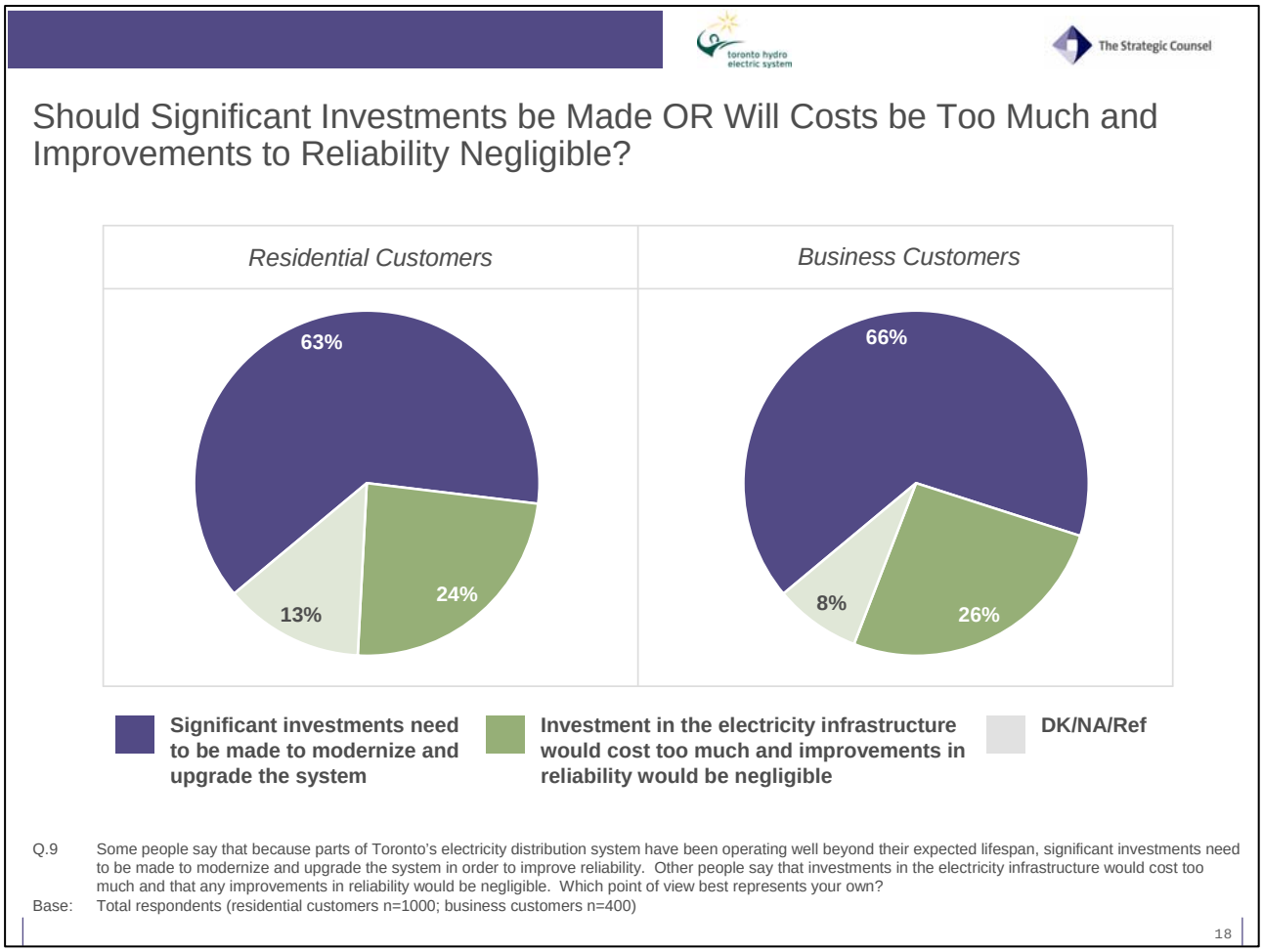
Customers, although somewhat conflicted over the issue of what they perceived to be rising electricity costs (and which they feel will likely continue to rise), are generally supportive of significant investments in the electricity distribution system. Indeed, in focus groups, participants expressed an expectation that upgrades would reduce overall costs to consumers, or at least dampen upward pressure on electricity costs.

"Well the system will be more efficient and if it is more efficient, it will be less costly so hopefully the price will drop … ok, maybe not go down but go up more slowly."

Just over six-in-ten respondents to the survey (63% of residential customers; 66% of small business customers) held the view that significant investments need to be made to modernize and upgrade the system in order to improve reliability (Chart 9). By contrast, about one-quarter in each customer segment (24% of residential customers; 26% of small business customers) felt that investments in the electricity infrastructure would cost too much and that any improvements in reliability would be negligible.

Again, there were no significant variations in responses to this question by area.

Chart 9: Support for Significant Investments versus Concern over Costs – Telephone Survey



Participants in the focus groups expressed concerns about possible cost overruns, given their impressions of the experience of other major municipal infrastructure projects.

"How are they going to manage the money/costs? Are they going to say that it cost 1 billion dollars and then you hear on the news that it was 15 billion dollars?"

The Strategic Counsel

Appendix A: Survey Questionnaires

The Strategic Counsel

Reliability/Capital Spending
Toronto Hydro Electricity System
Survey of Residential Customers

Hello, I am calling from *The Strategic Counsel*, a professional market research firm. Today we are conducting a survey on some important issues affecting residents and businesses in the Toronto area. Could I speak with the person in your household who is 18 years of age or older and who pays your hydro bills? (ONCE APPROPRIATE RESPONDENT HAS BEEN IDENTIFIED, RESTART OR CONTINUE …) The survey will take no more than 5 to 7 minutes of your time. All your responses are confidential. May I continue?

1. First, as a resident of/business located in the Greater Toronto Area what are the most important issues for you, that is those issues that you feel the municipal and provincial governments should focus on most? Anything else? (UP TO THREE RESPONSES)

2. In general, how would you rate the state of Toronto's infrastructure, infrastructure being roads, transit, water, sewers and the electricity distribution system? Would you say that in general it is in excellent, good, fair, poor or very poor condition?

   - Very poor
   - Poor
   - Fair
   - Good
   - Excellent

3. And, based on what you know or your impressions, how would you compare the state of repair of Toronto's infrastructure with that of other major cities in Canada? Would you say it is much better than, better than, about the same as, worse than or much worse than other cities in Canada?

   - Much worse
   - Worse
   - About the same
   - Better
   - Much better

4. Thinking about various components of Toronto's infrastructure, please tell me what level of priority you would place on improving each of the following. You can do this by using a scale of 1 to 7, where 7 is a "high priority," 1 is a "low priority" and the midpoint, 4, means a "moderate" priority. What about … (READ AND ROTATE)

   a. The sewage and wastewater treatment system
   b. The electricity distribution system, being the wires that bring electricity to homes and businesses
   c. The public transit system, including buses and the subway
   d. The water distribution system
   e. The natural gas distribution system
   f. Roads, highways and bridges
   g. Broadband Internet communications infrastructure, for example, WIFI

5. Overall, how important would you say a reliable electricity distribution system is to contributing to Torontonians' quality of life and economic well-being? Please use a scale of 1 to 7 where 7 means it is "extremely important," 1 means it is "not important at all," and the mid-point, 4, means it is "moderately important."

6. And, how confident are you that the current electricity distribution system and infrastructure is adequate to meet electricity demand in the next few years? Please use a scale of 1 to 7, where 7 means you are "very confident," 1 means you are "not at all confident" and the mid-point "4" means you are "moderately confident."

7. Thinking about the current state of Toronto's electricity distribution system, do you strongly support, somewhat support, somewhat oppose or strongly oppose investing to modernize and upgrade Toronto's electricity distribution system in order to ensure reliable delivery?

   - Strongly oppose
   - Somewhat oppose
   - Somewhat support
   - Strongly support

8. Now, I'm going to read you a series of statements. For each, I'd like you to tell me whether you agree or disagree using a scale of 1 to 7, where 7 means "strongly agree," 1 means you "strongly disagree," and the mid-point 4 means you "neither agree nor disagree." The first one is … (READ AND ROTATE)

   a. I expect brown-outs and black-outs will occur more frequently in the near future as a result of increased demand on the city's electricity distribution system.
   b. In many parts of Toronto, the electricity distribution system is old and in need of repair.
   c. There are more important infrastructure priorities than investing to modernize Toronto's electricity distribution system.
   d. Given the city's anticipated population growth, new buildings and increased technology use, I think the city's electricity distribution system will require further investments to keep pace.

   RANDOMIZE STATEMENTS

9. Some people say that because parts of Toronto's electricity distribution system have been operating well beyond their expected lifespan, significant investments need to be made to modernize and upgrade the system in order to improve reliability.

Other people say that investments in the electricity infrastructure would cost too much and that any improvements in reliability would be negligible. Which point of view best represents your own?

- Significant investments need to be made
- Investments would be too costly

886: **D1**

RECORD YEAR - XXXX

Finally, I would like to ask some questions for statistical purposes. I'd like to remind you that all your answers are completely confidential. D1. In what year were you born?

$E 1900 1988

Don't Know/Refused 9999

887: **D2**

READ LIST.

D2. What is the highest level of formal education that you have completed?

Grade 8 or less 1
Some high school 2
Complete high school 3
Technical, vocational post-secondary, college 4
Some university 5
Complete university degree 6
Post graduate degree 7
DO NOT READ - Refused 9

151: **D10**

D10. Which of the following best describes your living situation?

Own 01
Rent 02
Living with parents/relatives 03
Other 88
DK/NR .....99 X

895: **D10**

READ LIST.

Which of the following categories best describes your total household income? That is, the total income of all persons in your household combined, before taxes?

Under $10,000 01
$10,000 to $ 19,999 02
$20,000 to $29,999 03
$30,000 to $39,999 04
$40,000 to $49,999 05
$50,000 to $59,999 06
$60,000 to $69,999 07
$70,000 to $79,999 08
$80,000 to $99,999 09
$100,000 and over 10
DO NOT READ - Refused 99

The Strategic Counsel

Reliability/Capital Spending
Toronto Hydro Electricity System
Survey of Small Business Customers

Hello, I am calling from *The Strategic Counsel*, a professional market research firm. Today we are conducting a survey on some important issues affecting residents and businesses in the Toronto area. Could I speak with the manager? (ONCE APPROPRIATE RESPONDENT HAS BEEN IDENTIFIED, RESTART OR CONTINUE …) The survey will take no more than 5 to 7 minutes of your time. All your responses are confidential. May I continue?

1. First, as a resident of/business located in the Greater Toronto Area what are the most important issues for you, that is those issues that you feel the municipal and provincial governments should focus on most? Anything else? (UP TO THREE RESPONSES)

2. In general, how would you rate the state of Toronto's infrastructure, infrastructure being roads, transit, water, sewers and the electricity distribution system? Would you say that in general it is in excellent, good, fair, poor or very poor condition?

- Very poor
- Poor
- Fair
- Good
- Excellent

3. And, based on what you know or your impressions, how would you compare the state of repair of Toronto's infrastructure with that of other major cities in Canada? Would you say it is much better than, better than, about the same as, worse than or much worse than other cities in Canada?

- Much worse
- Worse
- About the same
- Better
- Much better

4. Thinking about various components of Toronto's infrastructure, please tell me what level of priority you would place on improving each of the following. You can do this by using a scale of 1 to 7, where 7 is a "high priority," 1 is a "low priority" and the midpoint, 4, means a "moderate" priority. What about … (READ AND ROTATE)

a. The sewage and wastewater treatment system
b. The electricity distribution system, being the wires that bring electricity to homes and businesses
c. The public transit system, including buses and the subway
d. The water distribution system
e. The natural gas distribution system
f. Roads, highways and bridges
g. Broadband Internet communications infrastructure, for example, WIFI

5. Overall, how important would you say a reliable electricity distribution system is to contributing to Torontonians' quality of life and economic well-being? Please use a scale of 1 to 7 where 7 means it is "extremely important," 1 means it is "not important at all," and the mid-point, 4, means it is "moderately important."

6. And, how confident are you that the current electricity distribution system and infrastructure is adequate to meet electricity demand in the next few years? Please use a scale of 1 to 7, where 7 means you are "very confident," 1 means you are "not at all confident" and the mid-point "4" means you are "moderately confident."

7. Thinking about the current state of Toronto's electricity distribution system, do you strongly support, somewhat support, somewhat oppose or strongly oppose investing to modernize and upgrade Toronto's electricity distribution system in order to ensure reliable delivery?

- Strongly oppose
- Somewhat oppose
- Somewhat support
- Strongly support

8. Now, I'm going to read you a series of statements. For each, I'd like you to tell me whether you agree or disagree using a scale of 1 to 7, where 7 means "strongly agree," 1 means you "strongly disagree," and the mid-point 4 means you "neither agree nor disagree." The first one is … (READ AND ROTATE)

a. I expect brown-outs and black-outs will occur more frequently in the near future as a result of increased demand on the city's electricity distribution system.
b. In many parts of Toronto, the electricity distribution system is old and in need of repair.
c. There are more important infrastructure priorities than investing to modernize Toronto's electricity distribution system.
d. Given the city's anticipated population growth, new buildings and increased technology use, I think the city's electricity distribution system will require further investments to keep pace.

RANDOMIZE STATEMENTS

9. Some people say that because parts of Toronto's electricity distribution system have been operating well beyond their expected lifespan, significant investments need to be made to modernize and upgrade the system in order to improve reliability.

Other people say that investments in the electricity infrastructure would cost too much and that any improvements in reliability would be negligible. Which point of view best represents your own?

- Significant investments need to be made
- Investments would be too costly

The next few questions are for statistical purposes only …

Q10.Gender (DO NOT READ)
Male
Female

Q11. Please estimate the number of employees in your firm. **READ LIST. RECORD ONE ONLY.**

- 1-50
- 51-250
- 251 or more

Q12. What is your job title?

Q13. And what sector would you say your business is in?
Retail 1
Transportation 2
Manufacturing 3
Professional Services..... 4
Other (DO NOT READ!!)..... 7
Property Management/Real Estate 5
Service/Food Service..... 6
Non-Profit/Religious 8
Don't Know/Refusal 9
Education.....A
Hospitality .....B

That's all the questions I have for you. Thank you for participating in this study. Have a great day.

Appendix B: Call Dispositions

The Strategic Counsel

Record Of Contact

Project Name:	Toronto Hydro Residential	**Call Centre(s)** ☑
Project Number:		**Ottawa** ☐
Field Start Date:	Thursday, March 29, 2007	☐
Field End Date:	Tuesday, April 10, 2007	

	Total #	%
Total Completes	**1,000**	**5.23%**

A. Total Numbers Attempted

Total Call Records	23,476	
Total Unallocated		
Quota Full - No Dial	4,355	
Total Numbers Attempted (Net Potential Sample)	**19,121**	

Ineligible Numbers

Number Changes / NIS	2,501	**13.08%**
Business / Fax / Cell Phone / Computer	2,936	15.35%
Phone Number Problem	66	0.35%
Call Blocked	47	0.25%
Quota Full	1,098	5.74%
Duplicate Numbers	1	0.01%
Total Invalid Numbers	*6,649*	*34.77%*
B. Total Eligible Numbers *(Net Potential Sample - Total Invalid #s)*	**12,472**	**65.23%**

C. Total Asked

Call Back:	Hard Appointments	208	1.09%
	Soft Appointments	863	4.51%
Partial Complete		8	0.04%
Not Available Until After Survey		58	0.30%
No Answer		1,396	7.30%
Answering Machine		2,604	13.62%
Busy		67	0.35%
Language Problem: French		34	0.18%
Language Problem: Other		948	4.96%
Respondent Not Available		34	0.18%
Other Problem		74	0.39%

Didn't Dial	31	0.16%
Total Unreachable	*6,325*	*33.08%*
Total Asked (Total Eligible Numbers - Total Unreachable)	**6,147**	**32.15%**

Refusals

Upfront	4,698	24.57%
2nd Refusals	13	0.07%
Do not call list	181	0.95%
Eligible Respondent Refusal	113	0.59%
Middle Refusal	86	0.45%
Total Refusals	*5,091*	*26.63%*

D. Cooperative Contacts (Total Asked - Refusals)	1,056	
Not Household Member	1	0.01%
No such person	55	0.29%
No Call Status		
Completed Interviews	1,000	5.23%
Total Cooperative Contacts	**1,056**	**5.52%**

The Strategic Counsel

Record Of Contact

Project Name:	Toronto Hydro B2B	**Call Centre(s)** ☑
Project Number:		**Ottawa** ☐
Field Start Date:	Monday, April 02, 2007	☐
Field End Date:	Monday, April 09, 2007	

	Total #	%
Total Completes	**400**	**6.70%**

A. Total Numbers Attempted

Total Call Records	8,242	
Total Unallocated		
Quota Full - No Dial	2,271	
Total Numbers Attempted (Net Potential Sample)	**5,971**	

Ineligible Numbers

Number Changes / NIS	451	**7.55%**
Business / Fax / Cell Phone / Computer	536	8.98%
Phone Number Problem	65	1.09%
Call Blocked	7	0.12%
Quota Full	1	0.02%
Duplicate Numbers	11	0.18%
Total Invalid Numbers	*1,071*	*17.94%*
B. Total Eligible Numbers *(Net Potential Sample - Total Invalid #s)*	**4,900**	**82.06%**

C. Total Asked

Call Back:	Hard Appointments	158	2.65%
	Soft Appointments	1,203	20.15%
Partial Complete		4	0.07%
Not Available Until After Survey		77	1.29%
No Answer		314	5.26%
Answering Machine		576	9.65%
Busy		15	0.25%
Language Problem: French		1	0.02%
Language Problem: Other		206	3.45%
Respondent Not Available		331	5.54%
Other Problem		125	2.09%

Didn't Dial	0	0.00%
Total Unreachable	*3,010*	*50.41%*
Total Asked (Total Eligible Numbers - Total Unreachable)	**1,890**	**31.65%**

Refusals

Upfront	959	16.06%
2nd Refusals	4	0.07%
Do not call list	28	0.47%
Eligible Respondent Refusal	306	5.12%
Middle Refusal	28	0.47%
Total Refusals	*1,325*	*22.19%*

D. Cooperative Contacts (Total Asked - Refusals)	565	
Disqualified 1	1	0.02%
No such person	164	2.75%
No Call Status		
Completed Interviews	400	6.70%
Total Cooperative Contacts	**565**	**9.46%**

The Strategic Counsel

Appendix C: Focus Group Recruiting Script

The Strategic Counsel

Toronto Hydro

Residential Customers Reliability Study

Focus Group Recruiting Script

May 2007

Hello, my name is _____ and I'm calling from *The Strategic Counsel*, a national market research company. As part of the market research that we conduct, we often hold discussion groups where several people get together to talk about their opinions on a variety of topics.

We are conducting one of these groups in the next couple of weeks and I wanted to know if you are interested in participating. You would be paid $75 for your attendance but I want to assure you, we are not selling anything. Your input at this discussion group would provide us with information about your feelings on issues related to the distribution of electricity in and around the Greater Toronto Area. Your views will be kept completely confidential and no identifiable comments will be included in our reporting of the issue being discussed. If you are interested in participating, I will need to verify your eligibility by asking you a few questions.

1. First, do you or does anyone in your household work in... (READ LIST)?

A market research company or market research department in a company	**THANK AND TERMINATE**
A Marketing firm	**THANK AND TERMINATE**
An advertising or public relations company	**THANK AND TERMINATE**
A private or public company that is involved in electricity distribution in Ontario	**THANK AND TERMINATE**
Any media such as television, radio or a newspaper or magazine	**THANK AND TERMINATE**
A public relations company	**THANK AND TERMINATE**

2. Do you currently rent or own your home?

❑[1]	Rent	**Thank and terminate**
❑[2]	Own	**Continue**
❑[3]	Other/Not sure/DK	**Thank and terminate**

3. Are you normally the person who takes care of paying the electricity bill in your household?

❑[1]	Yes	**Continue to Q.5**
❑[2]	No	**Ask Q.4**
❑[3]	Other/Not sure/DK	**Thank and terminate**

4. And, are you typically the person, or one of the persons, who would phone your electricity provider in case of electrical problems at home?

❑[1]	Yes	**Continue**
❑[2]	No	**Thank and terminate**
❑[3]	Other/Not sure/DK	**Thank and terminate**

5. Would you describe yourself as ….

❑1	Working full-time	**Continue**
❑2	Working part-time	**Continue**
❑3	Unemployed and looking for work	**Accept only limited amount**
❑4	Unemployed and not looking for work	**Accept only limited amount**
❑5	Retired	**Accept only limited amount**
❑3	A homemaker	**Accept only limited amount**
❑4	A student	**Accept only limited amount**
❑5	Other	**Accept only limited amount**

IF EMPLOYED FULL-TIME OR PART-TIME AT Q.6, ASK Q.7. OTHERWISE, SKIP TO Q.8.

7. What is your occupation?

_____

GET A GOOD MIX OF OCCUPATIONS

6. It is important that we get a mix of people of different ages in the group. In which of the following age groups do you belong?

❑1	Less than 18	**THANK AND TERMINATE**
❑2	18-24	**Continue**
❑3	25-34	**Continue**
❑4	35-44	**Continue**
❑5	45-54	**Continue**
❑6	55-64	**Continue**
❑7	65 and older	**Continue**

GET A GOOD MIX OF AGES

8 My friends would say I'm very comfortable expressing my opinions in a group.

❑1	Describes	**Continue**
❑2	Does not describe	**THANK AND TERMINATE**

9. I tend to be kind of person who enjoys talking about important issues with other people.

❑1	Describes	**Continue**
❑2	Does not describe	**THANK AND TERMINATE**

10. Have you attended a discussion group in the past? (**IF YES, ASK:** How long ago was that)

❑1	Less than 1 year ago	**THANK AND TERMINATE**
❑2	More than 1 year ago	**Continue**
❑3	Don't remember	**THANK AND TERMINATE**

11. And what was the topic of the group or groups you have attended?

_____

If about electricity distribution issues, thank and end interview

12. It is important to get a range of income levels for the focus groups. Which of the following best describes your household income?

❑1	Under $25,000	**Continue**
❑2	$25,000 - $39,999	**Continue**
❑3	$40,000 - $59,999	**Continue**
❑4	$60,000 - $79,999	**Continue**
❑5	$80,000 - $99,999	**Continue**
❑6	$100,000 - $149,999	**Continue**
❑7	$150,000+	**Continue**

GET A GOOD MIX OF HOUSEHOLD INCOME

13. Gender **(DO NOT ASK)**

❑1	Male
❑2	Female

GET A GOOD MIX OF GENDER

ENSURE THOSE THAT NEED READING GLASSES BRING THEM.

I would like to invite you to a focus group discussion about a topic that is relevant to Canadians today. In appreciation for your attendance, you will receive ($75). The discussion will last about two hours and will be held at:

(**Specify location, date and time of group**)

We will be calling to verify the information given and will confirm this appointment the day or evening before.

If you don't hear from us, your appointment to attend the discussion is not confirmed and you will not be allowed into the group. If we have been unable to contact you, please telephone us at (416) _____

We request that you arrive five to ten minutes prior to the discussion so that we can begin on schedule. Thank you.

The Strategic Counsel

Appendix D: Focus Group Moderator's Guide

The Strategic Counsel

Toronto Hydro
Reliability Focus Groups
Moderator's Guide
May 16, 2007

Introduction (5 minutes)

- Introduce moderator and purpose of groups
  - Discuss issues related to infrastructure improvements in your community
- Review group procedures
  - No right or wrong answers
  - Important to hear from everyone
  - Will move through topics/exercises fairly quickly. May have to cut discussion short to ensure we cover all topics.
  - Few rules or restrictions except that only one speaker at a time
  - Groups are being audio and video-taped in order to allow for review at the time of analysis
  - Groups are also being observed by TSC and TH employees
- Participant introductions
  - i. Ask participants to introduce themselves, first name only.
  - ii. Ask participants to state the area/community in which they reside

Warm-Up/Context – Infrastructure: Perceived state of and key priorities (25 minutes)

- Over the next two hours I'd like to get your views on the state of infrastructure in your community and your priorities for infrastructure improvements. To begin, I would like to understand what kinds of things you feel are encompassed by the term infrastructure. What does that term mean to you?
  - What aspects or features of a community do you consider to be part of its infrastructure? (MODERATOR TO LIST ON FLIP CHART)
- And, taking all these things together, in general, how would you rate the current state of infrastructure in the City of Toronto? Would you say it is in excellent, good, fair, poor or very poor condition? Explain.
  - If "fair/poor/very poor" – In your view, what accounts for this? Probe for:
    - Not a priority
    - Poor planning/decision-making
    - Inadequate funding
      - And, who would you say is mostly responsible for funding infrastructure improvements?
- Now, I'd like each of you to take a pencil and paper and write down your top five infrastructure priorities – that is, the issues that you believe should be addressed either in your own neighborhood/community or more broadly across the City of Toronto. (ROUND TABLE REVIEW OF PRIORITIES. MODERATOR TO LIST ON FLIP CHART.)
- Now, I'd like to take a moment and attempt to categorize these priorities into groups according to whether you view these as high, moderate or lower level priorities. Which of these priorities on the flip chart would you say are high priorities? Which are moderate priorities and which are lower priorities, relatively speaking? MODERATOR TO CONDUCT EXERCISE AMONG LARGE GROUP ON FLIP CHART. IT IS LIKELY THAT THERE WILL BE SOME DISAGREEMENT AMONG PARTICIPANTS ON PRIORITY STATUS/RATING … MODERATOR TO ALLOW FOR VARYING POINTS OF VIEW AND TO NOTE DIFFERENCES.
  - In your view, what is the critical difference between high, moderate and low priorities? Probe for:
    - Number of residents affected

- Relative impact on local economy
- Relative impact on quality of life
- Relative state of disrepair

Electricity Distribution System – Relative positioning among other infrastructure priorities (25 minutes)

- LEAD IN TO THIS SECTION WILL DEPEND ON WHETHER ELECTRICITY DISTRIBUTION SYSTEM IS RAISED AS A HIGH/MODERATE/LOW PRIORITY IN PREVIOUS SECTION. MODERATOR TO ADJUST DISCUSSION AS NECESSARY.
- I'd like to focus on the state of the electricity distribution system in your community. When you consider the other priorities listed on the flip chart, where does the electricity distribution system fall among these other infrastructure improvements? Probe for:
  - Is it a higher/moderate/lower level priority? Why do you say this?
  - Overall, how important would you say a reliable electricity distribution system is to contributing to Torontonians' quality of life and economic well-being? Please explain. How does it/would it impact your quality of life? In what specific ways?
- Overall, how would you rate the current state of the electricity distribution system in your neighborhood/across the City of Toronto? Would you say it is in excellent, good, fair, poor or very poor condition? Why?
  - For those saying "fair/poor/very poor" – what specifically is the issue?
  - And, how are you personally affected by this?
- How would you rate the state of the electricity distribution system in your community/area compared to other parts of Toronto? Is it better/same/worse? Why do you say that?
- Whose responsibility would you say it is to address this issue? Probe for:
  - City of Toronto
  - Ontario Government
  - Toronto Hydro
  - Combination of the above

Sense of urgency attached to upgrading the electricity distribution system (20 minutes)

- And, in the scheme of things, how urgent do you feel it is to modernize your community's/Toronto's electricity distribution system? Probe for:
  - Would you describe it as extremely urgent, somewhat urgent, not too urgent, or not urgent at all? Explain.
  - How does this compare with other infrastructure priorities with respect to urgency?
- What are the main reasons why the system should be upgraded? Probe for:
  - Predictable/reliable supply
  - Fewer brown outs
  - Growing population
  - Meet demand of businesses/residents

- And, are there any concerns that you have or reasons why you think it is perhaps not that urgent that the system be upgraded? Probe for:
    - Degree to which concerns about cost are driving attitudes
- Overall, how confident are you that the current electricity distribution system and infrastructure is adequate to meet electricity demand in the next few years?
- What if I told you that 35 per cent of Toronto's electricity distribution system has past its expected life span? Is this believable? Why/why not?
- How do you react to that information? Probe for:
    - Does it heighten, reduce or not have any impact on the sense of urgency you attach to upgrading the distribution system? Explain.
- Now suppose that nothing was done to upgrade or modernize the electricity distribution system. What would the consequences be, if any, if the system was left as is (i.e. if upgrades or modernization were not undertaken)?
        - What would the impact be on your personally?
        - What would the impact be across the City more broadly? Probe for:
            - Issues with respect to reliability
            - Brown outs/black outs

Extent and nature of upgrades/Perceived benefits/Managing the customer relationship (35 minutes)

- Before this discussion had you heard anything about a 10-year plan on the part of Toronto Hydro to upgrade and rebuild its infrastructure? Probe for:
    - What had you heard?
    - Where did you hear/learn about this?
    - In your view, what is the extent and nature of upgrades or modernization that are required? Specifically, what are the kinds of upgrades you believe are necessary. Elaborate.
- In what specific ways will these upgrades benefit you as a customer of Toronto Hydro? MODERATOR TO LIST PERCEIVED BENEFITS ON FLIP CHART.
- And, specifically, how do you think you personally might be affected by a modernization of the distribution system in your community/neighborhood? How might your streets/homes, etc. be affected?
- I'd like to get a better understanding of what you feel are reasonable and unreasonable disruptions in order to undertake upgrades to the system. MODERATOR TO USE FLIP CHART AND DRAW TWO COLUMS (ACCEPTABLE/NOT ACCEPTABLE DISRUPTIONS. DIVIDE PARTICIPANTS INTO PAIRS AND ASK THEM TO DISCUSS AND REPORT BACK.) Take a few minutes in your pairs to write down what kinds of disruptions or inconveniences you might expect and would be prepared to put up with as well as those that would be completely unacceptable. DISCUSS
- And, now, what kinds of disruptions or inconveniences would you consider unreasonable? What are most "annoying" aspects of these types of projects from the perspective of customers? What bothers customers the most? Please give me some examples. Probe for reaction to:
    - New equipment installed near their property in exchange for more reliable electricity service?
- What kinds of things can/should Toronto Hydro do to address the disruptions? How can inconveniences/annoyances to customers be addressed or minimized?

- Thinking about how Toronto Hydro should communicate with you as a resident through the rebuilding/construction/upgrading process, what kind of information would you be looking for? What are the main questions you would have? (MODERATOR TO LIST KEY QUESTIONS ON FLIP CHART?)
- How many of you are currently affected by an underground rebuild project in your area? Probe for:
    - How have you felt about the communications from Toronto Hydro through this process?
    - Do you have any suggestions for improvement?
    - How would you rate the performance of Toronto Hydro's contractors/workers in terms of courtesy and/or professionalism in conducting their business? Are they any better/worse/same as other contractors you have had dealing with? Elaborate – probe for specific examples/stories that demonstrate participants' assessment.
- And, overall, what is the best way for Toronto Hydro to keep you informed during this process? Probe for:
    - Household mailers
    - Bill inserts
    - Radio/television/newspaper (community newspaper) advertising
    - Online communications (email, website)
    - Telephone Hotline – Probe for:
        - Would you know who to call/where to call regarding an interruption or if you had a concern about an underground rebuild project in your area?
- At what points during the process should information be provided to affected customers? Probe for:
    - How much in advance of construction?
    - Would like to receive an update if the duration of the project spans over a period of 3 months? How about more than 6 months?
    - Upon completion?
- How do you want to be notified about Toronto Hydro's future projects?

Wrap-Up (10 minutes)

- Thinking about our discussion over the last two hours and the current state of Toronto's electricity distribution system, do you strongly support, somewhat support, somewhat oppose or strongly oppose investing to modernize and upgrade Toronto's electricity distribution system in order to ensure reliable delivery?
- For those who support, what is the main reason this should be done?
- For those who oppose, what is the main reason why you oppose any upgrading of the electricity distribution system at this time?

Thank and end session.

FLEET AND EQUIPMENT SERVICES ("FES") CAPITAL PROGRAM

INTRODUCTION:

The objective of the FES Capital Program is to promote an orderly system for purchasing and funding standardized fleet replacement, to plan for future departmental transportation requirements and to support THESL's field staff in carrying out the annual construction and maintenance activities work program. These objectives are supported by the fleet and equipment replacement program, capital tool replacement program, tool crib services, and laboratory services.

Activities to support these programs include:

- Setting Vehicle and Tool Replacement Criteria
- Collaborating with users on replacement and design criteria
- Setting and Managing the Fleet capital replacement budget
- Designing and specifying vehicles
- Preparing purchase requests for vehicles and equipment
- Receiving, preparing, licensing and arranging insurance for new fleet assets
- Reporting the cost and value of new assets to Finance
- Disposing of surplus assets
- Providing equipment, major tools, and consumables to field staff
- Repairing high cost or specialized tools and equipment used by field staff
- Purchase rubber cover-up through the Glove Lab

The total capital costs for the historical, bridge, and test years is shown in Table 1 below.

Table 1: Fleet and Equipment, Tool Crib, Laboratory Capital Program ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Fleet	5,947	8,289	8,471	7,846	7,869
Tool Crib	153	250	175	200	225
Glove Lab	113	100	125	150	175
Total - FES	6,213	8,639	8,771	8,196	8,269

The increase in the Bridge year is attributed to the addition of 20 vehicles to the overall fleet. These vehicles are required to support the additional hiring of Trades and Technical staff to support the investment plans in 2008, 2009, and 2010 as discussed in detail in Exhibit C2, Tab 1, Schedule 6, and Exhibit D1, Tab 8, Schedules 1-8.

Tool costs and laboratory costs remain relatively constant over the bridge and test years, with a modest increase in 2008, and 2009 as the additional vehicles are equipped and come on line.

FLEET AND EQUIPMENT REPLACEMENT PROGRAM

The Fleet and Equipment Program is based on a five-year cycle for capital investment requirements to maintain a safe and efficient fleet, and supporting field equipment. Vehicles are replaced before they become too costly to repair, unsafe and uneconomic to operate, or exceed THESL's fleet life cycle cost.

The vehicle replacement program is evaluated annually against the business plan and is based on annual condition surveys, life cycle planning, and number of repair work orders. Surveys and checklists to detail problems, deficient conditions and maintenance needs are maintained through the use of the Ellipse database as part of the vehicle profile.

The Fleet and Equipment Replacement Program reviews:

- Fleet and equipment capital forecast;
- Fleet and equipment productivity, functionality, and future requirements;
- Fleet and equipment standards, equipment age, mechanical condition, kilometers traveled and cost per kilometer, downtime, and repair time;
- Safety/risk;
- Work programs, evaluating staff and equipment complement;
- Tendered procurement process;
- Original Capital Value and Net Book Value;
- Historical and future utilization;
- Strategic procurement; and
- Cost versus five-year business plan.

The guidelines for vehicles considered for replacement are based on vehicles meeting pre-determined criteria including:

- Large vehicle and mounted equipment replacement criteria
    - Older than ten years
    - Availability based on number of work orders generated annually and hours being repaired
    - Overall vehicle condition assessment
- Small vehicles replacement criteria
    - Older than six years
    - Mileage greater than 200,000 kilometers
    - Overall condition assessment

Other considerations include: manufacturer’s life expectancy, regulated maintenance standards, and beneficial purchasing cycles.

As vehicles reach the targeted criteria, a vehicle maintenance evaluation is performed and, in some cases, the vehicle may be reassigned to other departments with “low usage” requirements.

This organized and structured approach to fleet replacement ensures the utility receives maximum benefit from these assets, meeting the work requirements safely and efficiently, minimizing short-term rental costs, and minimizing operating costs. Purchase of new vehicles and equipment supports an increase in productivity through innovation, improves field crew response time, reduces costs from fuel savings, lowers maintenance costs, and increases environmental responsibility through fuel reduction and alternate fuel usage.

Fleet and Equipment capital costs will increase during the bridge and test years in order to support the increase in compliment, and accelerated work program associated with the workforce renewal discussed in Exhibit C2, Tab 1, Schedule 6, and the 2007-2016 Electrical Distribution Capital Plan, filed at Exhibit D1, Tab 8, Schedule 10.

CAPITAL TOOL REPLACEMENT PROGRAM

The objective of this program is to provide new and replacement major tools (cost greater than $1,000) to field staff. Capital tool costs are budgeted by the Tool Crib on request during the budgeting process.

The Tool Replacement Program is based on a five-year cycle for capital investment requirements to supply effective, and ergonomically correct hand and power operated tools and equipment to inside and outside Trade Staff.

The fixed asset costs associated with this program are required to replace end of life equipment, replace technologically obsolete equipment as new standards and safer work

practices come into effect, and provide for sufficient levels of new equipment consistent with work program expansion and increased staffing levels.

The Tool replacement Program is evaluated annually against the business plan.

The Tool Replacement Program reviews:

- Present inventory and repair history
- Safety and first aid reports related to tool/equipment use
- Changes in work programs
- Efficiency improvement opportunities
- Changes in workforce demographics

In executing this program, staff are engaged in a number of activities including:

- Arranging for the purchase of approved hand tools and small equipment;
- Managing a small inventory of hand tools, small equipment and consumables at each work location for distribution to field staff as required;
- Evaluating new hand tools and small equipment in keeping with good utility practices;
- Evaluating cost effectiveness of high value tools for repair; and
- Repairing, replenishing or arranging repair of high value tools.

Ensuring field staff are equipped with effective tools and equipment to support the work programs, and responding to trends in tool related injuries, is necessary to meet organizational safety and efficiency objectives.

Any major tools required by the Affiliates will be directly purchased by the respective Affiliate through their own Supply Chain process.

TOOLS CRIB SERVICES

Tool Crib Services provides hand tools, small equipment and consumables to field staff on a replacement basis, and carries out repairs on high cost or specialized tools.

On behalf of the Business Units, Tool Crib Services purchases approved hand tools and small equipment through Purchasing, manages a small inventory of hand tools, small equipment and consumables at each work location for distribution to field staff , and evaluates new hand tools and small equipment in keeping with utility practices.

Broken or malfunctioning tools and equipment are repaired in-house when it is cost-effective to do so, or sent out for repair, or replaced.

Ensuring the availability of tools and equipment to field staff is a significant service, helping to minimize crew downtime.

The Tool Crib capital budget for the historical, bridge, and test years is shown in Table 1 below:

Table 2: Tool Crib Capital Budget ($000s)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
153	250	175	200	225

LABORATORY SERVICES

Laboratory Services provides the following services:

- Cleans, inspects and electrically tests insulated tools, insulated gloves and line protection;
- Repairs and calibrates network system protection relays;
- Repairs and calibrates confined space gas monitors; and

- Tracks and maintains supply of insulated material and gloves.

The activities include:

- Cleaning, Inspection & Testing
  - Clean electrically insulated gloves and line cover
  - Physically inspect and electrically test gloves and line cover for defects
- Repair and Calibration
  - Repair distribution network protection relays
  - Repair confined space protection gas monitors
  - Calibrate network protection relays in keeping with network parameters
  - Calibrate confined space gas monitors in keeping with regulation set out by the ministry of labour
- Supply and Tracking
  - Track testing cycles and asset location of electrically insulated assets including personal protective equipment used by field staff
  - Through purchasing replenish failed line protection asset and insulated glove.
  - Ensure the availability of insulated gloves PPE, gas monitors and line cover to field staff.
  - Electrical network fault protection through relay re-calibration

Laboratory costs are charged to users at the time of use and unit costs are charged to departments within THESL**.**

Table 3: Laboratory Capital Budget ($000s)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
113	100	125	150	175

GENERAL PLANT

FACILITIES

The Facilities capital program is intended to provide strategic and operational benefits in support of THESL's construction and maintenance programs.

During the bridge and test years, THESL's construction, maintenance and administrative operations will be relocated from five work centers to three work centers. Existing facilities that no longer efficiently support the work programs going forward, or are sub-optimally located to efficiently support the execution of work programs will be sold. Fifty percent of the gains from the sale of surplus properties will be used to partially offset the cost of a modern, effective multi-purpose work center in the Downsview area, and other capital projects. By 2010, THESL will have sold nine properties and consolidated into three work centers. The transition from the current operation to the future state operation will be facilitated by the lease and occupation of two temporary work centers that offer operational advantages during the transition. A work center at Monogram Road, and another at Milner Road, provide suitable functionality and efficiencies as a result of proximity to the work areas and THESL's customers.

Table 1 below presents THESL's capital costs for the historical, bridge, and test years for the Transition (Monogram and Milner), 14 Carlton upgrades, and 500 Commissioners, expenditures;

Table 1: Capital Costs ($000s)

LOCATION	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test	TOTAL
Downsview		1,000	15,000	12,400	9,800	**38,200**
Carlton		1,500	4,000	1,000	2,000	**8,500**
Commissioners					4,800	**4,800**
Facility Baseline	5,600	3,800	6,300	4,400	5,500	**25,600**
Monogram		1,500				**1,500**
Milner		6,000				**6,000**
Belfield	**SOLD**	0				**0**
Goddard		**SELL**				**0**
Underwriters		0	**SELL**			**0**
Eglinton		0			**SELL**	**0**
Yonge		0				**0**
	5,600	**13,800**	**25,300**	**17,800**	**22,100**	**84,600**

For a complete description THESL's facility plan, see Exhibit C2, Tab 2, Schedule 2.

INFORMATION TECHNOLOGY
PORTFOLIO MANAGEMENT PROCESS AND ANALYSIS

BACKGROUND

In 2006, Toronto Hydro Information Technology & Services ("IT&S") division commenced a new direction towards major transformation. Pre-2006, the focus was on amalgamation, consolidation and stabilization of technologies.

During amalgamation, there were rapid changes to the organization structure, in technologies, and in handling of the Year 2000 (Y2K) associated risks. The focus was to maintain stability amidst the first wave of integration.

Post amalgamation and during consolidation, the electricity industry faced a new challenge around the retail initiative and the technology changes required to prepare for market opening. Additionally, in late 2000 the business transformation initiative started with the implementation of the Enterprise Resource Planning ("ERP") system "Ellipse".

The stabilization period was required to absorb the high rate of change introduced previously, with emphasis on operations and stabilization of systems and the integration of key systems like Supervisory Control And Data Acquisition ("SCADA"), Geographic Information System ("GIS"), and Distribution Management System ("DMS").

The Modernization period began with the appointment of a new Chief Information Officer ("CIO") and the development of a new IT&S direction. This new direction

included a number of initiatives aligned with THESL's strategic objectives, a restated IT mandate, and an assessment of the risks of the current situation within the division.

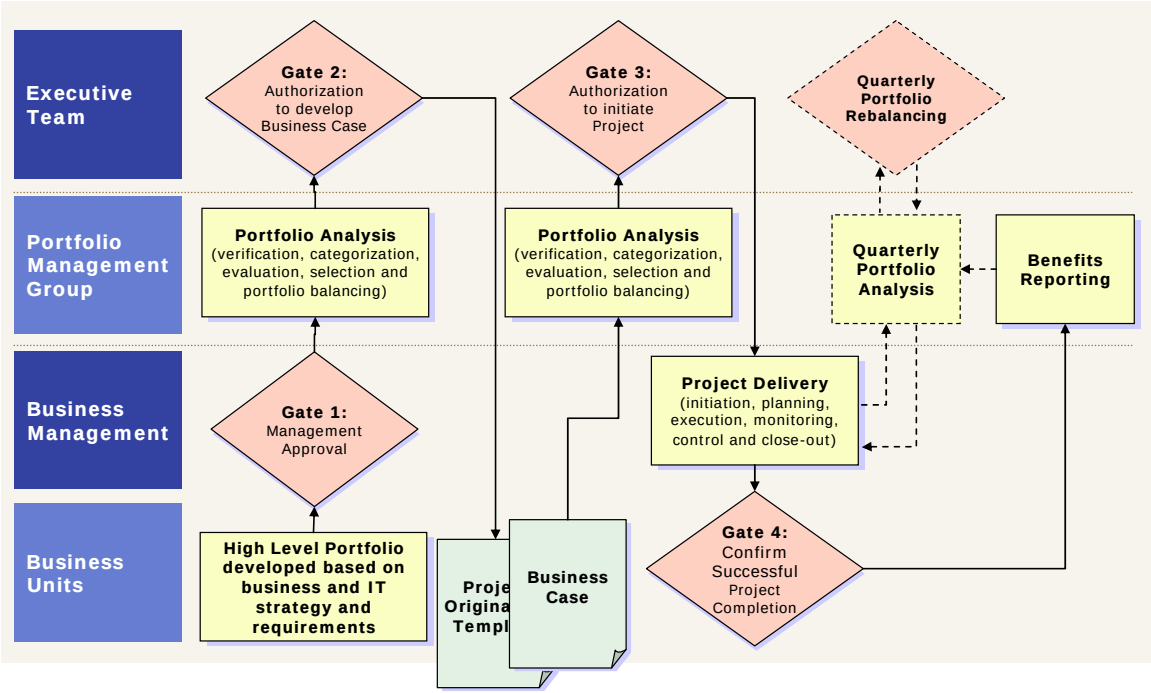
Key components of the modernization plan include rebuilding the leadership and re-invigorating the IT workforce, bringing transparency to resource utilization by separating Program Delivery from Application Support, and establishing distinct units responsible for IT Strategy & Governance, Security and Business Intelligence. In addition, a three-year program (2007-2009) to implement the best practices governance framework Control OBjectives for Information and related Technology ("COBIT") has been initiated.

One of the most critical COBIT components is Portfolio Management, a sub-process of the "Define Strategic IT Plan" process. Portfolio Management enables the translation of corporate strategy into specific programs and projects, and supports improved delivery of identified portfolio benefits. It closes the gap between strategy development and project delivery by translating strategy into an integrated portfolio that is managed for the delivery of objectives.

The process of building this integrated portfolio provides an enterprise view of all the initiatives and eliminates decisions made separately by IT Managers and the business that lead to inefficiencies and ineffectiveness. This Portfolio Management approach facilitates strategic investment decision making, lays the foundation for the realization of benefits within and across business units, and is the basis for the capital expense budget plan for 2008-2010 IT-enabled initiatives. To deliver these programs, individual projects must be managed effectively to meet budget and time constraints. To this end, the portfolio management process was established in 2006, used for the 2007 capital expense planning and adhered to for 2008-2010 portfolio planning.

PORTFOLIO MANAGEMENT PROCESS

The implemented Portfolio Management process is supported by consistently prepared information in the form of Project Origination Documents (initial feasibility studies including ownership, scope, estimated costs and benefits, architectural comments, and preliminary assessments of inherent risk and value) and Business Cases (documentation of the background behind the financial figures, validation of original assumptions, and further elaboration and detail around the problem, proposed solution and considered options and recommendations).



Upon executive approval of the key IT&S programs related to the strategies identified in the corporate plan, these programs are further established and reinforced with a set of resourced projects. The result is the implementation of a particular component of THESL's Business and IT&S strategy. Although the specific projects included in a program are a matter for review and agreement by the executive team, the need for the program itself is not disputed, as it is rooted in THESL's strategy. With approval of the

capital expense budget, the project portfolio is transitioned to the delivery cycle controlled by the Project Management Office of the IT&S Department. Monitoring of the Project Delivery plan provides the required data to assess status of on-going projects, and to rebalance the portfolio as necessary. This ensures that highly-rated, and strategic projects receive the required focus, and that any change to the proposed portfolio of projects is determined based on a pre-defined and agreed upon process.

At project conclusion, and after a sufficient amount of time has passed for the benefits to be realized, the sponsors of each project are required to report on the benefits captured. This information is used to update the portfolio financial information to complete the portfolio analytical cycle.

PORTFOLIO AND PROJECT CLASSIFICATION

The analysis review allows the categorization of the capital project investments into four standard areas (Productivity, Maintenance, Innovation and Growth). This is the same categorization that was used to prepare the 2007 capital expense portfolio.

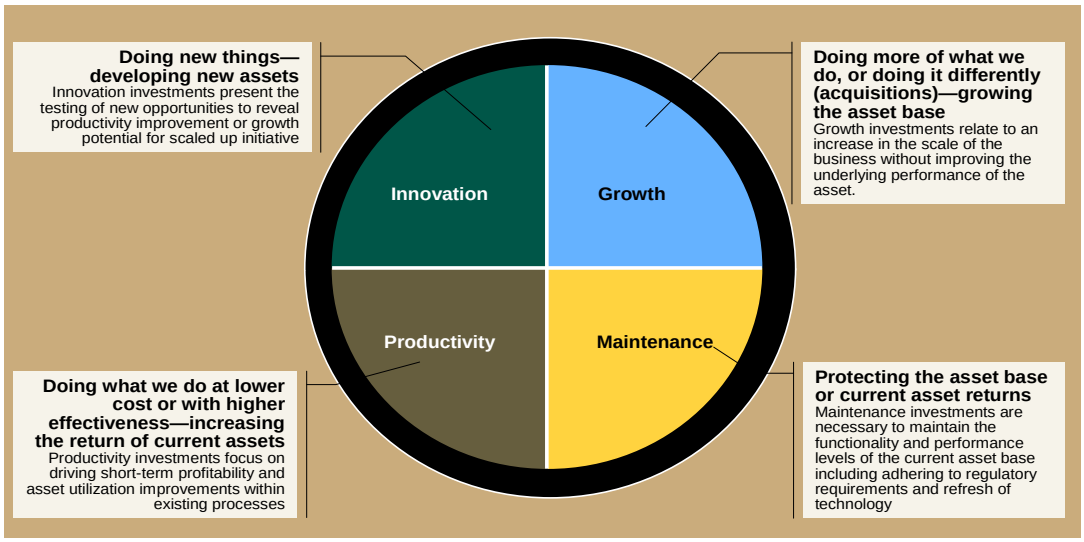


Figure 1: Capital Project Investment Categories

Each project is assessed on its strategic value and risk. Strategic alignment is a means of ensuring that a program is visibly linked to THESL's strategy. The strategic alignment criteria are updated on an annual basis and are a subset of those that the executive team uses to monitor the program's performance. The risk criteria has been developed and agreed to by the stakeholders and is used for evaluating proposed projects. A standard prioritization model takes into consideration financial cost and benefits, risk, value, strategic alignment, and corporate values to determine the overall organization priority of a project.

The results of the prioritization process were reviewed with each of the executive sponsors as well as the executive team (including President, CFO and COO) and final decisions are reflected in the recommended capital expense portfolio.

2008-2010 PORTFOLIO PROGRAM ANALYSIS

The THESL strategic plan articulates four major areas of focus: Operational, Customers, Financial, and People.

The corresponding IT&S programs have been formulated to (a) assist THESL's business partners in meeting their key objectives through the appropriate use of technology and (b) providing these services according to governance policies and procedures that are mandated both internally (e.g., THESL business units) and externally (e.g., regulators and THESL external stakeholders).

The 2008-2010 Portfolio consists of 11 programs with an overall budget of $77.3 million.

The programs are comprised of projects that have been validated via the portfolio management process, assessed on business and strategic alignment and considerations of

project risks, costs and benefits. The three-year capital project investment portfolio are apportioned into 61 percent Productivity and 39 percent Maintenance projects with a trend toward a decrease in Productivity programs and increase in Maintenance programs over the next three years.

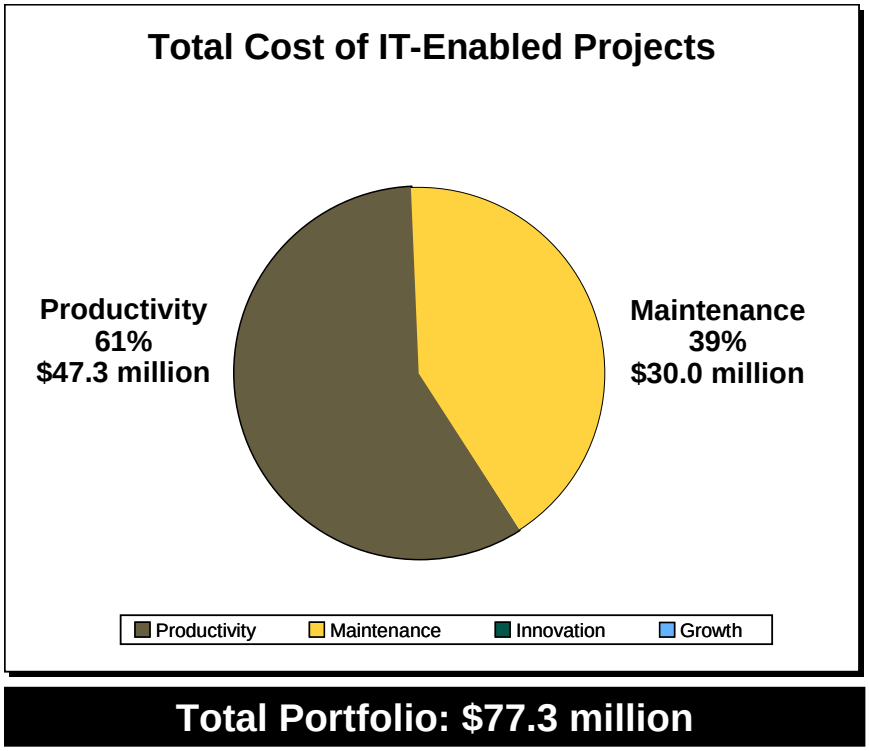


Figure 2: Total Cost of 2008-2010 IT-Enabled Portfolio

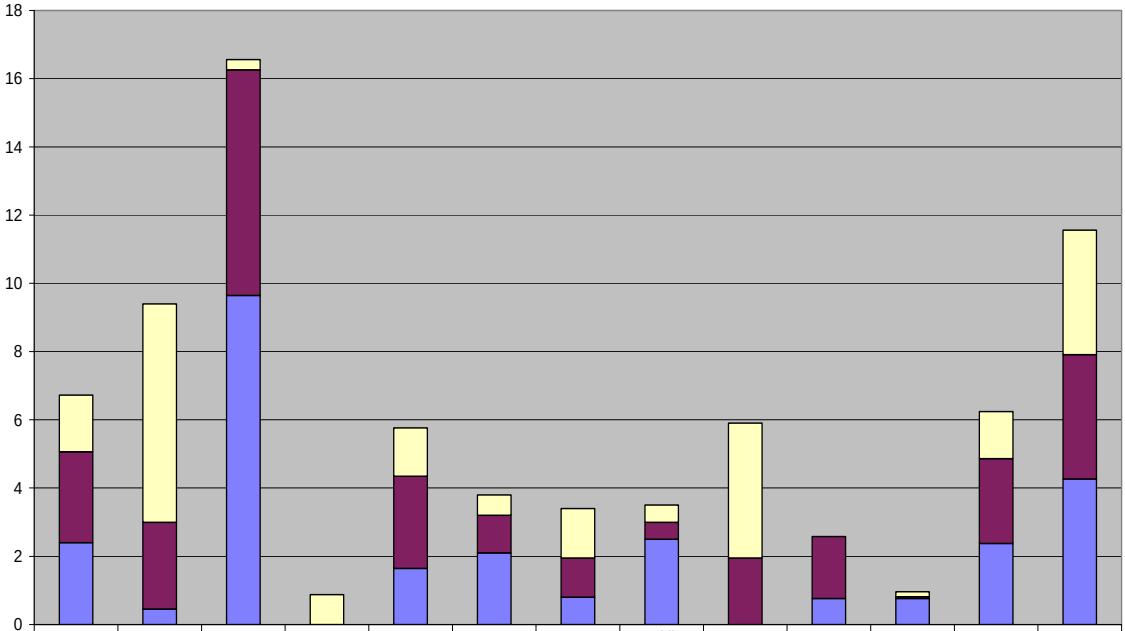
Table 1: Portfolio Breakdown by Investment Category and Portfolio classification ($ Millions)

Investment Category	2008 Test	2009 Test	2010 Test	Grand Total
Maintenance	6.3	9.1	14.5	30.0
Productivity	21.4	18.1	7.8	47.3
Grand Total	27.7	27.2	22.3	77.3

For the first two test years (2008 and 2009) large projects, such as Customer Information System and Infrastructure's Office Refresh, account for a significant proportion of the portfolio. THESL's stated long term objective is to maintain a balance between productivity and maintenance projects. This reflects an effective management of assets, distributed end-of-lifecycle upgrades and availability of funding for efficiency enhancements.

The summary of costs, by year, for each of the major programs that comprise the capital expense budget is presented as follows:

Table 2: Allocation of funds to Programs ($ Millions)



	Business Intelligence	Core Legacy Upgrades	CIS	CRM	Security Program	SOA	Web Enable-ment	Mobile Enable-ment	Contin-gency	HR/OE & Finance	ODS	Infra. Productivity	Infra. Refresh
2010	1.7	6.4	0.3	0.9	1.4	0.6	1.5	0.5	4.0	0.0	0.2	1.4	3.6
2009	2.7	2.6	6.6	0.0	2.7	1.1	1.2	0.5	2.0	1.8	0.1	2.5	3.6
2008	2.4	0.5	9.6	0.0	1.6	2.1	0.8	2.5	0.0	0.8	0.8	2.4	4.3

Descriptions of these programs (2008-2010) are provided in Exhibit D1, Tab10, Schedule 2.

THE 2007 PROJECT PORTFOLIO

The implementation of the Portfolio Management process was initiated in the latter part of 2006 for the 2007 projects. The new process introduced the preparation of Project Origination Documents and Business Cases resulting in collaboration and agreement

between IT&S and the business units who must sign-off on the scope, deliverables and benefits of the project.

Based on the collaboration with the business units, the overall 2007 IT Project Portfolio budget is $20.9 million. The allocation of funds is 38 percent Maintenance and 62 percent Productivity, which aligns with THESL's stated objective of maintaining a balance between productivity and maintenance projects and is in line with the 2008-2010 programs.

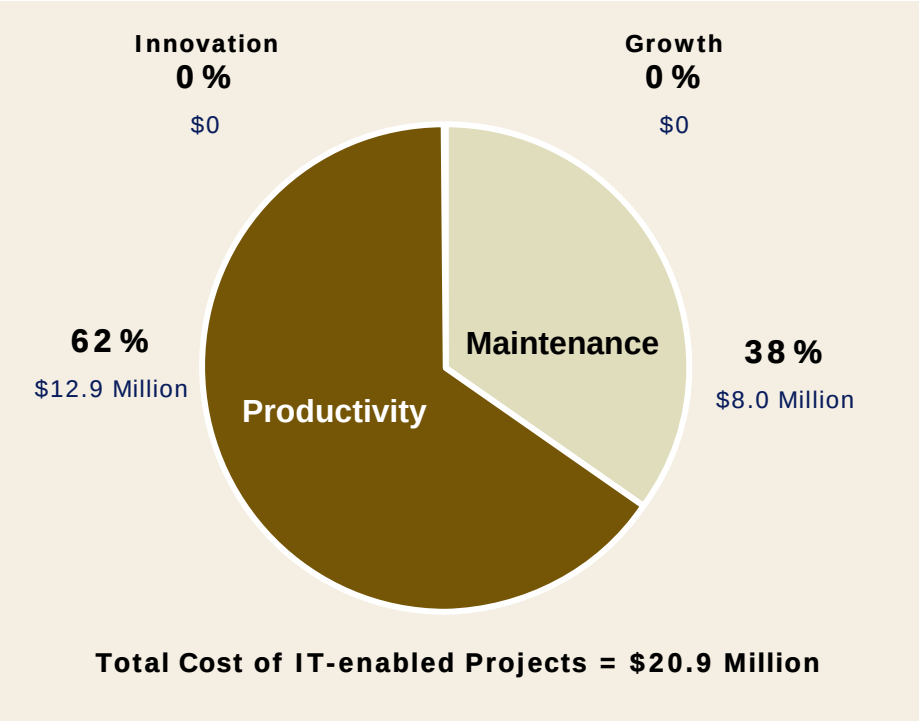
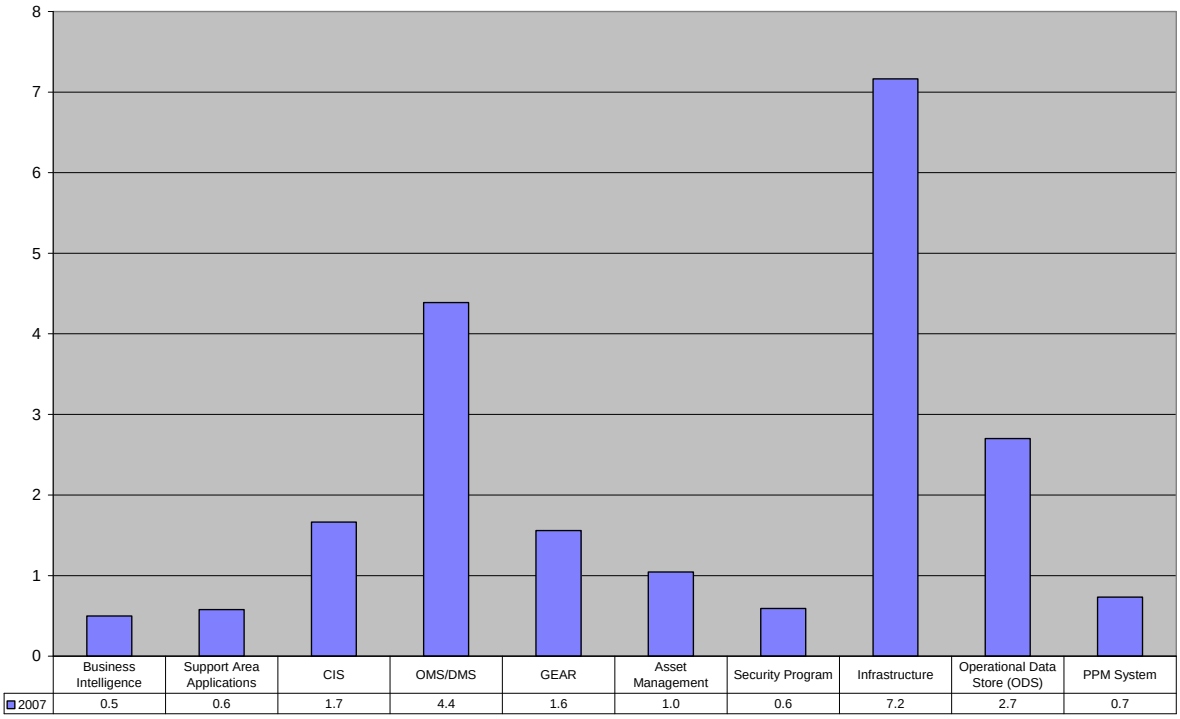


Figure 3: Total Cost of 2007 IT-Enabled Projects

Table 3: 2007 - Allocation of funds to Programs ($ Millions)

Program Name	2007 Bridge
Business Intelligence and Data Management	0.5
Support Area Applications	0.6
Customer Information System (CIS)	1.7
Outage / Distribution Management Systems (OMS/DMS)	4.4
Geo Electric mApping Records (GEAR)	1.6
Asset Data Management & Application Conversions	1.0
Project Portfolio Management System (PPM)	0.7
Security Program	0.6
Infrastructure Program	7.2
Operational Data Store (ODS)	2.7
Grand Total	**20.9**

Table 4: 2007 - Allocation of funds to Programs ($ Millions)



INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

INTRODUCTION OF THE 2008-2010 IT-ENABLED PROGRAMS

The programs described in this schedule have been assembled to provide for the needs of THESL's business partners according to THESL's governance policies. Through the alignment to THESL strategic objectives, balancing the risk and cost of each initiative, and prioritizing each across the company with the full involvement of corporate executive, THESL believes that each of the programs provides significant benefits to the organization. The following figure provides context around the entire IT-enabled portfolio:

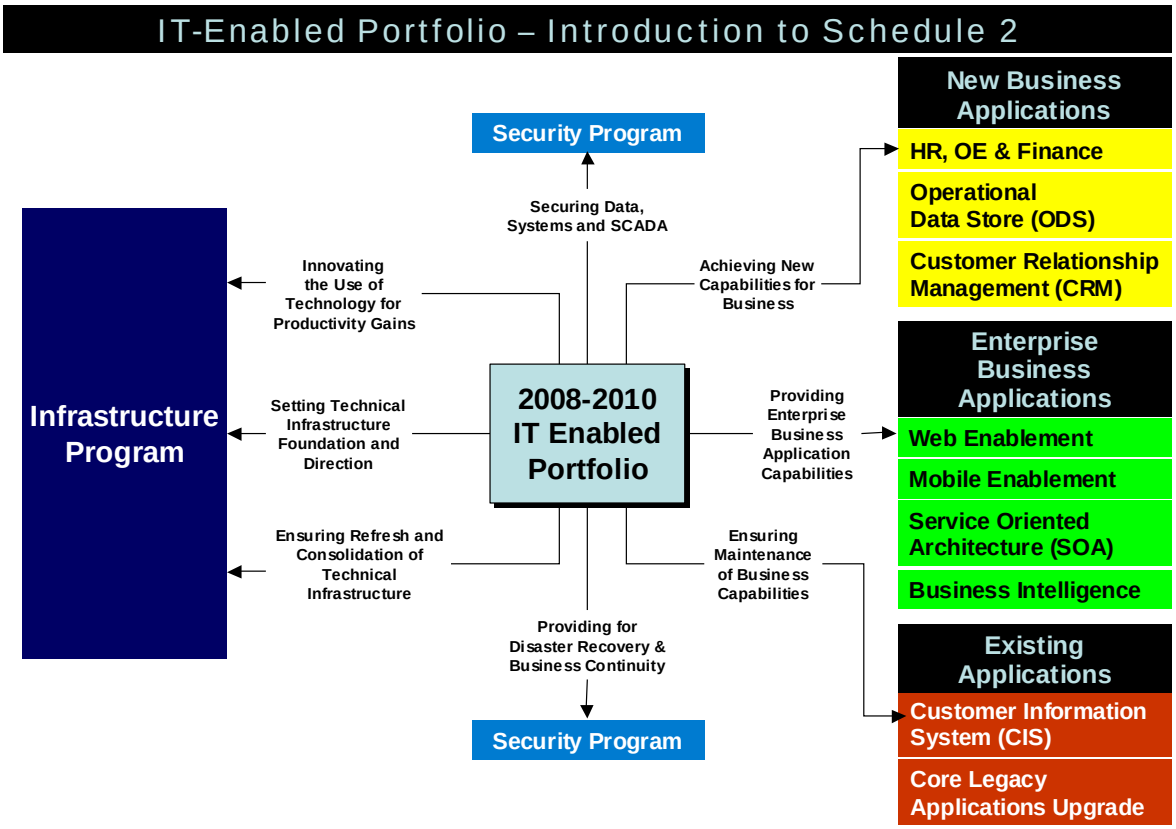


Figure 1: 2008-2010 IT-Enabled Portfolio and Programs

The narratives for 11 programs, provide detail on their requirements, costs, benefits, and timing. There is much interaction between these programs. This interaction and interdependency is managed through the execution of the IT-Enabled Portfolio.

The portfolio delivers each program with specific focus noted within the arrows shown in Figure 1. These can be traced to the program narratives which are provided as part of this Schedule. The programs range from those with specific application requirements (for example implementing the new Customer Information System ("CIS") to replacing THESL's existing applications, or new capabilities within HR and Finance), to methodical replacement of THESL's technical infrastructure. The programs also build the necessary technical architectural base to provide future business capabilities more efficiently and effectively.

While the merits of the programs involving application requirements can be communicated with relative ease, the importance of building a sound architecture, based on a Service Oriented Architecture ("SOA"), cannot be understated. For this reason, the following illustrative introduction to these programs is provided in Figure 2:

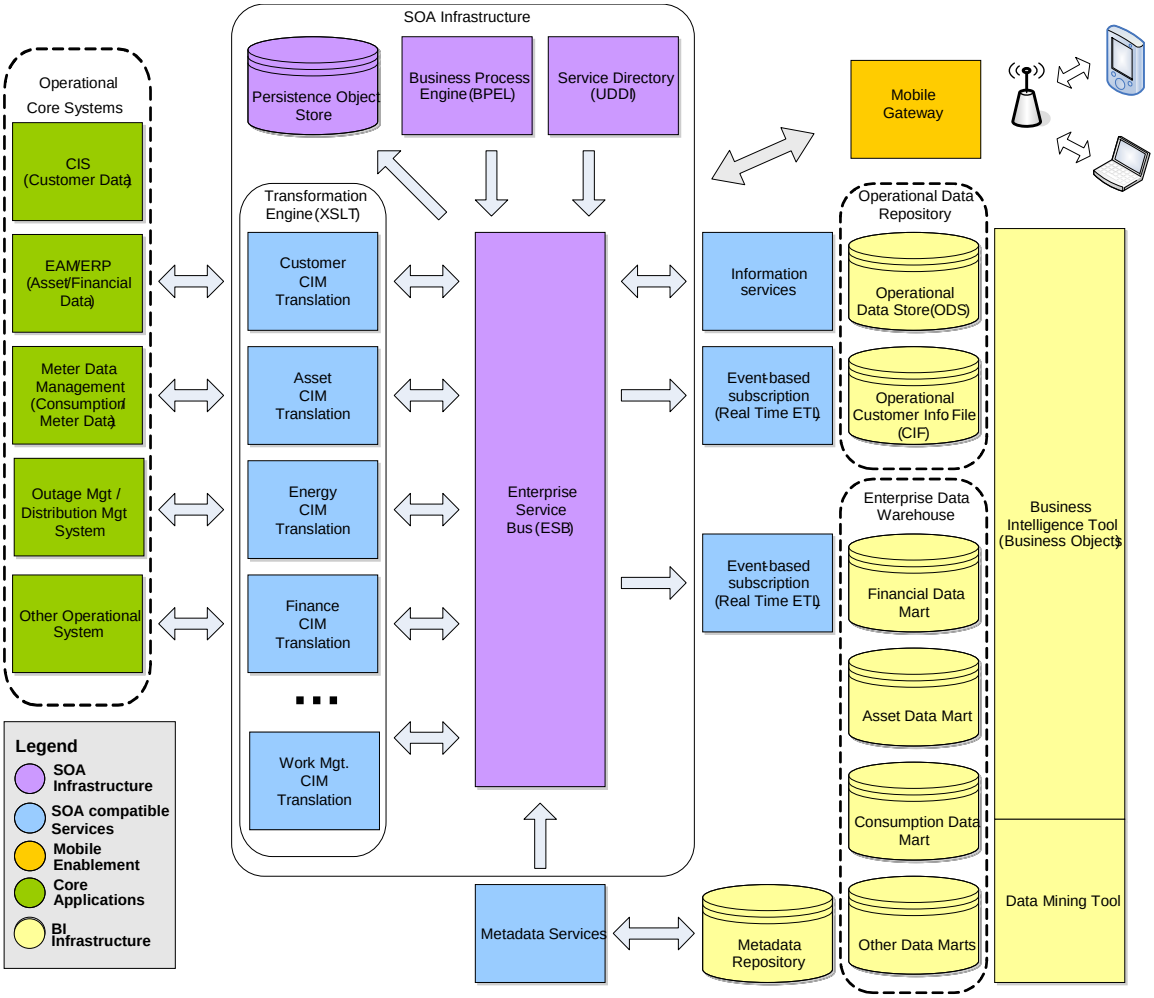


Figure 2: Strategic IT-Enabling Programs

Today the core systems of THESL do not share a common architecture for communication or integration, resulting in many point-to-point interfaces between applications, built over time, as new business requirements have emerged. Each interface is unique to the requirement, to the timing of the updates, format of the transaction, and necessary security of the interaction. An SOA, with applications either written to comply or purchased to standards which support this environment, will provide the ability for

IT&S to respond in an agile manner to the planned and expected business requests in the future.

To permit access to real-time information across the core systems contained in THESL, a number of specific system "services" (shown in blue in Figure 2) will be built, that any other system can use in a secure manner. The services become part of the standard SOA components (shown in purple in Figure 2) that comprise the SOA program.

This initiative is highly strategic as a key enabler across most of the IT-enabled project portfolio. In particular, SOA is the key enabler of the Mobile Enablement, CIS, Security Program, Business Intelligence, Customer Relationship Management, and Web Enablement initiatives, by allowing standard communication with the various application systems delivering business services.

For the Business Intelligence and Data Management program, the strategies for information consolidation, common overall access, search and query capabilities, and subject area Data Marts are implemented. It is important to note that this data exists separately from the live enterprise data and would be updated from the live data as business need and impact on system performance dictates. This program is shaded as the yellow portion of Figure 2.

While specific attention has been placed upon the SOA and Business Intelligence programs, each can only be delivered within an up-to-date and secure infrastructure environment. The setting of a sound technical foundation and providing appropriate and productive use of technology is inherent in the Infrastructure Refresh and Security programs.

The remaining portion of Schedule 2 details each of the IT-enabled programs listed in Table 1.

Table 1: Summary of Overall Capital Expenses of IT-Enabled Programs ($ Millions)

Program Name	2008 Test	2009 Test	2010 Test	Total
Business Intelligence-Data Warehouse, Analytics & Reporting	2.4	2.7	1.7	6.7
Core Legacy Application Upgrades	0.5	2.6	6.4	9.4
Customer Information System (CIS)	9.7	6.6	0.3	16.6
Customer Relationship Management (CRM)	-	-	0.9	0.9
Infrastructure Program				
Infrastructure Refresh	4.3	3.6	3.7	11.6
Infrastructure Productivity Enhancements	2.4	2.5	1.4	6.2
Mobile Enablement	2.5	0.5	0.5	3.5
Operational Data Store (ODS)	0.7	0.1	0.2	1.0
Security Program	1.6	2.7	1.4	5.8
Service Oriented Architecture (SOA)	2.1	1.1	0.6	3.8
Support Area Applications (Human Resources, Organizational Effectiveness, Finance, and Information Technology applications)	0.8	1.8	-	2.6
Web Enablement	0.8	1.2	1.4	3.4
Portfolio Contingency	-	2.0	3.9	5.9
Grand Total	**27.7**	**27.2**	**22.3**	**77.3**

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

BUSINESS INTELLIGENCE – DATA WAREHOUSE, ANALYTICS AND REPORTING

Program Overview

This initiative enables the corporate-wide collection, management, and distribution of essential data. The project will establish IT's Data Warehouse and Data Marts, create the data extraction, transformation and cleansing capabilities. The Business Intelligence ("BI") applications delivered will enable decision support, query and reporting, On-Line Analytical Processing ("OLAP"), corporate dashboard and scorecards, statistical analysis, forecasting and data mining.

This initiative will produce enhanced organizational capabilities to manage data and information as organizational assets. It will enable a more effective and efficient way of supporting organizational information requirements and performance management needs.

During 2007, THESL is planning to create a BI strategic roadmap and determine the incremental deliverables for the program over the next three years. The 2007 initiative will assess the current state of the BI practice and prepare the project plans based on a full analysis for organizational requirements, data analysis with respect to sources and quality.

This program is important because it meets several business purposes:

1) Executive Information System:
    a) Facilitates definition of the hierarchy of business objectives
    b) Enables definition and documentation of business objectives and ranges of desirable performance results

c) Allows executives to focus on exceptions and analyze details of the exceptions

d) Provides ability to measure progress toward strategic goals and effectiveness of current strategies and tactics

e) Ensures compliance and transparency of all reporting

2) Management Information System:

a) Allows management to define goals aligned with strategic direction and objectives of the organization

b) Helps management to define and monitor efficiency and effectiveness measures

c) Allows evaluation of current tactics in achieving strategic organizational goals

3) Operational Information System:

a) Provides all the facts required for the decision maker, for a specific role or specific type of decision, without the clutter of irrelevant facts or cumbersome reports

b) Identifies and documents the information requirements for each role or typical decision

c) Improves productivity and the quality of data, which forms the basis for decisions

The following issues have been identified with the current situation:

- many systems and interfaces
- inconsistent results
- error-prone due to manual processes

- integration of data is time-consuming
- data synchronization is difficult to manage
- timeliness expectations are not consistently met

This initiative will overcome the following compliance, governance, and transparency challenges:

1) Improved quality of information
2) Explicit and traceable audit trail from source data to destination reports such as time-stamping the data, capabilities to rerun partial or entire load jobs, and ability to trace and verify the number of correct records, rows, or transactions being loaded
3) Improved ability to respond to Regulatory issues or queries
4) Consistent interpretation due to explicit and consistent definition of business meaning of data
5) Consistent enforcement of business policy and rules across the organization

The BI and Service Oriented Architecture ("SOA") initiatives have common conceptual, logical, and physical dependencies and mutual support points, some of these are:

1) Common information model for common enterprise level semantics to support a single version of the truth
2) SOA initiative deployment of an Enterprise Service Bus ("ESB") will be used as the enabling infrastructure services to support the Business Information Systems
3) Master data management with a common central repository to record metadata and business rules
4) Reuse of service(s) catalogued in a service registry (e.g., Data Transformation, Authentication Authorization Access ("AAA"))

This initiative is a significant contributor towards achieving THESL's strategic objectives.

Program Description

1) Business data and information requirements gathering and assessment of the organization (2007)

   During 2007, THESL has planned to create a BI strategic roadmap and determine the incremental deliverables for the program over the next three years. The 2007 initiative will align the program with the enterprise direction, assess the current state of the BI practice and prepare the project plans based on a full analysis of organizational requirements, and data analysis with respect to sources and quality. After the initial assessment and BI strategic roadmap is completed, we will be ready to execute against this roadmap starting in 2008.

2) Implement corporate wide BI infrastructure (2008)
   - Refers to the delivery of technical capability as a platform for developing business benefits
   - Includes hardware, software tools, etc. Does not include loading or clean up of data
   - Finance Data Mart ("FDM"). This is an initial Data warehousing project to utilize the Business Intelligence environment, to access the current financial database environment

3) Performance management and information delivery capabilities reporting – dashboards and scorecards (2008)

4) Data consolidation, rationalization, integration and data warehouse modeling (2009)
   - Each of the THESL core systems (ELLIPSE, OMS/DMS, CIS, etc.) has its own database and data warehousing capabilities. These need to be rationalized or

integrated as required to support more flexible and complete business information delivery.

- This project's scope is limited to integration and reengineering at the enterprise level, which will define common integrated logical schemas for the data subject areas. These schemas will be used to develop requirements analysis, data mapping, data transformation rules, and design.
- An enterprise data warehouse data model will be developed, with specific subject area data marts reflecting specific business unit information requirements.

5) Develop automated capabilities to cleanse, move, transform and integrate data (2009)
   - Project will implement a viable practice and enabling technology and deliver the initial data extracts and loads of information from the core systems into the central data warehouse repository

6) Reporting and analytics (2010)
   - Beginning in January 2010, the reporting and analytics requirements from each of the primary business units (Customer Service, Operations, Finance, and Organizational Effectiveness)

Program Costs

The total initiative cost is $6.7 million – with the major component being the labour costs involved with the assessment, analysis, and design of the data warehouse modeling activities. With this in hand, the resulting data warehouse and data mart program will be implemented for THESL.

Table 1: Program Cost ($ Millions)

Business Intelligence	2008 Test	2009 Test	2010 Test	Total
Hardware	0.8	0.5	0.3	1.5
Software	0.8	0.8	0.3	1.8
Labour	0.9	1.4	1.2	3.4
Total	2.4	2.7	1.7	6.7

Program Benefits

- Decrease cost of decision making (manual to auto) through delivery of executive dashboards and on-line analytical capability
- Optimization of collection and gathering of data from all systems
- Increase audit trail capabilities by enabling the business units to follow data through all stages of business process, addressing data quality assurance
- Provide single version of the truth: correct data inconsistencies and decrease user search time through multiple sources
- Separation of business' operational system environments from reporting environment, resulting in system performance and query response time enhancement
- Enable consistent and reliable access to accurate corporate-wide data from disparate sources
- Improve ability to respond to Regulatory issues or Regulator queries
- Improve efficiency in allocation of capital spend (for example, the formulation of a more accurate health index based on information gained from multiple sources within data warehouse allows for improved decision making capabilities)
- Reduce time and labour in preparation and reconciliation of both detailed and summarized reporting
- Improve staff efficiency by separating data management and report preparation activities from data analysis

- Provide tools to leverage customer usage data provided by Operational Data Store ("ODS") capabilities
    - Load Research
    - System Planning
    - Revenue Protection
    - Wholesale Metering Check

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

CORE LEGACY APPLICATIONS UPGRADES

Program Overview

THESL uses approximately 200 applications in the course of its business. Some of these applications are mission critical, including:

- ELLIPSE, the system used for HR, Financials, Asset Management, Work planning and other key business functions;
- Hyperion, vendor of the financial consolidation and reporting system that works in tandem with Ellipse;
- GEAR[1], the GIS[2] system used to map electricity distribution assets;
- OMS/DMS, the Outage and Distribution Management System, used to log and prioritize outage calls, diagnose the problems and dispatch work crews to resolve them;
- BANNER (to be replaced by SPL's Customer Care and Billing ("CC&B") application – see Customer Information System Upgrade), the Customer Information System ("CIS") that supports client interactions (including billing enquiries); and
- PROJECTWISE, the central document repository, where the engineering drawings of THESL's installations are stored.

At regular intervals these systems need to be upgraded. This program is distinct from normal maintenance work which is part of operating expenses. The difference is that these capital upgrades will bring significant new capabilities and functionality.

[1] GEAR refers to Geo Electric mApping Records.
[2] GIS refers to Geographic Information System.

Program Description

The Core Legacy upgrade program includes all major upgrades/modifications that are expected to be required THESL's Core Legacy Applications from 2008 to 2010 in order to address:

- Integration with the new technology architecture
- Vendor upgrades
- Regulatory requirements

Integration with new architecture

A number of strategic technology programs are scheduled for implementation in the 2008-2010 period. These programs are; Single Sign-On, Identity Management, Disaster Recovery Planning, Business Continuity Planning and Service Oriented Architecture. The cumulative effect of these programs will be to change some aspects of the foundation technologies presently in use. Core legacy applications will need to be modified to take advantage of these new capabilities in order to realize the associated benefits.

Vendor upgrades

With the exception of Banner, all core legacy applications mentioned earlier are all supplied by external vendors as Commercial Off-The-Self packages ("COTS") and have been customized to various degrees to meet THESL requirements. In order to maintain support from the vendor, while not burdening users with continual software changes, the strategy is to implement every other major upgrade. This means that each of THESL's major corporate software packages will be upgraded every four years.

The following lists the current status of the Core Legacy Applications from a vendor upgrade perspective and the expected requirement:

- ELLIPSE was last upgraded in May 2006 and is expected to require a major upgrade by 2010.
- GEAR was last upgraded in Nov 2006 to a version of software released in 2004. THESL plans to do a minor upgrade to this software to version 9.4 of Intergraph in 2009 to take advantage of Schematics functionality, prior to considering a major upgrade to Intergraph version 10 after 2010.
- Hyperion is being upgraded in 2007. Further updates to enhance its planning capabilities in relation to new Business Intelligence and Data Warehousing functionality will be required in 2010.
- OMS/DMS is scheduled to be upgraded in June 2007. This upgrade will focus on the "out-of-the-box" application and will not take into consideration THESL-specific customizations that were made to the application. However, these customizations will need to be updated, as well, and this is scheduled for 2009. Specifically for DMS, in 2008-9, validation of Legacy data to and from GEAR and DMS, as well as enhancements to support the Toronto downtown network are planned.
- BANNER will not require any further upgrades, as it is scheduled to be replaced by the new CIS system by 2009/10. However, it will require modifications to account for regulatory changes until such time as Customer Services transitions to the new CIS system. We are scheduling this project in both 2008 and 2009.
- PROJECT WISE was last updated in 2004 and is scheduled to be upgraded again in 2010.

Program Costs

The entire initiative is budgeted at $9.4 million over three years.

Table 1: Program Costs ($ Millions)

Core Legacy Applications Upgrades	2008 Test	2009 Test	2010 Test	Total
Hardware	__	0.2	0.4	0.5
Software	__	0.2	0.5	0.7
Labour	0.5	2.2	5.6	8.2
Total	0.5	2.6	6.4	9.4

Program Benefits

- Regulatory changes must be implemented in order to remain compliant with the regulatory framework
- Integrating Core Legacy Applications with the new architecture is a prerequisite for delivering the full benefits of the new architecture
- Continued Vendor support and realization of improved vendor software upgrades and enhancements to improve user efficiency and effectiveness.

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

CUSTOMER INFORMATION SYSTEM UPGRADE

Program Overview

The Customer Information System ("CIS") Upgrade initiative is one of the major strategic projects in the IT-Enabled portfolio. It supports two of the strategic priorities for THESL, namely Operations and Customer Service.

For THESL, the goal of this project is to replace the existing Banner Customer Information System with SPL's Customer Care and Billing ("CC&B") CIS solution. The implementation of the SPL CIS solution is expected to be executed as a joint development project between Enersource Hydro Mississauga ("EHM") and THESL. A joint CIS implementation with EHM provides several benefits directly to THESL and indirectly to the industry as a whole. The benefits to THESL include lower implementation costs, lower software costs and reduced implementation risk. It also helps in the area of reducing THESL's cost per customer by providing the ability to share future development costs related to regulatory changes.

The indirect benefit to the industry as a whole is the potential for the continued reduction of on-going costs as the other interested LDCs join EHM and THESL in the core CIS Ontario Market Ready solution.

The proposed solution will provide a commercially supported software package that will conform to the Ontario Market requirements as part of the base functionality. The vendor has further agreed to provide the updates to keep the product Ontario Market compliant as part of the regular maintenance fees. In addition to being the lowest cost proposal, SPL was the only CIS vendor who would commit to the ongoing updates as part of the package. The payback to the industry as a whole is significant because the SPL solution

will eventually provide a standard, off the shelf billing system that is compliant with the Ontario Market.

Prior to officially partnering with EHM, a series of LDC meetings were held among London Hydro, Enwin Utilities Ltd., Hydro Ottawa Limited ("Hydro Ottawa"), THESL and EHM to discuss the benefits of developing a core CIS solution. Horizon Utilities and Power Stream Inc. subsequently joined the group. A series of presentations by CIS vendors and their integrators helped the group assess the capabilities of the CIS products for the Ontario market. Additionally, visits to Hydro Ottawa who uses SPL CIS software and Bluewater Power Distribution Corporation who uses SAP CIS software served to confirm SPL's billing system as a good choice for the Ontario market.

As a result of their investigations, EHM and THESL issued an RFP for a vendor to configure, design, develop and implement the CIS for both consortium members in accordance with their common and unique business processes as well as being in full compliance with the Ontario market rules. Of the four vendor solutions that were presented, SPL was chosen.

Moving to SPL's CC&B CIS solution in conjunction with EHM will address four main drivers:

1) The current THESL customer billing system, BANNER, is eight years old, fully depreciated and is supported internally by Toronto Hydro and contract staff. The software vendor at that time (SCT) was not able to provide an Ontario Market Rules compliant system and as a result, Toronto Hydro had to become self-supporting. Internally supporting a heavily customized software platform is a high risk strategy. THESL needs to consider a more current CIS software package that can support the

on-going changes in the Ontario electricity market. This is an opportunity to share all future costs and minimize LDC specific exposure to CIS limitations.

2) Time of Use rates will become mandatory in the near future. With Time of Use rates comes additional customer billing options that will need to be developed and data captured and provided back to customers with relative ease.
3) If THESL remains on BANNER, on-going development costs will be borne entirely by THESL, and there is a risk that BANNER may not be able to provide the new functionality required.
4) There is an opportunity, in the foreseeable future, after the successful completion of the CIS implementation to expand the existing LDC consortium members to continue to reduce operation and development costs and, potentially, to offer a hosted CIS service.

Program Costs

The total initiative cost is $18.9 million. During the test period of 2008-10, the proposed program cost will be $16.6 million.

Table 1: Program Costs ($ Millions)

CIS Upgrade	Total 2006-07	2008 Test	2009 Test	2010 Test	Total 2008-10	Total 2006-10
Hardware	-	1.6	-	-	1.6	1.6
Software	0.7	2.1	-	-	2.1	2.8
Labour	1.6	5.9	6.6	0.3	12.8	14.4
Total	2.3	9.7	6.6	0.3	16.6	18.9

THESL commenced the CIS upgrade program with EHM and has committed several key THESL personnel to the project full-time through the validation completion in the latter part of 2009.

Following implementation of the CIS solution, THESL will undertake the integration of Outage Management to the new CIS application. This is planned for 2010.

Program Benefits

The main benefits of moving to a core SPL CC&B CIS solution and partnering with EHM are:

- The intent is to reduce future overall costs per customer, facilitate regulatory compliance, improve customer service, increase productivity and help demonstrate industry leadership.
- Ability to share equally in the future development costs and achieve a collaborative approach to regulatory changes.
- THESL is in the process of implementing other SPL software solutions, namely Outage Management, Distribution Management and Mobile Workforce Management. It is expected that since all products are from the same vendor, THESL will benefit from both an overall support and from the products' interoperability features.
- Expectations to successfully apply lessons learned from the software implementations for Outage Management, Distribution Management, and Mobile Workforce Management (all products from the same SPL vendor) to benefit the CIS upgrade implementation.

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

CUSTOMER RELATIONSHIP MANAGEMENT

Program Overview

As one of THESL's strategic priorities is customer service, the Customer Relationship Management ("CRM") program aligns the Customer Service department and all other internal business units whose function requires interaction with the customer, meet this corporate objective. With customer interaction expected to increase due to the Smart Meter installations, Time Of Use ("TOU"), individual metering for condominiums and Conservation Demand Management ("CDM"), THESL needs to proactively prepare for CRM functionality that includes Communication and Collaboration, Knowledge base, 360-degree view of the Customer and Analytics. All of which are explained below.

THESL is presently at the early stage of understanding the details of the CRM functionality included in SPL's Customer Care and Billing ("CC&B") product. We are expecting that the Customer Relationship functions of CC&B focus mostly on billing and transactional interactions between THESL and its customers, with limited CRM capabilities. The objective of this program is to ensure that our required CRM capabilities are delivered.

Program Description

Communications and Collaboration

Communications and Collaboration refers to enhancing the company's relationship with the customer and increasing opportunities to communicate easily and improve customer service. The proposed initiative aims at:

1) Self-service options will include billing and payment, move in/out, updating personal information and payment history. Improved communications will be enabled through TOU information and e-Care.

2) Communications with the customer will become more reliable, consistent and up-to-date. It will be in real-time, delivered in several languages and provide a frequently-asked questions section. This makes the system more user-friendly and gives customers the option of how and when they wish to interact with the company. Cost-effective ways of communicating with the customer, e.g., outbound e-mails, will be facilitated.

3) Major campaigns such as Conservation Demand Management, can actively communicate their notices to THESL customers via a “push” of information, but the self service option will allow customers access to their consumption profile, online energy audit tools, their active involvement in Demand Management programs, and smog / health-related tools.

4) Customer Satisfaction Surveys will be conducted more frequently than before, ensuring greater responsiveness to customer needs. The larger survey samples will provide more accurate assessment of the public’s opinions.

The communication and collaboration of CRM requirements will be delivered in very close co-operation with the Web Enablement program. A key consideration is that the CRM program ensures that the back-end information and data is available for use, while the Web Enablement program provides the mechanisms to deliver this information via Web technologies.

Knowledge Base

As customer issues and questions are resolved, notes are added to the issue entry screen, right through resolution. These notes are captured in text format and are indexed for free text search. This means that once IT resolves an issue the first time, a Customer Service Representative ("CSR") can search for, retrieve and use this resolution for other customers reporting the same problem. Depending on the situation, we may decide to provide a similar knowledge-based search capability to the public

360 Degree View of the Customer

This feature consolidates all interactions the company has had with a particular customer and presents them to all internal staff communicating with that customer so that s/he has a complete view of the customer experience. The customer view capability by internal THESL staff is dependent on the function and includes variations of:

- Support Calls
- Issues and their status and disposition
- Billing history
- Payment history
- Change of personal information and address
- Correspondence
- Inclusion in promotional campaigns
- Interaction with our Self Service web site via Web Enablement program

Analytics

One of the programs scheduled for the 2008-10 period is the Business Intelligence initiative. This program will deliver the data warehouse infrastructure that will be used to consolidate and store all information regarding our customers and our interactions. This wealth of data will be mined to deliver Customer-centric metrics such as customer

retention and customer satisfaction, customer behavior trends and conservation promotion.

Program Costs

The total initiative cost is $875,000, budgeted for 2010.

Table 1: Program Costs ($ Millions)

Customer Relationship Management	2008 Test	2009 Test	2010 Test	Total
Hardware	-	-	0.1	0.1
Software	-	-	0.3	0.3
Labour	-	-	0.5	0.5
Total	-	-	0.9	0.9

Program Benefits

- Reduce customer calls by:
  - Proactive communications
  - Increased First Call Resolution
- Greater value delivered to the customer
- Improved trust relationships with customers
- Greater efficiencies in managing the customer – less ongoing maintenance
- Improved brand presence
- More reliable customer profiles on which to test rate base decisions

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

INFRASTRUCTURE PROGRAM

Program Overview

Refreshing technology infrastructure and keeping the backbone of an organization's information technology up to date including servers, computers, software, telecommunications, radio, internet and other network resources, has higher visibility to the business than in the past because most business areas rely heavily on IT support. With Smart Meter, Time of Use ("TOU") and other major initiatives coming on-line, infrastructure demands will only grow.

The Infrastructure Program will enable THESL to attain higher levels of:

- Business Alignment (Smart Meter, TOU)
- Integration (including the SOA and Mobile initiatives)
- Customer Service (Voice System and Call Centre Enhancement)
- Safety (Radio System Enhancement)
- Security and Disaster Recovery (Backup Technical Upgrade, Oracle)

Cost Effectiveness (as new equipment is less expensive to own and maintain)

There are 18 projects in the Infrastructure program, grouped into six areas. Two groups address continued maintenance of the IT infrastructure, while the other four promote productivity enhancements to THESL's technical IT infrastructure.

Infrastructure Refresh Program

1) Office Refresh

Office Refresh is the major expenditure of the Infrastructure program and includes the hardware and software refresh of computers and servers over three years. It will

implement the latest versions of Microsoft Windows Server, Vista desktop operating system and Microsoft Office 2007 suite on updated hardware. This results in significantly increased processing speed and system capabilities, while taking advantage of continuous price reductions of computer hardware over time.

2) Maintenance Projects

These initiatives are required to maintain the usability of the current technology infrastructure and assets. Replacement of older office computer workstations, computer servers and network communication equipment in a rolling inventory cycle is the standard manner of upgrading technology. Regular technology refresh also provides the opportunity to meet growing business demands by acquiring new functionality or achieving the latest technology standards.

- Radio System Enhancements include a proactive monitoring tool for critical components of the system and to implement redundancy for site to site communications for antenna sites. This enhancement will help meet business continuity, disaster recovery and basic redundancy requirements. The upgrade is also essential to provide a reliable, consistent level of service to our customers and to ensure a safe and effective operating environment for field staff.
- Data Network Enhancements will provide additional data ports for connectivity to new servers, maintain data network performance, provide centrally managed and secure wireless access to applications and refresh data centre network equipment. It will also better accommodate data transfer between the two primary data centres and the daily backup process. With Smart Meter, TOU and other impending large-scale projects, it is very important that data systems are in optimum condition in order to meet business objectives. The upgrade is also required to support projects such as mobility and videoconferencing.

- Storage Area Network[1] ("SAN") Capacity Upgrade would accomplish three objectives. The first is to add switches to the SAN to meet growing demands for increased connection capacity. The second is to reduce expenses by moving to a newer and less expensive storage platform. The third is to build on the capabilities provided by the 2007 Tiered Storage initiative.
- Hardware Upgrade – Backup Devices are required to meet governance, business continuity and disaster recovery purposes. The business' growing data requirements must be efficiently backed up in a finite time window while still providing service to all users. At current levels, the hardware backup system will reach maximum capacity in 2008. The solution is to upgrade the backup system and provide higher compression, increased reliability, decreased reliance on manual processes, improved data restore and recovery turnaround and to accommodate increasing business growth.
- Firewall Security Improvements will provide customers with more secure and improved access to THESL internet resources. It will accommodate business growth, provide up to date anti-virus protection, reduce maintenance, qualify for vendor support, meet industry standards and improve reporting.
- 2-Factor Authentication is aligned with THESL's security strategy. To protect Toronto Hydro's most critical information assets, two-factor authentication offers a wide range of user authentication options to help identify users before they interact with mission-critical data and applications. It offers a unique, time-synchronous solution that automatically changes the user's password every 60 seconds. It ensures that only authorized users are allowed entry to the network, whether they require access to Virtual Private Network ("VPN") and Remote Access applications, wireless access points, network operating systems, intranets and extranets, Web servers or applications. This project will also contribute to the

[1] SANs are used to connect and share storage devices; e.g., servers, backup libraries, etc.

Identity Management project within the Security, Disaster Recovery and Business Continuity Program.

Program Costs

The total cost of the Infrastructure Refresh program is $11.6 million.

Table 1: Infrastructure Refresh Program Costs ($ Millions)

Infrastructure Refresh	2008 Test	2009 Test	2010 Test	Total
Hardware	2.2	2.2	2.0	6.4
Software	0.4	0.5	0.8	1.7
Labour	1.6	0.9	0.9	3.4
Total	4.3	3.6	3.7	11.6

Infrastructure Productivity Enhancements Program

1) Backup and Recovery

These projects will provide additional backup and recovery capability beyond the standard daily backup through the use of new software capabilities.

- Oracle Recovery Manager ("RMAN") enables Oracle backups which are compressed, faster to backup and easier to restore than using the current backup technology. Critical Oracle-based applications include Ellipse[2], OMS[3]/DMS, Banner[4], Smart Meter, EMRT[5] and GEAR[6]. RMAN would provide safeguards to protect databases against corruption and crashes and to ensure that they can be recovered and restored within a reasonable time period.

[2] Ellipse is THESL's Enterprise Resource Planning (ERP) system.
[3] OMS refers to the Outage Management System. DMS is the Distribution Management System.
[4] Banner is the customer information system.
[5] EMRT is the Ellipse Management Reporting Toolkit. EMRT provides the reporting for the Ellipse system.
[6] GEAR refers to Geo Electric mApping Records.

- Oracle Data Guard would create a standby database providing failover capability for critical Oracle applications (see above). It would enable automatic failover and switchover between primary and secondary databases, providing more effective disaster recovery. The benefits include minimizing downtime during planned and unplanned outages, high availability, faster disaster recovery, safeguarding against data corruptions and user errors and the standby database can be used for backups and read-only reporting.

2) Microsoft Platform

As part of IT&S strategy to consolidate vendors and reduce operating costs, this group of projects moves towards the Microsoft platform.

- Active Directory Migration from the existing Novell platform would create a standard authentication method and e-mail infrastructure while allowing the company to focus on specific skill sets with a primary vendor. It would align with industry standards, consolidate vendors and enable the full functionality of enterprise tools.
- Microsoft Exchange Conversion would strategically align e-mail to an enterprise class, industry standard platform: Microsoft Exchange (server) and Outlook (desktop). Expected results include lower cost due to new data replication capabilities; increased security features; enterprise class mobile messaging; improved virus protection; ease of deployment; enhanced archive and retrieval capabilities from multiple vendor sources; higher performance; rich functionality and increased scalability.
- SharePoint Collaboration is an on-line collaboration tool which aggregates and organizes information in one place so that users can find relevant information quickly and efficiently. Regardless of their physical location, team members and external parties would have secure, password-protected access to SharePoint internet sites, enabling them to work together on tasks, documents and projects.

- Microsoft Virtual Server divides one physical server (the host) into multiple isolated virtual environments. With Microsoft, each host can hold about 20 virtual servers. THESL can consolidate its vendors, save on software costs and significantly improve vendor support by moving from VMWare to Microsoft Virtual Server.

3) Service Management Optimization

These initiatives are brought forward as a result of potential for future productivity enhancements.

- Change and Configuration Management Enhancements is a major contribution to the IT governance framework. This expansion and upgrade of the Remedy software suite will automate the management of technology and IT process workflow, apportion costs and lower business risk. Among its many features, the software performs a seamless diagnostic of the IT infrastructure, identifying the point of failure instead of having multiple staff conduct time consuming investigations.
- File Services Reorganization would achieve greater data integrity and security. By implementing new file services technology, file servers may be replicated across sites, allowing users to seamlessly access data; content on file servers would be better organized; and faster search capabilities would be enabled. Streamlining the file structure would reduce the risk of losing or duplicating information. There is also an ability to consolidate print services, resulting in less cost and ease of administration.
- Source Management is a solution for developers who want a simple way to manage changes to their source code. When you add a file to the source management system, the file is stored on the database and made available to other users. Team members can see the latest version of a file, make changes to local file copies, and save new versions in the database.

- Linux Migration would consolidate five existing Linux deployments onto one server in a virtual environment. This would create cost savings on hardware, support and facilities and help meet the strategic objective to consolidate the number of operating systems in the environment.

4) Voice Enhancement

- Voice System and Call Centre Enhancements will build on the telephony strategy that started implementation in 2006-7, whereby voice services are moving from a traditional Private Branch Exchange ("PBX") system to the data network.

  Overall, the Voice initiative will:

  - Ensure voice infrastructure has the capacity for future growth
  - Implement productivity enhancing features such as user mobility and video conferencing
  - Enhance Call Centre workflow management and improve reporting on critical statistics
  - Maintain infrastructure for initial Smart Meter call volume
  - Refresh technology for mega-link connectivity
  - Provide proactive monitoring for outage avoidance
  - Implement voicemail redundancy
  - Integrate voicemail and e-mail to a single message store

Program Costs

The total cost of the Infrastructure Productivity Enhancements initiative is $6.2 million.

Table 2: Infrastructure Productivity Enhancements Program Costs ($ Millions)

Infrastructure Productivity Enhancements	2008 Test	2009 Test	2010 Test	Total
Hardware	0.5	0.7	0.3	1.4
Software	0.6	0.9	0.5	1.9
Labour	1.3	1.0	0.7	2.9
Total	2.4	2.5	1.4	6.2

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

MOBILE ENABLEMENT

Program Overview

THESL computer systems' functionality is typically accessed from stationary workstations and laptops connected to the THESL corporate network. The Mobile Enablement program refers to the computing and communications infrastructure and applications necessary to deliver similar functionality through mobile devices. THESL has gained experience through piloting mobile capabilities over the past three years and is well positioned to take advantage of recent developments in this technology domain.

This initiative is a key focus area for process optimization and asset modernization in THESL. It implements a mobile gateway capability and deploys mobile devices to our workforce. This infrastructure would make critical functionality available to mobile users such as the Emergency Trouble Response team and work crews executing corrective or preventative maintenance work, while providing the capability of immediate data access and update to THESL's asset data. These are essential in improving the utilization of both labour and assets, thus increasing productivity, efficiency and ultimately, customer service.

THESL staff is characterized by a highly mobile workforce. Crews move from job site to job site and customer to customer to perform emergency, maintenance and planned work, and metering services. While selective functions in these areas have implemented various pilot solutions, the current work processes are, to a large degree, manual and are not optimized for a mobile workforce. The cumulative productivity gains from the mobile enablement of these work processes will be significant and will result in lower costs and higher quality. This is particularly significant in view of major asset modernization projects that THESL will undertake in the next ten years. For this reason

the mobile enablement program is strategic. It also provides the infrastructure for the following current or proposed projects and processes[1].

1) **General Capability Requirements**

a) Field Requisition (Materials, Equipments and Major Tools): The intent of this solution is to enable crews in the field to directly create a requisition for the materials that they need.

b) Installation and Removal of Equipment: This application has already been developed as a pilot and will be deployed in 2008. The intent is to facilitate tracking of the location of all assets, as part of the asset lifecycle costing model.

c) Labor Costing against Work Orders: Presently, labor costing of work orders is performed manually. With mobile devices available to the crews in the field, they can enter labor costs directly against work orders as executed.

d) Vehicle Costing: Presently, vehicle costing against work orders is performed manually. With mobile devices available to the crews in the field, the crews can enter vehicle costs directly against work orders as executed.

e) Access to Back-End Systems: The mobile device will provide crews with access to enterprise back-end systems, including:

- Ellipse for hazards list, work planner, labor costing against work orders, vehicle costing and materials catalogue
- New Customer Information System ("CIS") for premises information, uploading pictures of site installation and client data.

2) **Outage Management**

Outage Management elements, which will allow THESL to dispatch emergency crews via mobile devices, and remotely enter outage data from field calls into the

[1] Note that in the interest of the cohesiveness of the narrative, we have included progress on current mobile enablement activities.

Outage Management System (OMS) and generate work orders for more permanent repairs.

3) **Asset Data Management**

The Mobile Asset Data Management and Maintenance System (MADMMS) will deploy mobile devices to allow:

- field inspection crews to log asset condition and generate follow-up work requests
- maintenance crews to receive work orders and update the orders to indicate work completion
- field crews to track equipment installation, service and removal using barcodes, and
- all THESL crews to update the Ellipse system remotely to validate asset records against actual assets in the field, reflect asset removal and indicate the potential for asset re-use.

4) **Metering Services and Customer Service Calls**

The Meter and Customer Service element, will provide the ability to schedule meter service and installation activities remotely. This functionality will be extended to customer service calls (e.g., disconnect and reconnect) once the new CIS system is installed in 2009.

Program Description

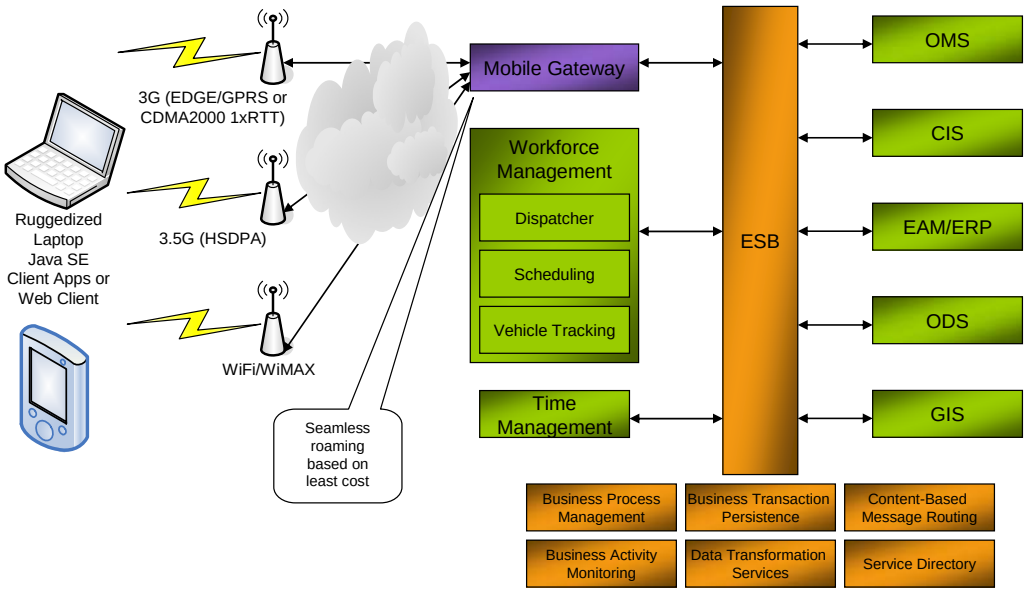


Figure 1: Mobile Enablement Program

A prerequisite for the full implementation of the Mobile program is the existence of the Enterprise Service Bus ("ESB"), the deployment of the Service Oriented Architecture ("SOA") and the integration of existing core applications into the SOA/ESB framework. Vehicles will be equipped with GPS receiver capability as required in 2007.

There are five major initiatives to this program:

1) **Trouble Response** (2008)

   Work on this item has already started in 2007. The scope is to provide a mobile emergency response solution and the integration of Mobile to OMS.

2) **Mobile Gateway** (2008)

The objective is to establish a single Enterprise Mobile Gateway for all mobile applications. This would enable seamless roaming across multiple wireless communication protocols thereby minimizing cost and maximizing access. Queuing would be permitted when wireless channels are occupied, allowing the request to be served by first available channel. It would allow code to be independent of the presentation on the actual handheld device with limited customization.

3) **Back End Integration for SOA** (2008)

This is to provide the development activities to make selected SOA services available to mobile devices and ensure integration with THESL core applications.

4) **Preventative and Corrective Maintenance – Work Order Automation** (2009)

MADMMS will develop the functionality described above in Asset Data Management section (page 3 of this document) pertaining to the creation and updating of work orders from field crews via a mobile tablet device. This includes the incremental cost to equip the crew leaders with 50 mobile laptop devices with replacements as the end-of-life point is reached on existing hardware in the field.

5) **Labour and Vehicle Costing** (2010)

The capability to track and update, in the field, labour and vehicle costs directly to work orders was also described in General Capability Requirements (page 2 of this document) and will yield significant savings over the manual transcribing of time and work orders today. Initial plans are to provide this application to the Maintenance crews only and expand to other construction areas as can be justified. A portion of the cost of the mobile laptop devices noted in point 4 above, is included in this initiative.

Program Costs

The total program cost is $3.5 million over three years.

Table 1: Total Program Costs ($ Millions)

Mobile Enablement	2008 Test	2009 Test	2010 Test	Total
Hardware	0.6	0.1	0.1	0.9
Software	0.8	0.1	0.1	0.9
Labour	1.1	0.3	0.3	1.7
Total	2.5	0.5	0.5	3.5

Program Benefits

There are benefits that can be realized from the Mobile Enablement program, as follows:

- Data gathering at source for equipment identification, data validation, equipment re-use, and installation and removal of equipment will eliminate back-office processing and improve information quality and completeness.
- Mobile processing of inspection and maintenance forms will eliminate the need to print the forms before going into the field and clerical processing of the forms for data entry into Ellipse. An added benefit is the real-time validation on the mobile unit, prior to data entry and therefore reduces need for error investigations
- Elimination of paper-based process for labour and vehicle costing.
- Improved response time to emergency calls by clearing OMS queues faster through mobile updates. This will decrease costs and SAIDI.

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

OPERATIONAL DATA STORE

Program Overview

The Ontario Provincial Government in conjunction with the utility industry developed a number of key programs aimed at conserving electricity and to facilitate load management. One of these programs is intended to encourage electric utility customers to shift some of their energy use away from "on peak" hours through the use of time of use ("TOU") electricity rates supported by a TOU meter. Through this program, customers would have access to their previous day's 24-hour interval data by 8:00 a.m. each business day. In order to support this program, electric utilities must install Smart Meters and other associated infrastructure, which capture energy use by time of day, and allow for the mandated TOU billing, Hourly Spot Price Billing, and/or Retailer Choice for the energy component of the customer's bill. The Smart Meter initiative is based on the Ministry of Energy and the Ontario Energy Board direction.

Specifically, the Operational Data Store ("ODS") program comprises projects that extend the capabilities of the information systems being built for smart meter implementation. Business benefits accruing from these technical projects include operational effectiveness through improved information management, decision support and streamlined business processes in the areas and functions specified below.

Program Description

- Operational Data Store / Data Integration

  Operational processes with the introduction of large volumes of smart meters require that substantial data integration and business process automation be undertaken to address the many new detailed processes and exception handling situations as smart meters are installed, registered with communications services, provisioned for data

collection and commissioned into the customer billing processes. During 2007, the infrastructure base was developed for ongoing ODS development. With this in place, the 2008-10 activities will add new customer types (specifically Commercial and Industrial in 2008) by building upon and also maintaining this framework.

An integrated view of energy use is required that captures the full range of customer installations and metering types regardless of loads or metering infrastructure. Meter changes and Advanced Metering Infrastructure ("AMI") support work require efficient work management and information management support. Operational Data Store / Data Integration support is designed to span the inherent technical differences of various AMI systems and data interfaces to various stakeholder systems. As AMI, Customer Information System ("CIS"), Customer Presentment and Meter Data Management / Repository ("MDM/R") systems evolve to address technical and functional requirements, the ODS & Data Integration components will support this managed migration with minimum disruption to THESL business operations.

Program Costs

The total cost of this program is $964,000 over three years.

Table 1: Program Costs ($ Millions)

Operational Data Store	2008 Test	2009 Test	2010 Test	Total
Hardware	—	—	0.1	$0.1
Software	—	—	—	—
Labour	0.7	0.1	0.1	$0.9
Total	0.7	0.1	0.2	$1.0

Program Benefits

- Supports THESL's Smart Meter Initiative obligations to implement smart meters for all its customers

- Continues the automation of systems needed for the new and modified business processes to both implement and sustain the Smart Meter Initiative
- Creates a unified set of business processes for all metering classes and customer loads.

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

SECURITY, DISASTER RECOVERY AND BUSINESS CONTINUITY

Program Overview

The IT&S security program ensures that the technology environment is not compromised electronically or physically. Security is a key strategic objective for any organization, especially for those providing essential services. For example, a malicious security breach in an electricity distribution station could result in a power outage. Similarly, a breach in the Customer Information System ("CIS") could result in the unauthorized disclosure of confidential customer data. In the event of a natural or man-made disaster, THESL would still need to provide critical services to customers, using its business continuity plan ("BCP") or disaster recovery plan ("DRP"). Although no system can be rendered 100 percent-secure and disaster-proof, THESL is committed to making every effort to mitigate security and disaster risks.

Program Description

There are four projects within the program. Each has the objective of increasing the security, reliability and resilience of our systems.

1) **Identity Management/Single Sign-On** is the largest project in the Security program. It refers to a set of technologies and processes that collectively allow us to:
   a) Create a centralized repository of all users that have been granted access to the environment, including hardware, software, servers, networks and communications
   b) Define the specific services and access levels available to each user
   c) Enforcement of (a) and (b)

- <u>Identity Management/Single Sign-On</u>. This project is comprised of multiple components. It will provide a standard authentication method, whereby consistent

password rules are applied to all applications. It will also enable a single sign-on of user accounts and password synchronization instead of having separate passwords for each application. This will reduce the number of Help Desk and Administrative support calls, improve security and auditing, as well as integration with existing services and applications.

The general Identity Management solution architecture may involve integration of other applications, and will utilize the capabilities of the 2-Factor Authentication project within the Infrastructure Refresh Program. However, the core components will be the following:

- Book of Record is an authoritative source for an identity, or a "point of origin" for the creation of an identity
- Digital Identity Store is a central place where identities from separate applications and systems are stored and linked to provide a foundation enabling identity-driven functionality e.g., user account management, access provisioning, permissions management, authentication and authorization services. User ID's and passwords from the network (Novell), voice mail, Customer Information System (Banner), Ellipse, e-mail (Groupwise) and other applications can be stored in this central single repository (e.g., Light-weight Database Access Protocol ("LDAP")).
- User Management refers to the process of managing user profiles and user credentials on multiple systems and applications across the enterprise. It includes various user administration interfaces, such as delegated administration, user self-service administration and self-service password reset.
- Provisioning refers to managing the access control services on all systems across the enterprise from a single point of control. It is the

automated process of deploying access rights to downstream applications and systems based on business policies and identity roles. It includes the creation, modification and deletion of user accounts, credentials (passwords), attributes (groups, roles) and privileges.

- Security Services is the identity-driven services such as authentication, authorization and auditing. An authentication service verifies the identity of the user and determines if the user is allowed to access the requested application or resource. An auditing service ensures that all identity-based activities are properly logged and/or forwarded to a central place for analysis.

2) **Supervisory Control and Data Acquisition ("SCADA") Security** refers to the technological security of the electricity distribution infrastructure. Unauthorized system access is a primary security concern.

- SCADA Security. The ("SCADA") system electronically controls much of the electricity distribution throughout the GTA. SCADA is used by the control room to turn off switches, bring down circuits etc. at remote sites. The goal is to ensure that the system cannot be electronically compromised. This project will enable THESL to further enforce consistent security policies and demonstrate effective controls through auditing, logging and reporting.

3) **Security Command Centre ("SCC") Tools Deployment** refers to the IT environment including software, computers, servers, networks and communications. A security breach in the IT infrastructure would result in either productivity loss through service denial (users may not be able to access network resources reliably) or in the unauthorized access to our applications resulting in access to confidential data. The goal of IT security is to mitigate these risks.

- Security Command Centre (SCC) Tools Deployment. The objective of this project is to implement the security plan in the context of a single, consolidated, central security environment. This includes a Security Information Management

solution, network security enhancements and IT continuity and backup design. Security Command Centre tools with risk analysis capabilities will be deployed to monitor and report security threats. The solution will comply with Control OBjectives for Information and related Technology ("COBIT"), Bill 198, Personal Information Protection and Electronic Document Act ("PIPEDA") and other Ontario Energy Board requirements.

4) **Disaster Recovery Planning and Business Continuity Planning**. Disaster recovery planning refers to the people, processes and technologies involved in restoring service to users once an IT system has been disrupted. Business continuity planning focuses more on alternative ways of continuing our business in the absence of computer systems or in the event of a non-IT related crisis. Although THESL has a disaster recovery environment, it must be updated with current threats and vulnerabilities that may impact THESL.

- Disaster Recover and Business Continuity. The objective of this three year project is to deliver the Disaster Recovery plan, identifying areas of improvement and implementing applicable tools and technologies. In the process of designing the DRP solution, we will also identify hardware and software requirements of the BCP that need to be implemented. The project includes the following core activities:
  - Review the current state of the DRP/BCP program;
  - Identify and evaluate current threats to the conduct of business activities and the use of technology;
  - Business impact analysis to identify critical business resources and key continuity requirements including hardware and software needs;
  - Architect, design and implement necessary redundancy in hardware, software, or other technology tools required;
  - Document the high level procedures for responding to, controlling and managing emergency situations; and

- Facilitate awareness among THESL staff, including the use of tools and technology.

Program Costs

The total cost is $5.8 million over three years.

Table 1: Program Costs ($ Millions)

Security Program	2008 Test	2009 Test	2010 Test	Total
Hardware	0.2	0.3	__	0.5
Software	0.4	0.2	__	0.6
Labour	1.0	2.2	1.4	4.7
Total	1.6	2.7	1.4	5.8

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

SERVICE ORIENTED ARCHITECTURE

Program Overview

Service Oriented Architecture ("SOA") is an IT strategy that organizes the discrete functions contained in enterprise application into interoperable, standards-based services that can be combined and reused quickly to meet business needs. Without this architecture, the multi-business unit integration of computerized systems is heavily constrained, requiring special application customization for each point of integration and lacking an overall security framework.

In developing a common communication and data architecture, requests for automated business services can be designed independent of the external applications involved, as long as these requests correspond to the standards agreed upon by the organization. This is physically implemented through the use of an Enterprise Service Bus ("ESB"), which will be deployed for use by the Smart Meter project in August 2007.

With ESB in place, the primary activity during 2008-10 is enabling of candidate enterprise applications functions as reusable automated business services. Furthermore, the Common Information Model (designed in the Smart Meter initiative) will be extended for use across all business units of THESL, providing the definitions, methods of access, and ownership of the essential data required for the enterprise. With this model in place, rules and transformation processes are developed using common infrastructure services to accept messaging and file transfer interfaces to allow independent access to participating applications.

Application use of Common Information Model under SOA

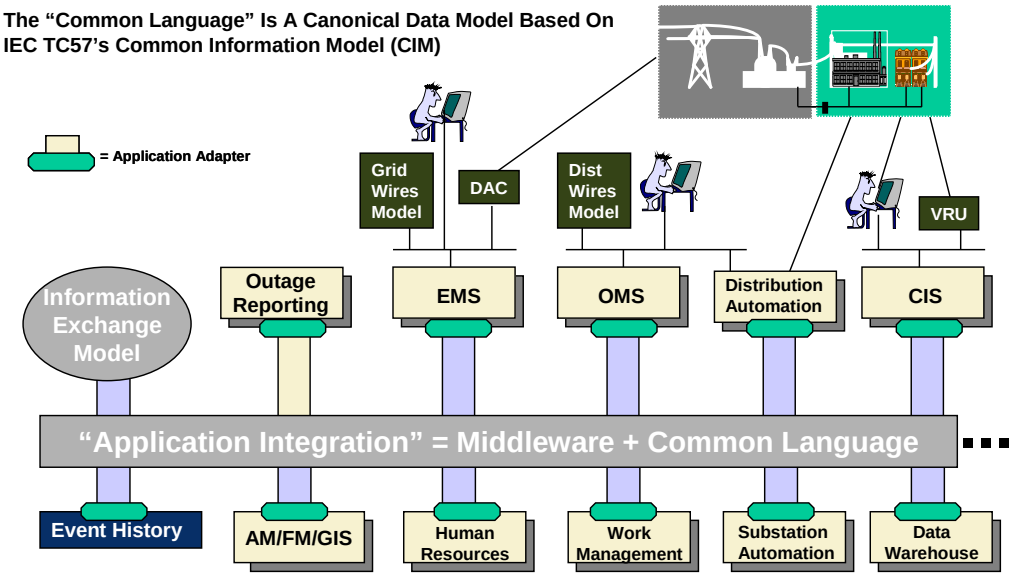


Figure 1: Application Use of Common Information Model under SOA

Today the core systems of THESL do not share a common architecture for communication or integration. This has resulted in many point-to-point interfaces between applications – built as new business requirements emerge. Each interface is unique to the requirement, as to timing of the update(s), format of the transaction, and necessary security of the interaction. The integration point also requires extensive knowledge of both systems involved in the transaction, in order to understand where the information resides, and the impact of making an update. An SOA – with applications either written to comply or purchased to standards, which support this environment – will provide the ability for IT&S to respond quickly to planned and expected business requests in the future.

This initiative is a key enabler across most of the IT-enabled project portfolio. In particular, SOA is the key enabler of the Mobile Computing, Customer Information

System, Security Identity Management, Business Intelligence, Customer Relationship Management ("CRM") and Web Enablement initiatives, by allowing standard communication with the various application systems delivering business services.

Program Description

This project will deliver on plant and customer directories enabling master data management across the enterprise for asset and customer data.

The project also involves enhancing the Common Information Model ("CIM"), initially developed for the Metering segment of THESL operations under the Smart Meter program. CIM aligns the THESL data usage and definition with industry practice. There are several Industry Vertical Common Information Models in existence that can be reused for THESL purposes. THESL is currently using the International Electrotechnical Commission's IEC CIM 61968 as the standard distribution utility model. As the CIM is developed, other standard models may be augmented for use such as: Metering (using OpenAMI), Enterprise Resource Planning focus (using OASIS 9.0), and Geographical Information System (using Open Geospatial Consortium's OGC GML 3.1.1).

IT&S will deliver the components of this initiative in a way that will achieve benefits to the business throughout this project (instead of waiting until all components are fully completed). For each application integration and/or service enablement of application components activity, the development cycle will include the following main activities:

CIM determines the business unit responsible for a particular data element, agrees on the official book of record and definition, and the synchronization rules with propagation and time limits for data updates.

The CIM data focus is on the interfaces between applications, not data structures internal to applications. This is a very labour-intensive activity, as the design work needs to cover the reference point for all data communications between THESL core applications that hold common data objects.

The Business Rules Engine component is a standard SOA development which concentrates on separating key business rules from their specific application, which allows all applications to apply the rules consistently, without additional programming, and which clarifies exactly how the rule is to be applied. Each application will have its contribution to the rules that would reside within this environment.

The Transformation Engine enables real-time and batch transaction reformatting and data transformation to allow information to be processed in a consistent manner. Each application will be provided with the methods required to translate information both to and from the system which allow independent actions between each system.

Business Process Management ("BPM") enables the creation of business processes that coordinate between people, applications and services.

There is a separate parallel task which is not directly an SOA activity, but is essential in ensuring that interfaces are in place between two core systems as soon as possible to address an existing data integrity problem. The Geo Electric mApping Records ("GEAR") to Ellipse integration project is designed to address, in batch mode, data integrity problems and bring them to a sustainable point, starting in January 2008. Once these systems are at a common point of reference, they can be kept consistent while the SOA infrastructure is established, and the applications themselves can use this infrastructure.

Program Costs

The total initiative cost is $3.8 million – with the major components being the labour costs in the design and implementation of the Common Information Model for THESL.

Table 1: Program Costs ($ Millions)

SOA	2008 Test	2009 Test	2010 Test	Total
Hardware	0.2	-	-	0.2
Software	0.3	0.3	-	0.6
Labour	1.7	0.9	0.6	3.1
Total	2.1	1.1	0.6	3.8

Program Benefits

- Reduce IT&S time and labour in development through reusable components
- Improve quality of software delivered with reusable modules
- Enhance security practices via reusable and centrally managed code
- Modernizing and simplifying the environment through adoption of Open Standards concepts of SOA

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

SUPPORT AREA APPLICATIONS

Program Overview

Support Area application initiatives include the following divisions: Human Resources ("HR"); Organizational Effectiveness ("OE"); Finance; and IT&S. To better support these business units, customers and meet regulatory requirements, various technology improvements are proposed. The nine Support Area projects involve automating processes or achieving significant improvement in user functionality. This will increase data reliability and reduce time, labour, duplication and data entry across all systems. It will also enable data capture and analysis.

Program Description

The program includes the following projects:

1) OE and HR
   - Automate the process used to calculate performance management and incentive compensation.
   - Implement a long range planning tool to analyze, forecast and plan resource needs over a ten- to 15-year time horizon. The tool would create models for different workforce scenarios, forecast anticipated retirements and track compliance with the approved plan.
   - Implement an enterprise-wide tool to capture action log commitments and performance contract objectives in one centralized location. Individuals could track and update their action items; managers could monitor staff work load and progress.

2) Finance[1]

- Build interfaces to connect existing Finance systems. Instead of entering information separately into each system and then manually consolidating, information would be uploaded and synchronized, thereby improving data reliability and processing times.
- Automate the consolidation of financial reports, instead of using Excel spreadsheets. In their current configurations, the existing Finance systems cannot perform this function. Automating the process would increase data reliability and reduce time, labour, duplication and data entry across all systems.
- Implement an improved, user friendly workforce planning tool. It would enable budgeting, forecasting and modeling of payroll costs, available work hours and headcount. Finance, HR and the various business units would be able to easily view, validate and edit their own information and create their own workforce modelling covering, for example, additions, termination, attrition and maternity leave.
- Automate the expense claim and corporate credit card process, including the tracking of expenses to project cost centres. Instead of submitting expenses by paper, employees would use an on-line form which would automatically route to their manager for on-line approval. The web tool would upload to the Ellipse financial system, expediting payment and significantly reducing data entry and manual journal entries.
- Procure an enterprise governance tool for the Internal Audit, Risk Management and IT&S areas, in particular to meet Bill 198 requirements. The tool would provide a central repository for processes, risk assessment, tracking controls, metrics, reporting and other activity. Although Finance is the project sponsor, the intent is to eventually leverage the tool and its related processes across THESL.

[1] The major Finance systems are the Hyperion suite of products, Ellipse and EMRT (Ellipse Reporting).

3) IT&S

- Approved for 2007, the Project Portfolio Management ("PPM") project will implement an automated tool to enable portfolio management, project planning, resource management, cost management, and connection to a scheduling tool. The 2008 PPM request relates to the change management and initial team member training required as part of the 2007 system implementation. Although IT&S is the project sponsor, the intent is to eventually leverage the tool and its related processes across THESL.

Program Costs

The total cost for the Support Area Applications program is $2.6 million over three years.

Table 1: Program Costs ($ Millions)

Support Area Applications	2008 Test	2009 Test	2010 Test	Total
Hardware	0.1	0.1	-	0.2
Software	0.2	0.5	-	0.7
Labour	0.5	1.2	-	1.7
Total	0.8	1.8	-	2.6

Program Benefits

Efficiencies and savings are expected to be captured in the future once the technologies are fully deployed and users develop facility with them.

- Ensure accuracy and consistency of data across the enterprise by using the same data source.
- Reduce time and labour spent on manual processes and enable staff to work on more value-added tasks.
- Increase quality by reducing risk of human error inherent with manual processes and hand-offs between business units.

- Reduce turnaround times by automating manual processes and enabling users to access information on-line in order to perform their jobs.
- Standardize work practices across the enterprise.

INFORMATION TECHNOLOGY PROGRAM DESCRIPTIONS

WEB ENABLEMENT

Program Overview

The current state of the company's web infrastructure is outdated and has fallen behind industry benchmarks. A cost-effective strategy is needed, focusing on empowering employees and making them more productive and better coordinating their activities. This initiative will allow the company to meet changing customer expectations in terms of Web technology.

THESL will invest in the Web infrastructure of the company to modernize the utility, improve customer services through the use of web communication, promote financial strength through enhanced cost effectiveness, ultimately generate benefits for the customer, and indirectly improve the health and safety of THESL employees by opening new web platforms to convey company standards and objectives.

These objectives relate to both customers and employees. The main focus for the customer will be the ability to use the web for self-service including access to customer Time of Use ("TOU") data, and on-line educational and conservation materials. For the employee, a more efficient and effective platform will improve communication by enabling self-service applications for access to HR and benefits information, an enhanced interface to the Ellipse Enterprise Resource Planning system, and better dissemination of information, policies, and educational materials.

Program Description

This investment is required to identify and establish a defined approach to internal and external web enhancement projects. As a result of this project, a standardized list of

software, hardware, applications, and development tools will be selected to achieve the business objectives stated below:

- Incorporate content management and portal tools;
- Apply and market new uses of the internet domain;
- Maintain a clear distinction between affiliates through the incorporation of and adherence to Affiliate Relationship Code ("ARC"); and
- Enable business owners to more effectively manage customer content.

The Web enablement program focuses on Customer and Employee relationships.

Customers

Areas of focus will include: Self Service, Communications, Transparency, Conservation and Analytics and Brand Management.

Self Service, Communications and Transparency

Helps to enable the efficient implementation and optimizes the effectiveness of Customer Relationship Management ("CRM") initiatives. The following features are included:

- Using Smart Meter data, will allow users to view their up-to-date TOU information, promoting demand management.
- Through Outage Management System ("OMS") integration, allows for the sharing of real-time information with customers (e.g., updates on outages) improving customer satisfaction and communication during emergency and recovery situations.
- E-care suite containing self serve features – e.g., the ability to manage bills online including viewing bills, payment, updating personal information, viewing payment history resulting in fewer customer calls.

- Outbound e-mail system, a cost-effective way of communicating with the customer, for example Conservation initiatives and tips, participation in Demand Management program.
- Rate application postings will improve transparency between company and the public.
- Offering content to customers in other languages.

Analytics and Brand Management will enable the efficient capture of individual customer consumption histories, the consolidation of such data, its analysis and interpretation. This will allow customers to be segmented according to consumption profile, and ensure the effective alignment and deployment of THESL service offerings to customer needs.

Employees

The aim from an employee perspective will be to maximize the overall effectiveness and productivity of the work force. Areas of focus will include: Self Service, Workflow Improvement, Engagement and Communication, Business to Business ("B2B")/Business to Customer ("B2C") and Dissemination of Information.

Self Service will create effective and efficient features via the Internet by having a single point of access, improving user-friendliness and navigation. This will include the following features:

- Procurement interface to order business cards, name plates, etc.
- Staff-administered data input features - vacation requests, personal information updates, expense claims, etc.
- Customer Service Representative access to Smart Meter –TOU information and E-care

- Online dashboards for both employee and executive Key Performance Indicators (from OMS, Customer Information System, etc.)

Workflow Improvement will enable overall improvement of work force productivity through better communication and coordination. This includes:

- Back-office improvements such as Enhanced Ellipse User Interface will enable staff to administer data efficiently;
- Collaborative working environments through real-time communication from crew-to-crew or employee-to-employee; and
- Online sharing of project status and information.

Engagement and HR Communication will improve service to existing employees and attract future staff. Features include:

- Online training videos;
- Online access to material, which employees require, such as news feeds and trade journals; and
- Modified careers website.

B2B/B2C will improve efficiency and effectiveness of projects with the City of Toronto, other utilities, suppliers and other organisations via enhanced supply chain capabilities. Proposed improved features include:

- Fleet maintenance procurement – purchase of vehicle parts directly from suppliers;
- Plant locates – through Ontario One Call, outside contractors have direct access to THESL plant information; and
- Utility attachments – Collaboration with other utilities via joint ventures will be facilitated.

Dissemination of Information will enhance the individual's ability to source information in a timely fashion. Areas targeted will include:

- Regulatory Compliance;
- Corporate Governance and Policies;
- Reporting – Environment, Health and Safety ; and
- Contact info/search.

Program Costs

The total cost of this program is $3.4 million over three years.

Table 1: Program Costs ($ Millions)

Web Enablement	2008 Test	2009 Test	2010 Test	Total
Hardware	0.1	0.2	0.2	0.5
Software	0.1	0.3	0.1	0.5
Labour	0.6	0.7	1.1	2.4
Total	0.8	1.2	1.4	3.4

Benefits

- Stronger relationship between THESL and its customers and employees;
- Conservation promotion;
- Alignment with industry benchmarks;
- Measure increased labour productivity through employee empowerment, workflow improvement, coordination and collaboration;
- Improved Customer service and HR efficiencies through self-service offerings; and
- Overall optimization of the efficiency and effectiveness of THESL.

CONTRIBUTED CAPITAL

Table 1: Contributed Capital ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Opening Balance	2.0	2.0	2.0	7.5	18.0
Contributed Capital	-	-	5.0	10.0	20.0
Ending Balance	**2.0**	**2.0**	**7.0**	**17.5**	**38.0**

Contributed capital during the test years will be paid to Hydro One Network Inc. ("HONI"). Refer to Exhibit D2, Tab 1, Schedule 1 for additional information.

TREATMENT OF CAPITAL GAINS AND LOSSES

TREATMENT OF GAINS AND LOSSES

Gains and losses on retirement, or on disposal, of assets are credited or charged to "other" in the statement of income.

Gains on disposal of assets reflected in this application have been shared between ratepayers and the shareholder on a 50/50 basis. The OEB has indicated that this is the generally expected treatment of gains on sale (Board Report, RP-2004-0188, p. 27).

DEPRECIATION OR AMORTIZATION RATES

AMORTIZATION RATES

The amortization rates outlined in Appendix B of the *2006 Electricity Distribution Rate Handbook*[1] ("DRH") published by the OEB are applied to historical and projected capitalized expenditures.

The DRH is silent on the amortization rates related to capitalized software and land rights expenditures. THESL's *Computer Software Capitalization Policy*, which is included as Appendix A, describes the accounting policy and recommended treatment for software expenditures. Paragraph 1.6 of this policy outlines the amortization period applicable to capitalized software costs. Land rights are amortized over 50 years.

Capitalized expenditures related to smart meter implementation costs will[2] be amortized over 15 years as directed by the OEB.

[1] Dated May 11, 2005.
[2] Amortization of smart meter costs have been projected to begin in 2008.

SUBJECT: Computer Software Capitalization Policy	Date prepared: 2005/08/12 Date revised: 2006/11/29	Page 1 of 5 DRAFT

Authorization:		
Approved By:	Corporate Controller, THC	Chief Financial Officer, THC
Date:	2006.12.14	Date: 2006/12/14

1.0 Computer Software Capitalization Policy

1.1 Purpose

To establish the accounting policies and recommended accounting treatment to account for computer software. To ensure expenditures are appropriately capitalized on the balance sheet (capital) or expensed to operations in the period incurred (expense).

1.2 Scope

The accounting policy should be applied to all companies within the Toronto Hydro Group, as applicable.

1.3 Ownership and responsibilities

1.3.1 This policy is owned by the Corporate Controller and will be managed by the Controller of each affiliate, who might delegate it to the subject-matter expert staff member.

1.3.2 The Corporate Controller is responsible for:

- Ensuring that this policy is comprehensive, clear and current.
- Ensuring that this policy is communicated to the controller of each affiliate through communication tools as found appropriate, as well as posting on Toronto Hydro Intranet.

1.3.3 The Controller of each affiliate, or his delegate, is responsible for:

- Ensuring that this policy is communicated to the departments and staff that are impacted (mostly, the IT Department), and providing support for the application of the policy at the business unit level.
- Ensuring that this policy is adhered to, through the capital budgeting review process when the proposed expenditures are reviewed for compliance with the capital versus operating criteria.
- Immediately communicating any exceptions or violations of this policy to the Corporate Controller for assessment of the impact to the financial statements.
- Communicating any proposed policy changes to the Corporate Controller for approval.

1.3.4. All staff impacted by this policy is required to adhere to this policy.

1.4 Definitions

1.4.1 Software is a computer program, written in machine-readable language, that controls the operations hardware or that enables users to perform certain tasks on the computer. The two principle categories of software are systems and applications programs.

1.4.2 Systems software, which controls the computer system, or hardware, includes the operating system. The operating system manages a computer's internal functions: controls input, output and storage and, in general, handles its interactions with applications programs. Applications software enables users to accomplish particular tasks.

1.5 References

1.5.1 CICA Handbook ("CICA HB") Section 3062 – Goodwill and Other Intangibles
1.5.2 CICA HB Section 3061 – Property, Plant and Equipment
1.5.2 CICA HB Section 3450 – Research and Development Costs
1.5.3 OEB Accounting Procedures Handbook for Electric Distribution Utilities ("APHandbook")

1.6 Accounting Policy

1.6.1 Governing Principle

Expenditures are capitalized to provide an equitable allocation of cost among existing and future customers. As assets are expected to provide future benefits, expenditures incurred for the acquisition, construction or development of assets should be capitalized and allocated over the estimated useful lives of the associated assets in the form of amortization.1

Accordingly, expenditures related to the acquisition or betterment of an asset, where future benefits are reasonably assured 2, should be capitalized as an asset and all other expenditures should be expensed in the accounting period incurred.

1.6.2 General concepts

i. Computer software developed or obtained for internal use, where future benefits are reasonably assured, is an intangible capital asset 3.
ii. Capital assets are expenditures for which the future benefits to the company extend over one or more accounting periods / years.

1 Per the APHandbook Article 410 "Capital Assets".
2 CICA HB Section 3062.07
3 "Property, plant and equipment" and "intangible assets" are referred to collectively as capital assets.

iii. Expenses, frequently referred to as operating expenses, are expenditures where the benefits do not extend beyond the current accounting period / year.
iv. Future benefit involves a capacity of the asset to contribute directly or indirectly to future net cash flows.

1.6.3 System software

System software should be capitalized since it is an integral component to the operation of the hardware.

1.6.4 Application software

Application software related to specific software systems should be capitalized, e.g. Customer Information System, Ellipse, LDC Settlement, EARMS, GEAR, etc.

1.6.5 Betterments (capital) versus expense (operating)

Expenditures that meet the definition of betterment should be capitalized.

i. Betterments are costs incurred to "enhance" the service potential of "existing" computer software. Service potential may be enhanced when there is an increase in the previous assessed output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved.
ii. Expenses are defined as the costs incurred in the "maintenance" of the service potential of the computer software (Intangible asset). Expenses are costs incurred more or less on a continuous basis to keep the software at its normal operation level, **but do not add materially to the use value of the software**, nor prolong its life appreciably, e.g. software maintenance contracts.

1.6.6 Software costs to be capitalized:

Cost:

Cost is the amount of consideration given up to acquire, construct, develop, or better an intangible asset. It includes all cost directly attributable to the acquisition, construction, development, or betterment of the asset including installing it at the location and in the condition necessary for its intended use.[4]

In-house software development:

Capitalization of in-house software development costs should occur once the technical feasibility of the software has been established. The costs to be recorded include both direct development costs and overhead costs directly attributable to development activity.[5]

4 CICA HB Section 3061.05
5 CICA HB Section 3062.07

The costs to be capitalized are:

i. Program development costs;
ii. Coding;
iii. Testing;
iv. Production of training and system documentation; and
v. Training costs for the implementation team, incurred during the software implementation period. For this purpose, the implementation period would be complete when the software is put in service.

The costs to be expensed are planning, conceptual design, establishing feasibility, and user training and other on-going support costs.

Definition of technical feasibility: Where the feasibility of an in-house software development has been established; and management approval to proceed has been obtained; and an RFP has been issued, if purchased software.

Purchased software

The costs to be capitalized are:

i. Direct costs associated with the purchase price of the software, e.g. training costs for the implementation team, incurred during the software implementation period. Costs of associated equipment would be capitalized as property, plant and equipment asset within computer hardware.
ii. Costs of user customization, installation and testing to make the software operational.

Other costs to be expensed during the life of the software

i. Software system maintenance;
ii. User training and other on-going support costs; and
iii. Adaptation of an existing capability to a particular requirement or customer's need as part of a continuing commercial activity (modifications), after the system is in the production environment.

1.7 Amortization

Consistent with the CICA HB, the APHandbook does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, and the estimated useful lives or amortization rates. Instead, it is expected that in the absence of an objective study to support changes to the current methods, lives or rates, utilities will continue to use methods, lives or rates consistent with past practice. Note that the OEB may review the selected amortization methods, estimated useful lives and amortization rates, as it considers necessary.

i. Amortization of software costs is usually done over a three to five year period. Five years in some cases is considered the upper limit because this is generally the same asset life for the

associated hardware. The decision on the period to choose is dependent upon management's assessment of the useful service life, a matter of professional judgement in each case. The useful life of the Banner CIS system was determined to be seven years.

ii. The company should recognize amortization in a rational and systematic manner appropriate to the nature of the software and its intended use, to match costs to the related benefits.

iii. The amortization method and estimates of the life of a capital asset should be reviewed on a regular basis.

1.8 Materiality and minimum threshold dollar amounts for capitalization

For practical purposes, once an expenditure has been determined as capital in nature, only those expenditures that exceed the threshold dollar amount of $2,000 should be treated as capital. Expenditures below this threshold amount should be treated as an immaterial expense in the period incurred.

1.9 OEB Uniform System of Accounts ["USoA"]

The APHandbook defines "Computer software", USoA account #1925, as follows:
"This account shall include the cost of developed and purchased computer operating and application software that is material in amount.
Example items:

i. Accounting packages
ii. Customer Information System
iii. Groupware packages, e.g. e-mail, scheduling and conferencing programs, etc., including gateways
iv. Database management system packages
v. Software development tools
vi. Primary development tools, e.g. PowerBuilder"

DEPRECIATION EXPENSES

Table 1: Years Ending December 31 ($ Millions)

	2006 Approved	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Distribution Plant	105.2	103.3	105.0	110.2	116.4	123.9
Information Technology	11.2	11.0	13.5	18.1	21.0	24.6
Smart Meters	-	-	-	10.2	8.3	10.4
Equipment, Vehicles, and Other	10.5	10.3	13.9	15.2	15.2	15.5
Total	126.9	124.6	132.4	153.7	160.9	174.4

REPORT ON LEAD LAG STUDY AND WORKING CAPITAL RESULTS USING 2005 EXPENSE LEVELS

Presented to:

Toronto Hydro Electric System Limited

December 4, 2006

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I. INTRODUCTION

In 2006, the Ontario Energy Board ("OEB") issued a directive to Toronto Hydro Electric System Limited ("THESL" or the "Company") requesting that the Company conduct a study of its lead/lag methodology to support its future working capital submissions before the OEB[1]. In response to the directive, the Company retained Navigant Consulting, Inc. ("NCI") to perform a lead/lag study using the most recent data available and to derive THESL's working capital requirements for the historical 2005 "test" year. The purpose of this report is to provide the results of the lead-lag study and to determine the working capital requirements of the Company's distribution business.

I.A. Working Capital and Lead/Lag Studies

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility. The determination of working capital generally relies on a lead/lag study.

A lead/lag study analyzes the time elapsed between the date customers receive service and the date that such customers' payments are available to the Company (or "lag") together with the time during which the Company receives goods and services but pays for them at a later date (or "lead"). "Leads" and "Lags" are both measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of the Company's rate base.

[1] EB-2005-0421, Decision With Reasons, Issued April 12, 2006

Performing a lead/lag study requires two key undertakings: a) developing an understanding of how the regulated business works in terms of collections and payment policies and procedures; and b) development of a representative data set that reflects the implementation of such policies and procedures in terms of the timing of payments received (sent) at any given point in time.

To develop an understanding of THESL's operations, interviews with personnel within the regulated utility's Accounts Payable, Customer Service, Human Resources, Payroll, and Tax Departments were conducted. As in prior instances where NCI has conducted lead/lag studies, some key issues that were addressed during the course of the interviews included:

- The nature of buyers (sellers) within the business;
- The nature of the product or service, i.e., what is being sold (or bought), or, if a service was being provided;
- The time period over which the service was provided;
- Payment Terms, i.e., whether driven by government mandate, industry norms, or by company policy and the degree of flexibility within the terms for payment;
- Actual payment dates and amounts;
- Method of payment for such products (or services), e.g., cash, check, electronic;
- Expectation of changes (if any) to the Company's collections and payment policies or procedures going-forward.[2]

Operational data was obtained from THESL's Accounts Payable, Customer Service, Human Resource, Payroll, and Tax Systems. Once the data had been gathered, sampling and data validation was performed to the extent necessary and appropriate. Data validation generally took the form of comparing an actual invoice or a bill with data from the Company's systems to ensure accuracy. Except where otherwise noted,

[2] Activity over a given twelve month period is used to analyze the timing of payments and receipts unless interviews with Company personnel reveal that there are known changes to existing policies or procedures going forward. Where such changes are known, they have been incorporated into the derivation of the appropriate leads, lags, and net lags.

the lead-lag study focused on activities within THESL for the twelve months ended August 31, 2006.

I.B Organization of the Report

Section II of this report discusses the lags associated with the Company's collections of revenues. Included in Section II is a description of the sources of revenues and how they were treated for the purposes of deriving an overall revenue lag for the Company's distribution operations.

Section III presents a description of the various expenses and their attendant lead times. Included in the discussion on expense leads is the lead-time on OM&A costs, interest on long-term debt, Payments in Lieu of Taxes (such as Capital, Income, and Large Corporation Taxes), and the Goods and Services Tax (or "GST"). The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section IV sets forth a summary of THESL's working capital requirements for its distribution operations using operating expense data for the historical 2005 year.

II. REVENUE LAGS

A utility providing service to its customers generally derives its revenue from the services provided to its customers. Revenue lags represent the number of days from the date services are rendered by the Company until the date payments are received from the customers and such funds are available to the Company. Based on a review of the Company's accounting records, NCI has determined that the majority of THESL's revenues originate from two sources:

1. Residential Class, various General Service Classes, and Large User Class customers, hereafter referred to as "Bundled service ratepayers";
2. Other (miscellaneous) sources including (but not limited to) retailers, connection charges, transformer rentals and customer related jobs.

When both sources of revenues are considered together, the weighted average revenue lag time is 71.53 days. Table II-1 shows the amount of these revenues in 2005, the revenue lags associated with each revenue source, and the weighted average of all revenue sources.

Table II-1

THESL Revenue Lag

Source of Revenues	Revenue Lag (Days)	2005 Amounts (Mil $s)	Weighting Factor	Weighted Revenue Lag
Revenues from Bundled Service Ratepayers	71.76	2,687	99.17%	71.16
Revenues from Other Sources	44.66	22	0.83%	0.37
Total		2,709	100.00%	71.53

II-A. Revenues from Bundled Service Ratepayers

As shown in Table II-1, revenues from bundled service ratepayers represented 99.17% of total revenues realized by the Company during 2005. The lag time associated with the realization of such revenues was 71.76 days.

The lag associated with the Company's provision of service to its bundled service ratepayers typically consists of four components: a) Service lag; b) Billing lag; c) Collections lag; and, d) the lag associated with the Company's payment processing lag (including bank float). The contribution of each component to the overall revenue lag is shown in Table II-2, below.

Table II-2

Revenue Lag from Bundled Service Ratepayers (Days)

Revenue Lag Component	Days
Service Lag:	27.10
Billing Lag:	16.17
Collections Lag:	27.06
Payment Processing & Bank Float Lag:	1.43
Total	71.76

A discussion of each of the four components follows.

II.A.1 Service Lag

The Service Lag covers the period between the time the Company provides service and the time customers' meters are read. Interviews with the Company's customer service personnel revealed that the Company's customers have their meters read on a monthly or bi-monthly basis. Based on this information and using data from the Company's Customer Information System ("CIS") regarding the number of customers that receive monthly and bi-monthly service respectively, NCI determined that the average service lag was 27.10 days.

II.A.2 Billing Lag

The billing lag refers to the average number of days from the date the meter is read until the customer is billed. Based on the Company's monthly scheduled meter read and bill dates, NCI determined an average billing lag of 16.17 days for the twelve months ended August 31, 2006.[3]

II.A.3 Collections Lag

The collections lag refers to the average amount of time from the date the Company mails a bill to the date that THESL receives the customer's payment. For the purpose of this lead/lag study, this information was derived from an aging of accounts receivables report that showed the amount outstanding by aging day interval. Using data for the twelve-month period ended August 31, 2006, an average collections lag time of 27.06 days was derived.

II.A.4 Payment Processing and Bank Float

Based on interviews with the Company's Customer Service Department and the Company's Treasury operations, NCI determined that customer payments to the Company were typically in the form of pre-authorized payments, checks (lockbox), payments via the telephone, payments directly to financial institutions for credit to the Company's bank account, electronic payments (internet payments or direct debit payments), or payments via credit card. Using data on actual payments made and processed for the twelve-month period ended August 31, 2006, NCI determined that the weighted average lead-time associated with payment processing and bank float was 1.43 days.

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[3] This average billing lag includes the time period associated with the Company's receipt of billing data from the Ontario Independent Electric System Operator ("IESO") in order to bill its customers.

II.C. Revenues from Other Sources

Revenues from other sources represent 0.83% of the Company's total collections during 2005. The timing of receipts of such other revenues from customers depends on the Company's billing, collections, and payment processing and bank float operations. Thus, a lag time of 44.66 days was used in the derivation of the Company's overall revenue lag time as shown on Table II-1.

III. EXPENSE LEADS (LAGS)

As mentioned at the outset, a lead/lag study considers both the lag time associated with the collection of revenues from customers as well as the lead (or lag) time associated with the payment for goods and services provided to the Company by its vendors. For the purpose of this lead/lag study, the following four broad categories of expenses were considered in order to estimate the overall cash working capital requirement of the Company:

1. Cost of power;
2. Operations, Maintenance, and Administrative ("OM&A") expenses[4];
3. Interest on Long Term debt; and
4. Taxes.

Each of these categories and the associated expense lead (or lag) times are discussed below.

III.A Cost of Power

The Company purchases all of its power supply requirements from Ontario's Independent Electric System Operator (the "IESO"). Based on actual billings and the Company's payments to (or receipts from) the IESO during the twelve month period ended August 31, 2006, a weighted expense lead time of 32.61 days was derived for the cost of power.

This weighted expense lead-time includes an average service lead-time of 15.21 days since the IESO provides service to the Company on a monthly basis. The

[4] The categories included within OM&A expenses are generally consistent with those defined within the Ontario Energy Board's Distribution rates Handbook.

derivation of the expense lead-time associated with the cost of power is shown in Table III-1[5].

Table III-1

Derivation of the Expense Lead Time for Cost of Power

Service Begin	Service End	Service Lead Time	Monthly Payment Amounts	Payment Date	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time
9/1/2005	09/30/2005	15.00	200,974,640	10/19/2005	19.00	34.00	10.02%	3.41
10/1/2005	10/31/2005	15.50	184,360,107	11/17/2005	17.00	32.50	9.19%	2.99
11/1/2005	11/30/2005	15.00	161,372,179	12/16/2005	16.00	31.00	8.05%	2.49
12/1/2005	12/31/2005	15.50	202,696,412	1/18/2006	18.00	33.50	10.11%	3.39
1/1/2006	01/31/2006	15.50	162,630,421	2/16/2006	16.00	31.50	8.11%	2.55
2/1/2006	02/28/2006	14.00	156,059,276	3/16/2006	16.00	30.00	7.78%	2.33
3/1/2006	03/31/2006	15.50	86,324,877	4/20/2006	20.00	35.50	4.30%	1.53
4/1/2006	04/30/2006	15.00	138,929,508	5/16/2006	16.00	31.00	6.93%	2.15
5/1/2006	05/31/2006	15.50	169,178,427	6/16/2006	16.00	31.50	8.43%	2.66
6/1/2006	06/30/2006	15.00	165,500,488	7/19/2006	19.00	34.00	8.25%	2.81
7/1/2006	07/31/2006	15.50	184,853,295	8/17/2006	17.00	32.50	9.22%	3.00
8/1/2006	08/31/2006	15.50	192,839,849	9/19/2006	19.00	34.50	9.61%	3.32
			2,005,719,479				100.00%	32.61

[5] By ignoring the IESO creditworthiness requirements when computing the expense lead time associated with the cost of power, the Company has been conservative in estimating the working capital requirement associated with the cost of power. As it stands today, should the Company be downgraded to a BBB rating category, an additional $80 million in letters of credit may need to be posted with the IESO. More importantly, and from a working capital perspective, THESL is subject to margin calls from the IESO. If THESL's "actual exposure" (i.e., the total amount owed to the IESO) crosses a pre-determined threshold, the IESO can and does issue actual margin calls; all margin calls must be paid in cash within 2 business days of the margin call, and must be enough to reduce THESL's actual exposure down to 35% of its "maximum exposure". Margin calls posted are used as offsets against the next IESO invoice. THESL is currently in discussions with the IESO to try and change this with a view to making this less onerous. Should these discussions prove unsuccessful, THESL may have to reflect the IESO practices and recompute the expense lead time (and accompanying working capital requirements) associated with the cost of power.

III.B OM&A Expenses

The next category of expenses considered in the lead/lag study was OM&A expenses. Included within this category were the following types of expenses:

1. Payroll and Benefits;
2. Expenses associated with Consulting and Contract Staff;
3. Lease Expenses;
4. Provincial and Local property taxes; and
5. Miscellaneous Operations and Maintenance expenses.

The expense lead times associated with each type of OM&A expense are discussed below.

III.B.1 Payroll and Benefits

The category "Payroll and Benefits" consists of a number of expense-related items. A summary of the items considered, their individual expense lead times, their corresponding weighting factors, and the overall weighted expense lead time is shown in Table III-2 below.

Table III-2

Payroll and Benefits

	Amounts Twelve Months ended August 31, 2006	Lead (Lag) Days	Weighting Factor	Weighted Lead
Net Payroll - Actives	$76,577,494	11.50	52.30%	6.01
Withholdings - Actives	33,829,038	20.82	23.10%	4.81
Pensions	18,156,050	45.28	12.40%	5.61
Employer Health Tax	2,139,600	30.21	1.46%	0.44
Workers Safety Improvement Board Payments (WSIB)	955,096	45.24	0.65%	0.30
Group Medical and Dental	11,334,337	0.50	7.74%	0.04
Group Life	2,155,568	35.20	1.47%	0.52
Long Term Disability (LTD)	1,176,620	35.19	0.80%	0.28
Accidental Death and Dismemberment (ADD)	24,544	35.21	0.02%	0.01
Employee Assistance Program (EAP)	72,447	35.22	0.05%	0.02
Total	$146,420,793		100.00%	18.04

Each item in Table III-2 is discussed below.

III.B.1.1 Payroll and Payroll Related Withholdings

Based on interviews with the Company's payroll department, NCI determined that:

- All active THESL employees are paid bi-weekly on the same cycle. Payroll administration is outsourced and ADP is the payroll administrator. ADP has access to net payroll funds a day in advance of payday.
- Payroll related taxes and withholdings, on the other hand, are remitted to the respective authorities by THESL.
- All payments are via electronic funds transfer.

Based on this information and taking into account actual pay dates and amounts as well as withholding remittance dates and amounts, an expense lead time of 11.5 days

was estimated for active employee payroll and 20.82 days for withholdings associated with active payroll.

III.B.1.2 Pensions

In accordance with the requirements of its pension fund administrator (The Ontario Municipal Employee Retirement System or "OMERS"), the Company is required to make contributions to OMERS on the last day of the month following the month of service. Using actual payment dates and amounts remitted and using a 15.21 day service lead time (the mid-point of the month for which a contribution is due), an overall expense lead time of 45.28 days was derived.

III.B.1.3 Employer Health Tax ("EHT")

Pursuant to the Income Tax Act, the Company is required to make monthly installment payments associated with the EHT around the middle of the month following the month of service. Taking into account actual remittances made by the Company, the remittance dates, as well as the service periods covered by those remittances, the weighted expense lead-time was calculated to be 30.21 days.

III.B.1.4 WSIB Payments

The Workplace Safety Insurance Board ("WSIB") oversees Ontario's workplace safety education and training system, provides disability benefits, monitors the quality of health care, and assists in early and safe return to work. The WSIB premium covers workers on a Corporation's payroll, either working full or part time under a contract of service or as an apprentice. Based upon WSIB coverage periods, and actual payment amounts and dates during the twelve-month period ended August 31, 2006, an expense lead-time of 45.24 days was derived.

III.B.1.5 Group Medical and Dental

During 2005-06, the Company's Health and Dental program was administered by Manulife which charges an administrative fee for services rendered and is reimbursed for claims. The Company paid the administrator daily for both the administration and claims related costs incurred by Manulife. Taking into account actual payments made by the Company, an expense lead-time of 0.5 days was estimated.

III.B.1.6 Group Life, Accidental Death and Dismemberment ("ADD"), Long Term Disability ("LTD"), and Employee Assistance Programs ("EAP")

During 2005-06, the Company's programs were administered by MEARIE, RBC Insurance, SunLife, and Warren Sheppell, which charges premiums or administrative fee for services rendered. Life Insurance premiums and administrative fees for the Company's LTD, ADD, and EAP programs are paid monthly by check typically around the 15th of the month following the month of service. Taking into account actual payments made by the Company during 2005, expense lead time estimates for: a) Group Life is 35.20 days, b) LTD is 35.19 days, c) ADD is 35.21 days, and d) EAP is 35.22 days.

III.B.2 Consulting and Contract Staff

The second type of expense which falls under OM&A expenses are those associated with Consulting and Contract Staff. Using data on invoices from vendors of services provided to the Company, NCI determined that the average expense lead-time associated with payments for consulting and contract staff was 54.78 days. The invoices included a broad spectrum of services ranging from communications and training, contract employee services, building maintenance, and architectural and other consulting related services.

III.B.3 Leases

The third type of expense included under the OM&A umbrella are payments made by the Company for operating leases. The Company leases office space as well as space for its communication antennas. Based on actual payments made for the leases for the twelve months ended August 31, 2006, a weighted expense lead-time of negative 14.71 days was determined.

III.B.4 Property Taxes

The Company makes two forms of property tax payments: a) Payments to the City of Toronto, b) PILS property taxes to the Province of Ontario. Property Taxes were paid to the City of Toronto in six installments during the current year for the current year. The first three payments were estimated and trued up in the second set of three payments. Payments were made by wire transfer. Based on actual payments made during 2005, a weighted expense lead-time of negative 28.09 days was determined.

PILS property taxes were paid to the Province of Ontario in two installments. The first was an estimate and the second consisted of a true up as well as the second payment amount. PILS Property Taxes were paid in the current year for the current year and were paid by wire transfer. Based on actual payments made during 2005, a weighted expense lead-time of 12.67 days was determined.

III.B.5 Miscellaneous Operations and Maintenance Expenses

Using invoices for routine goods and services provided to the Company, NCI determined a weighted average expense lead-time of 40.08 days for miscellaneous operations and maintenance related expenses. NCI's analysis took into account transactions that occurred during 2005 and, where services were provided to the Company, used the actual service periods shown on vendor invoices.

III.C. Interest on Long Term Debt

The Company has two outstanding long-term debt instruments; both of which were payable to THESL's holding company (Toronto Hydro Corporation or "THC"):

- $980 million at 5 percent. Interest was payable quarterly by THESL to THC on the last day of March, June, September, and December. Payments were made by wire transfer.
- $180 million at 6.16 percent. Interest was due semi-annually on May 7th and November 7th. Payments were made by wire transfer.

Taking this information into account, an expense lead-time of 43.23 days was estimated.

III.D. Taxes

Both income and non-income taxes, as well as pass-through taxes, must be considered in a lead/lag study when deriving working capital requirements. The categories of taxes that were considered in this study were: 1) Payments in Lieu (PIL) of Taxes including the Ontario Capital Tax and the Corporate Income and Large Corporation Tax, 2) the Debt Retirement Charge, and 3) the Goods and Services Tax ("GST").

III.D.1 Payments in Lieu of Taxes (PILs)

The Company paid its current year PILS obligations (Capital, Corporate Income, and Large Corporation Tax) to the province of Ontario in monthly installments and made a true up payment in or around February of the following year. Thus, the Company was pre-paying a portion of its annual tax obligation and post-paying the balance. Taking this information into account and using actual payment dates and amounts, an expense lead-time of 37.95 days (dollar-weighted by amount paid by month) was derived.

III.D.2 Debt Retirement Charge ("DRC")

DRC collections by the Company were used to retire the former Ontario Hydro stranded debt. Annual DRC amounts were paid in monthly installments to the Ontario Electric Finance Corporation (OEFC). Such payments are generally made on the 18th of every month for the month prior and are calculated based on prior month billings. Payments were made by wire transfer. Based on actual DRC payments made in 2005, a weighted expense lead-time of 33.2 days was determined.

III.D.3 Goods and Services Tax

The GST is imposed by the Federal Government and is levied at a flat rate of 6 percent. The following categories of GST were considered in this study:

1. Retail Revenues
2. Cost of Power
3. Consulting and Contract Staff
4. Lease Payments
5. Miscellaneous Operations and Maintenance Expenses

III.D.3.1 GST - Retail Revenues

The Company is obligated to collect GST from its customers and remit such collections to the Federal Government. Remittances were generally due on the last day of the month following the month in which a customer is billed for GST. Based on this information, a GST lead-time of negative 18.49 days was determined. The lead-time is shown as negative as such GST amounts which the Company was required to remit represent a source of working capital to the Company.

III.D.3.2 GST – Cost of Power

The Company is owed GST on amounts that it pays on power supplies from the IESO. Similar to retail revenues, a reimbursement generally occurs at the end of the month following the date of payment (or receipt) of funds from the IESO. Using actual dates of payments/receipts, an average expense lead-time of 43.58 days was determined and used in the derivation of the Company's cash working capital requirement.

III.D.3.3 GST – Consulting and Contract Staff

Reimbursements were made on the last day of the month following the dates on which the Company made payments on account of its retaining consulting and contract staff. Taking this information into account and using actual payment dates, an expense lead-time of 44.64 days was derived and used in the determination of the Company's cash working capital requirements.

III.D.3.4 GST – Lease Payments

Reimbursements were made on the last day of the month following the dates on which the Company made lease payments. Taking this information into account and using actual payment dates, an expense lead-time of 46.68 days was derived and used in the determination of the Company's cash working capital requirements.

III.D.3.5 GST – Miscellaneous Operations and Maintenance Expenses

As with other categories of GST, using actual payment dates on miscellaneous operations and maintenance expenses, an expense lead-time of 47.16 days was determined.

IV. THESL'S WORKING CAPITAL REQUIREMENTS

This section presents the derivation of the Company's working capital requirements using the revenue lags and expense leads discussed in Sections II and III, respectively. Table IV-1 shows the overall derivation of the Company's cash working capital requirement.[6] Footnotes 1, 2, and 3 to Table IV-1 are provided in support of the information shown in Table IV-1. As shown in Table IV-1, the net cash working capital requirement using 2005 expense levels is $298 million or approximately 12.45 percent of OM&A expenses and the cost of power. As would be expected, the cost of power is the most significant contributor to the Company's net cash working capital requirement followed by OM&A expenses. What drives the magnitude of the requirements is the significance of the net lag (i.e., revenue lag minus the expense lead time) for both these items.

[6] The dollars provided in Column E of Table IV-1, were provided by (and will be addressed by) the Company. NCI has not reviewed, nor have we expressed an opinion as to the accuracy of the figures.

Table IV-1

Calculation of THESL Working Capital Requirement

(All data in Millions $s except where otherwise noted)[7]

	Expense Item Description	Revenue Lag (Days)	Expense lead (Days)	Net Lag (Lead) Days	Working Capital Factor	Expenses at Present Rates	Working Capital Requirement
		(A)	(B)	(C)	(D)	(E)	(F)
1	Cost of Power	71.53	32.61	38.92	10.63%	2,224	236
2	OM&A Expenses	71.53	19.86	51.67	14.12%	167	24
3	Interest on Long term debt	71.53	43.23	28.30	7.73%	81	6
4	Payments in Lieu of Taxes	71.53	37.95	33.58	9.18%	61	6
5	Debt Retirement Charge	71.53	33.20	38.33	10.47%	159	17
6	Sub-Total					2,692	289
7	GST[8]					19	9
8	TOTAL (including GST)					2,711	298
9	**Working Capital as a % of OM&A including Cost of Power**						**12.45%**

[7] Strictly speaking, the Debt Retirement Charge and GST are not "expenses", but rather are "flow through expenditures".

[8] See Footnote 1 for calculation.

NAVIGANT CONSULTING

Footnotes 1, 2, and 3 to Table IV-1

FOOTNOTE 1: GST CALCULATION					
	GST CATEGORY	**2005 Expenses (Mil $s)**	**6% GST**	**Net Lead (lag) Days**	**GST Benefit (Cost)**
		(A)	(B)	(C)	(D)
1	Revenue	2,709	163	(18.49)	(8)
2	Cost of power	2,224	(133)	43.58	16
3	OM&A Expenses	167	(10)	46.93	1
4	TOTAL		22		9

FOOTNOTE 2: OM&A CALCULATION					
OM&A CATEGORY		**Amounts for the 12 months ended 8/31/06 ($000s)**	**Weighting Factor**	**Expense Lag Time**	**Weighted Expense Lead Time**
		(A)	(B)	(C)	(D)
1	Payroll and benefit costs	146,421	79.93%	18.04	14.42
2	Consulting and contract staff	2,586	1.41%	54.78	0.77
3	Lease Payments	357	0.20%	(14.71)	(0.03)
4	Property taxes - Province	539	0.29%	12.67	0.04
5	Property taxes - City	7,052	3.85%	(28.09)	(1.08)
6	Miscellaneous O&M	26,234	14.32%	40.08	5.74
7	TOTAL	183,188	100.00%		19.86

FOOTNOTE 3: CALCULATION OF GST LEAD TIME ON OM&A					
GST CATEGORY		**Amounts for the 12 months ended 8/31/06 ($000s)**	**Weighting Factor**	**GST Expense Lead Time**	**Weighted Expense Lead Time**
		(A)	(B)	(C)	(D)
1	Consulting and contract staff	2,586	8.9%	44.64	3.96
2	Lease Payments	357	1.2%	46.68	0.57
3	Miscellaneous O&M	26,234	89.9%	47.16	42.40
	TOTAL	**29,177**	**100.0%**		**46.93**

2008 Working Capital Allowance ($ Millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		2008 Expenses	**Working Capital Factor**	**GST Working Capital (2)**	**Working Capital Requirement (1)**
1	Cost of Power	$1,922.6	10.63%		$204.4
2	OM&A	$196.0	14.12%		$27.7
3	Interest on long term debt	$64.3	7.73%		$5.0
4	Income and capital tax	$28.7	9.18%		$2.6
5	DRC	$180.4	10.47%		$18.9
6	Sub-Total Working Requirement				$258.5
	GST at 6%		Net Lag Days		
	Revenue	$2,448.6	-18.5	-7.4	
	Cost of power	$1,922.6	43.6	13.8	
	OM&A Expenses	$196.0	46.9	1.5	
7	GST Working Capital Requirement				$7.8
8	**Total Working Capital**				**$266.4**

Notes:
(1) Expenses x Working Capital Factor
(2) Expenses x 6% GST x Net Lag Days / 365

2009 Working Capital Allowance ($ Millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		2009 Expenses	**Working Capital Factor**	**GST Working Capital (2)**	**Working Capital Requirement (1)**
1	Cost of Power	$1,923.7	10.63%		$204.5
2	OM&A	$206.5	14.12%		$29.2
3	Interest on long term debt	$67.0	7.73%		$5.2
4	Income and capital tax	$27.7	9.18%		$2.5
5	DRC	$180.4	10.47%		$18.9
6	Sub-Total Working Requirement				$260.2
	GST at 6%		Net Lag Days		
	Revenue	$2,486.6	-18.5	-7.6	
	Cost of power	$1,923.7	43.6	13.8	
	OM&A Expenses	$206.5	46.9	1.6	
7	GST Working Capital Requirement				$7.8
8	**Total Working Capital**				**$268.1**

Notes:
(1) Expenses x Working Capital Factor
(2) Expenses x 6% GST x Net Lag Days / 365

2010 Working Capital Allowance ($ Millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		2010 Expenses	**Working Capital Factor**	**GST Working Capital (2)**	**Working Capital Requirement (1)**
1	Cost of Power	$1,925.6	10.63%		$204.7
2	OM&A	$213.8	14.12%		$30.2
3	Interest on long term debt	$71.8	7.73%		$5.6
4	Income and capital tax	$26.6	9.18%		$2.4
5	DRC	$180.5	10.47%		$18.9
6	Sub-Total Working Requirement	$2,418.4			$261.8
	GST at 6%		Net Lag Days		
	Revenue	$2,511.9	-18.5	-7.6	
	Cost of power	$1,925.6	43.6	13.8	
	OM&A Expenses	$213.8	46.9	1.6	
7	GST Working Capital Requirement				$7.8
8	**Total Working Capital**				**$269.6**

Notes:
(1) Expenses x Working Capital Factor
(2) Expenses x 6% GST x Net Lag Days / 365

WORKING CAPITAL

The working capital requirement for THESL is based on the following factors:

- the forecast of OM&A;
- the retail cost of power;
- capital and income taxes, Goods and Services Tax, Debt Retirement Charges, and interest on long term debt; and
- the net lead/lag days.

In its RP-2005-0020 / EB-2005-0421 Decision with Reasons, the OEB stated that it expected THESL to develop a lead/lag study in preparation for its next rates hearing. THESL retained Navigant Consulting Inc. to undertake this study, which has been filed at Exhibit D1, Tab 15, Schedule 1. The provision of working capital for the bridge and test years incorporates the methodology stemming from this study.

Table 1 below includes the working capital for the historic, bridge and test years.

Table 1: Working Capital Allowance ($ Millions)

	2006 Approved	2006 Actual	2007 Bridge	2008 Test	2009 Test	2010 Test
Working Capital	307.6	293.0	262.4	266.4	268.1	269.6

DEFERRED INCOME TAXES

THESL is exempt from tax under the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)*, if not less than 90 percent of its capital is owned by the City of Toronto (the "City") and not more than 10 percent of its income is derived from activities carried on outside the municipal geographical boundaries of the City.

THESL is a "municipal electricity utility" for purposes of the PILs regime contained in the *Electricity Act, 1998*. The PILs regime came into effect on October 1, 2001, at which time THESL was deemed to have commenced a new taxation year for purposes of determining the respective liabilities for PILs. Accordingly, THESL was deemed to have disposed of its assets at their then fair market value and to have re-acquired such assets at the same amount. The differences between the financial statement carrying value and tax bases of assets and liabilities were accounted for by THESL under the taxes payable method of accounting applied in accordance with recommendations of the Canadian Institute of Chartered Accountants and the OEB.

Under the taxes payable method, no provisions are made for future income taxes (deferred taxes) as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for account purposes.

CAPITAL CONTRIBUTIONS TO HYDRO ONE NETWORKS INC. ("HONI")

INTRODUCTION AND SUMMARY

Toronto Hydro-Electric System Limited ("THESL") will be required to make capital contributions to HONI during the 2008, 2009, and 2010 test years. The contributions amount to a total of $35M over the three test years as shown in Table 1 below:

COSTS[1]

Table 1: THESL Capital Contributions to HONI ($ Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test	Total
Leaside -Birch TS	-	5.0	10.0	20.0	35.0

LEASIDE-BIRCH TS

The Leaside-Birch transmission reinforcement is expected to be completed in 2010. HONI has submitted information to THESL indicating that a $5M capital contribution will be required in 2008 and a further $10M capital contribution will be required in 2009 for project design and procurement of equipment. Additionally, capital contributions for construction of $20M will be required in 2010.

A joint HONI and THESL study ("Joint Study") on the adequacy of the supply to the City of Toronto, identified the need to reinforce the 115 kV transmission network between Leaside TS and Wiltshire TS to provide relief for the existing insufficient capacity condition under the first contingency. Under first contingency conditions (i.e. one element of the transmission system out of service), there is insufficient capacity to

[1] Costs are preliminary and subject to engineering and HONI calculation of capital contribution on final design

supply the load demand at the Terminal Stations ("TS") serviced by these circuits (Bridgman TS and Dufferin TS). In addition, these circuits also provide load transfer capability between the Leaside TS and Manby TS 115 kV 230/115 kV autotransformer stations.

The Joint Study recommended reinforcement by building a new transmission circuit from Leaside TS to Birch Junction on a priority basis. This work will reduce the risk of customer interruptions and provide improved reliability for customers in the areas served by Bridgman TS and Dufferin TS. If not undertaken, customers from Bridgman TS and Dufferin TS will be on rotating outages if one element of the transmission circuits was to be out of service during the summer, the period of peak demand. These outages could last for several days, severely disrupting the activities of those who live and work in the affected areas.

THESL INVESTMENT JUSTIFICATION SUMMARY
LEASIDE-BIRCH JUNCTION TRANSMISSION REINFORCEMENT

Description: Leaside-Birch Junction Transmission Reinforcement
In Service: Mid 2010

Need

- To eliminate the possibility of load restrictions on customers under the first contingency of outage of one of the three 115 kV circuits on the Leaside-Bridgman corridor (i.e., one element of the transmission system out of service)
- To provide transmission capacity for load growth at Bridgman TS so as to support downtown stations
- To provide for backup capacity to improve reliable supply for the Manby Sector during low-probability high-impact contingency situations

Investment Summary

A joint HONI and THESL study on the adequacy of the supply to the City of Toronto has identified the need to reinforce the 115 kV transmission network between Leaside TS and Wiltshire TS.

The existing facilities between Leaside TS and Wiltshire TS consist of three 115kV circuits L13W, L14W and L15W and their capability is sufficient to supply 272 MW of load. These circuits supply Bridgman TS and Dufferin TS and they also provide load transfer capability between the Leaside TS and Manby TS 115 kV 230/115 kV autotransformer stations. The 2005 coincident summer peak load for Bridgman TS and Dufferin TS was 288 MW. Therefore, loss of either the L13W or the L15W circuit will cause load flow on the remaining circuits to exceed their capacity ratings. As a result,

transmission reinforcement is required to provide relief for the existing insufficient capacity condition under the first contingency.

THESL, independent of the Joint Study, examined distribution system level solutions to the transmission constraint. These solutions consisted of load transfers away from the affected stations to stations not on the constrained transmission circuits. THESL determined that the size of the most feasible distribution load transfer away from Bridgman and Dufferin TS was 42.5 MVA. This solution would take six years to implement at an estimated cost of $21 million. By the time the load transfer would be completed, the Leaside-Wiltshire corridor would still have insufficient capacity under a first contingency. Accordingly, the most feasible distribution-only solution does not eliminate the overloading and therefore does not postpone the need date for a transmission solution. Therefore, no feasible distribution solution alternatives to the transmission constraint could be found.

The Joint Study has recommended building a new circuit from Leaside TS to Birch Junction. This work will reduce the risk of customer interruptions and provide improved reliability for customers in the area served by Bridgman TS and Dufferin TS. The new circuit will also increase the capability to transfer load between the Leaside and Manby autotransformer stations.

There is also a need to refurbish/replace the existing underground cable section of 115 kV circuit L14W between Birch Junction and Bayview Junction. This section of cable is 50 years old and has been identified as requiring replacement by 2011. HONI recommended that the cable replacement be advanced to 2010 (the earliest date that the Leaside to Birch Junction transmission reinforcement can be placed in-service) so that the work is carried out at the same time as the installation of the new circuit. This will minimize costs and avoid unnecessary disruption to the community.

The IESO's Draft System Impact Assessment Report CAA ID 2006-238 concluded that the proposed plan would alleviate the concern that, under the existing system, there are various contingencies that would result in thermal overloading of the Leaside to Wiltshire circuits. This project also provides operational flexibility to HONI and THESL with respect to load transfers, maintenance and outage scheduling.

This project comprises Line Connection Pool facilities. THESL is required to contribute approximately $35M of capital contribution in accordance with Section 6.3.6 of the Transmission System Code and consistent with HONI's Connection Procedures (submitted for Board Approval under Proceeding EB-2006-0189).

Results

- Increase transmission capacity on Leaside-Bridgman corridor.
- Improve transmission reliability by eliminating load restrictions under first contingency.
- Allow Bridgman TS expansion/upgrade in the future.

Costs[1]

Table 1: THESL Capital Costs and THESL Capital Contributions to HONI ($Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test	Total
Capital	-	-	-	-	-
Capital Contribution	-	5.0	10.0	20.0	35.0
Total Investment	-	5.0	10.0	20.0	35.0

There are no expenditures beyond 2010.

[1] Costs are preliminary and subject to engineering and HONI calculation of capital contribution on final design

COST OF CAPITAL

The purpose of this evidence is to provide an overview of Toronto Hydro-Electric System Limited's ("THESL") capital structure and financing plans for 2007 through 2010. Detailed schedules on capital structure and debt issuances can be found at Exhibit E1, Tabs 2-4, Schedule 1 and Exhibit E1, Tabs 2-4, Schedule 2, respectively.

CAPITAL STRUCTURE

THESL's capital structure for ratemaking purposes is set according to the OEB's Cost of Capital guidelines issued November 30, 2006. Section 4.1 of the guidelines detail the transition from the existing approved capital structure. For THESL, which has a current approved debt:equity ratio of 65:35, the debt:equity split for the test years is set at 62.5:37.5 for 2008, and 60:40 for 2009 and 2010. The debt component in each year includes a deemed 4 percent short-term debt component.

FINANCING PLANS

Equity

The City of Toronto is the sole shareholder of Toronto Hydro Corporation ("THC"). THC, in turn, owns THESL.

The company attempts to maintain an actual capital structure that is similar to the deemed structure through dividend payments to THC, and through managing its debt load. As is described in the next section, due to the significant expenditures expected over the test years, additional debt issuances will be required, which are expected to increase the Company's debt component over the deemed 60 percent and by a marginal amount.

The forecast Return on Equity ("ROE") used to determine Cost of Capital is based on the OEB's Cost of Capital guidelines. Appendix B of the guidelines details the methodology for determining the allowed ROE. ROE is determined according to the formula:

$$ROE_t = 9.35\% + 0.75 \text{ X } (\text{Long-Canada Bond Forecast}_t - 5.50\%)$$

The formula anticipates using the Long-Canada Bond Forecast based on *Consensus Forecasts* publication. However, *Consensus Forecasts* does not produce a forecast of Long-Canada Bonds sufficient to match the Test Years in this application. THESL has instead used forecasts provided by the Conference Board of Canada. The following table shows the ROE calculation using the Conference Board of Canada's forecast for Long-Canada Bond rates.

Table 1: Return on Equity Forecast

Year	Long-Bond	Equity Risk Premium	Return On Equity
Base	5.50%	3.85%	9.35%
2008	4.81%	4.02%	8.83%
2009	5.11%	3.95%	9.06%
2010	5.29%	3.90%	9.19%

THESL has used the above ROE forecasts for the purpose of calculating revenue requirement for the test years in this application. THESL expects however that the ROE forecast produced using the Long Canada bond forecast provided in the January edition of the *Consensus Forecasts* document (and the actual ten- to 30-year spread during the month of January, as described in the OEB's Cost of Capital guidelines) preceding the beginning of each test year will be used to determine the final revenue requirement in each test year. For example, the January 2009 *Consensus Forecasts* forecast of ten-year bonds, plus the January 10 30-year bond yield spread, will determine the allowed ROE to

be included in 2009 rates. THESL will update its revenue requirement for this ROE prior to the beginning of the test year.

Debt

THESL's debt is issued at the THC level, as it is the parent who is rated by the credit rating agencies. The utility is assigned debt through promissory notes between the utility and the parent. The promissory notes are written on the same terms as the parent debt as the borrowing is done on behalf of the corporation's affiliates. A fee of five basis points is charged for administration.

As of December 31, 2006, THESL had outstanding long-term debt in the amount of $1,160.2 million, detailed in Table 2.

Table 2: Medium and Long-Term Debt

Description	Maturity	Principal	Rate
$980M Prom Note	May 4, 2013	980,230,955	6.16%
$180M Prom Note	May 4, 2013	180,000,000	6.16%

The $980M Promissory Note was amended in September 2006 to reflect the new terms of the City Note between the parent and the city (see below). However, for ratemaking purposes, a rate of 5.0 percent, as detailed in the EB-2005-0205 OEB Decision is included in rates for 2006 and 2007. For the Test Years, THESL has determined the cost of this debt using the OEB's cost of capital guidelines. Page 13 of the OEB's report describes the rate to be applied to new affiliate debt:

> "For new affiliated debt, the [OEB] has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate. This deemed long-term debt rate will be calculated as the Long Canada Bond Forecast plus an average spread with "A/BBB" rate corporate bond yields. The Long Canada

> Bond Forecast is comprised of the 10-year Government of Canada bond yield forecast (Consensus Forecast) plus the actual spread between 10-year and 30-year bond yields observed in Bank of Canada data. The average spread with "A/BBB" rate corporate bond yields is calculated from the observed spread between Government of Canada Bonds and "A/BBB" corporate bond yield data of the same term from Scotia Capital Inc., both available form the Bank of Canada."

Based on data from the Bank of Canada, the Long Bond rate for the week of September 6 2006 (when the new terms were executed with the city) was 4.24 percent and the Scotia Capital Inc. "A/BBB" spread was 1.12 percent, combining to determine a debt rate of 5.36 percent. This is the rate that has been used for the City Note for rate-making purposes. THC will pay the city the negotiated rate of 6.11 percent, however, ratepayers will not be responsible for the difference between 5.36 percent and 6.11 percent.

New debt issuance for the 2007 to 2010 period is driven primarily by THESL's capital plans and by the repayment requirements of the amended City Note (see below). Details of the forecast debt issues are in Table 3.

Table 3: Forecast Long-Term Debt Issues

Description	Issue Date	Term	Principal	Rate
1st City Note Repayment	Dec 31, 2007	30-Years	$245,100,000	5.62%
$10M Issue	Jan 1, 2009	30-Years	$10,000,000	6.03%
$65M Issue	Sep 1, 2009	30-Years	$65,000,000	6.19%
2nd City Note Repayment	Dec 31, 2009	10-Years	$245,100,100	5.86%
$25M Issue	Jan 1, 2010	30-Years	$25,000,000	6.26%
$30M Issue	Dec 1, 2010	30-Years	$30,000,000	6.39%

Forecasted debt rates are based on the 10+-year Government Bond forecast contained in the Conference Board of Canada's forecast, plus an appropriate corporate spread for the relevant term. For the 30-year debt issues, this spread is 100 basis points. For the ten-year debt issue, the spread is 55 basis points. In addition, as the debt will be issued by THC, the utility pays an additional five basis points to the parent for administration purposes.

Preference Shares

THESL has no plans to issue any preference shares over the 2007-2010 time frames.

Short-Term Debt

Over the 2008-2010 period, THESL does not forecast the need to issue short-term debt. Cash levels are sufficient to fund the short-term needs throughout the forecast term. Any excess cash, as occurs on a day-to-day basis, is invested in short-term money-market instruments, reducing the overall interest expense of the company. THC maintains a short-term credit facility available for THESL to draw upon in the event short-term funds are required.

As outlined in the Cost of Capital Guidelines by the OEB, short-term debt is deemed throughout the forecast as 4 percent of the company's capital structure for ratemaking purposes. The rate applied is also as directed in the Cost of Capital Guidelines. An additional 20 basis points is added to the short-term debt rate to account for set-up, administration and standby costs related to the short-term credit facility, plus the cost of a letter of credit THESL is required to post with the IESO as its prudential requirement.

CITY NOTE

In September 2006, the Company's parent, THC, amended the terms of its Promissory note with the City of Toronto. Under the amended terms, THC will pay the City 6.11

percent per annum, which is an equivalent rate of interest to the public debenture issued at the same time (and for the same term) as the initial $980M loan from the City. The note also specifies a repayment schedule for the note, with equal payments of $245.1M made on the last business day of 2007, 2009, 2011 and on May 4, 2013.

At the same time of the signing of the renegotiated City note, THESL amended its promissory note with its parent to reflect the terms of the note with the City, including the 6.11 percent (plus five basis points) interest payment and the principal repayment schedule.

For ratemaking purposes, the Company will apply the OEB's Cost of Capital guidelines for affiliate debt in the forecast of the debt rate applied to this component of Long-Term debt in the 2008-2010 test years, as described previously.

INTEREST RATE FORECAST

Exhibit E1, Tab 5, Schedule 1 shows the quarterly forecast of short-term and long-term interest rates as provided by the Conference Board of Canada. The forecasted cost of debt and equity are based on these forecasts and follow the OEB's Cost of Capital guidelines.

Cost of Capital

Table 1: 2006 Historical Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		**Principal**	**Component**	**Cost Rate**	**Return Component**
2		($ Millions)	(%)	(%)	(%)
3	Medium and Long-Term Debt	1,182	65.0	6.38	4.15
4	Short Term Debt	-	-	-	-
5		1,182	65.0		4.15
6					
7	Preferred Shares	-	-	-	-
8	Common Equity	637	35.0	11.08	3.88
9		1,819	100.0		8.03

Table 2: 2006 OEB-Approved

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		**Principal**	**Component**	**Cost Rate**	**Return Component**
2		($ Millions)	(%)	(%)	(%)
3	Medium and Long-Term Debt	1,210	65.0	5.18	3.37
4	Short Term Debt	-	-	-	-
5		1,210	65.0		3.37
6					
7	Preferred Shares	-	-	-	-
8	Common Equity	651	35.0	9.00	3.15
9		1,861	100.0		6.52

Medium and Long-Term Debt Costs

Table 1: 2006 Historical Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	**Description**	**Maturity**	**Principal ($)**	**Coupon Rate**	**Carrying Cost ($)**
2	$980M City Note	May 6, 2013	980,230,955	6.39%	62,636,758
3	$180M Debenture	May 6, 2013	180,000,000	6.16%	11,088,000
4	Financing Costs[1]				298,883
5			1,160,230,955	6.38%	74,023,641

1. Included amortized issue costs and letters of credit

Cost of Capital

Table 1: 2007 Bridge Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		**Principal**	**Component**	**Cost Rate**	**Return Component**
2		($ Millions)	(%)	(%)	(%)
3	Medium and Long-Term Debt	1,200	65.0	5.51	3.58
4	Short Term Debt	-	-	-	-
5		1,200	65.0		3.58
6					
7	Preferred Shares	-	-	-	-
8	Common Equity	646	35.0	9.00	3.15
9		**1,847**	**100.0**		**6.73**

Medium and Long-Term Debt Costs

Table 1: 2007 Bridge Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**Description**	**Issue Date**	**Maturity**	**Principal ($)**	**Coupon Rate**	**Carrying Cost ($)**
2	$980M City Note[1]	May 2003	May 6, 2013	980,230,955	5.36%	52,540,379
3	$180M Debenture	May 2003	May 6, 2013	180,000,000	6.16%	11,088,000
4	City Note Replacement	Dec 31, 2007	Dec 31, 2037	245,057,739	5.62%	37,732
5	Financing Costs[2]					298,883
6	Avg of Monthly Debt Outstanding			1,160,911,671	5.51%	63,964,994

1. Coupon rate reflects amended City Note adjusted for Board's November 30/06 Report on Cost of Capital
2. Includes amortized issue costs

Cost of Capital

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
1		**2008 Test Year**				**2009 Test Year**				**2010 Test Year**			
2		**Principal**	**Component**	**Cost Rate**	**Return Component**	**Principal**	**Component**	**Cost Rate**	**Return Component**	**Principal**	**Component**	**Cost Rate**	**Return Component**
3		($ Millions)	(%)	(%)	(%)	($ Millions)	(%)	(%)	(%)	($ Millions)	(%)	(%)	(%)
4	Medium and Long-Term Debt	1,157	58.5	5.57	3.26	1,197	56.0	5.59	3.13	1,271	56.0	5.67	3.18
5	Short Term Debt	79	4.0	5.17	0.21	86	4.0	5.24	0.21	91	4.0	5.28	0.21
6		1,237	62.5		3.47	1,283	60.0		3.34	1,362	60.0		3.39
7													
8	Preferred Shares	-	-	-	-	-	-	-	-	-	-	-	-
9	Common Equity	742	37.5	8.83	3.31	855	40.0	9.06	3.62	908	40.0	9.19	3.68
10		1,979	100.0		6.78	2,138	100.0		6.96	2,270	100.0		7.06

Medium and Long-Term Debt Costs

Table 1: 2008 Test Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**Description**	**Issue Date**	**Maturity**	**Principal ($)**	**Coupon Rate**	**Carrying Cost ($)**
2	$980M City Note[1]	May 6, 2003	May 6, 2013	735,173,206	5.36%	39,405,284
3	$180M Debenture	May 6, 2003	May 6, 2013	180,000,000	6.16%	11,088,000
4	City Note Replacement	Dec 31, 2007	Dec 2037	245,057,739	5.62%	13,772,245
5	Financing Costs[2]					398,883
6	Avg of Monthly Debt Outstanding			**1,160,230,945**	5.57%	**64,664,412**

1. Coupon rate reflects amended City Note adjusted for Board's November 30/06 Report on Cost of Capital
2. Includes amortized issue costs

Table 2: 2009 Test Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**Description**	**Issue Date**	**Maturity**	**Principal ($)**	**Coupon Rate**	**Carrying Cost ($)**
2	$980M City Note[1]	May 6, 2003	May 6, 2013	735,173,206	5.36%	39,405,284
3	$180M Debenture	May 6, 2003	May 6, 2013	180,000,000	6.16%	11,088,000
4	City Note Replacement	Dec 31, 2007	Dec 2037	245,057,739	5.62%	13,772,245
5	New Capex	Jan 1, 2009	Jan 2038	10,000,000	6.03%	603,000
6	New Capex	Sept 1, 2009	Sept 2038	65,000,000	6.19%	1,344,841
7	City Note Replacement	Dec 31, 2009	Dec 2019	245,057,739	5.86%	39,344
8	Financing Costs[2]					465,550
9	Avg of Monthly Debt Outstanding			**1,192,578,328**	5.59%	**66,718,263**

1. Coupon rate reflects amended City Note adjusted for Board's November 30/06 Report on Cost of Capital
2. Includes amortized issue costs

Table 3: 2010 Test Year

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**Description**	**Issue Date**	**Maturity**	**Principal ($)**	**Coupon Rate**	**Carrying Cost ($)**
2	$980M City Note[1]	May 6, 2003	May 6, 2013	490,115,457	5.36%	26,270,188
3	$180M Debenture	May 6, 2003	May 6, 2013	180,000,000	6.16%	11,088,000
4	City Note Replacement	Dec 31, 2007	Dec 2037	245,057,739	5.62%	13,772,245
5	New Capex	Jan 1, 2009	Jan 2038	10,000,000	6.03%	603,000
6	New Capex	Sept 1, 2009	Sept 2038	65,000,000	6.19%	4,023,500
7	City Note Replacement	Dec 31, 2009	Dec 2019	245,057,739	5.86%	14,360,384
8	New Capex	Jan 1, 2010	Jan 2040	25,000,000	6.26%	1,565,000
9	New Capex	Dec 1, 2010	Dec 2040	30,000,000	6.39%	159,750
10	Financing Costs[2]					765,550
11	Avg of Monthly Debt Outstanding			**1,280,652,413**	5.67%	**72,607,617**

1. Coupon rate reflects amended City Note adjusted for Board's November 30/06 Report on Cost of Capital
2. Includes amortized issue costs

Canadian Interest and Exchange Rate Forecasts

Table 1: Quarterly Forecast

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	**Year**	**3-Month T-Bills (%)**	**90-Day Commercial Paper (%)**	**1-3 Year Govt Bonds (%)**	**3-10 Year Govt Bonds (%)**	**10+ Year Govt Bonds (%)**	**Exchange Rate ($Cdn/US)**
2	2006:1(A)	3.66	3.82	3.92	4.07	4.22	1.155
3	2006:2(A)	4.15	4.34	4.30	4.45	4.60	1.122
4	2006:3(A)	4.15	4.33	4.05	4.09	4.25	1.121
5	2006:4	4.17	4.32	4.01	4.10	4.14	1.139
6	2007:1	4.18	4.30	3.92	4.10	4.03	1.154
7	2007:2	4.18	4.34	4.04	4.22	4.19	1.153
8	2007:3	4.18	4.37	4.13	4.32	4.32	1.149
9	2007:4	4.26	4.49	4.27	4.45	4.48	1.143
10	2008:1	4.42	4.69	4.45	4.62	4.66	1.141
11	2008:2	4.42	4.72	4.51	4.69	4.77	1.141
12	2008:3	4.42	4.74	4.56	4.75	4.86	1.144
13	2008:4	4.42	4.76	4.59	4.80	4.94	1.146
14	2009:1	4.42	4.77	4.62	4.85	5.02	1.148
15	2009:2	4.42	4.79	4.65	4.89	5.08	1.151
16	2009:3	4.42	4.80	4.66	4.92	5.14	1.154
17	2009:4	4.42	4.81	4.68	4.95	5.19	1.156
18	2010:1	4.42	4.82	4.69	4.97	5.24	1.161
19	2010:2	4.42	4.83	4.70	4.99	5.28	1.164
20	2010:3	4.42	4.84	4.71	5.01	5.31	1.166
21	2010:4	4.42	4.84	4.71	5.03	5.34	1.169

Table 2: Annual Averages

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	**Year**	**3-Month T-Bills (%)**	**90-Day Commercial Paper (%)**	**1-3 Year Govt Bonds (%)**	**3-10 Year Govt Bonds (%)**	**10+ Year Govt Bonds (%)**	**Exchange Rate ($Cdn/US)**
2	2006	4.03	4.20	4.07	4.18	4.30	1.134
3	2007	4.20	4.38	4.09	4.27	4.25	1.150
4	2008	4.42	4.72	4.53	4.72	4.81	1.143
5	2009	4.42	4.79	4.65	4.90	5.11	1.152
6	2010	4.42	4.83	4.70	5.00	5.29	1.165

Source: Conference Board of Canada, December 2006

Rating Report

Report Date: July 24, 2007
Press Released: July 24, 2007
Previous Report: April 26, 2006

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DBRS
Insight beyond the rating.

Toronto Hydro Corporation

Rating

Rating	Trend	Rating Action	Debt Rated
R-1 (low)	Stable	Confirmed	Commercial Paper/Short-Term Obligations
A	Stable	Confirmed	Senior Unsecured Debentures & MTNs

Rating History	Current	2006	2005	2004	2003	2002
Commercial Paper/Short-Term Obligations	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Senior Unsecured Debentures & MTNs	A	A	A	A (low)	A (low)	A

Rating Update

DBRS has confirmed the ratings of Toronto Hydro Corporation (Toronto Hydro or the Company) as follows: Senior Unsecured Debentures & MTNs at "A" and Commercial Paper/Short-Term Obligations at R-1 (low), both with Stable trends. The ratings confirmation reflects Toronto Hydro's low business risk profile, accompanied by the continuation of a solid financial profile, which is supported by a strong balance sheet, good credit metrics and a modestly improving regulatory environment in Ontario, which underpins the current ratings.

The regulatory environment in Ontario continues to modestly improve, despite the April 2006 decision of the Ontario Energy Board (OEB) that established an overall lower return on equity (ROE) for Toronto Hydro's regulated subsidiary and reduced allowable interest rate recoverable on related party debt, namely, the outstanding $980 million promissory note between Toronto Hydro-Electric System Limited (THESL) and the Company from 6.8% to 5.0% per annum. (Continued on page 2.)

Rating Considerations

Strengths:

- Regulated electricity distribution has low business risk and provides long-term stability to earnings and cash flows
- Strong franchise area
- Solid credit metrics/balance sheet
- Strong reliability measures/operational efficiency
- Expiration of competitive electricity contracts and the divestiture of non-regulated operations

Challenges:

- Significant upcoming capital investment program
- Approved ROE sensitive to long-term interest rates
- Earnings sensitive to volume of electricity sold
- Unable to access equity capital markets
- Significant external financing required

Financial Information

	12 mos ended Mar. 2007	For the year ended December 31 2006	2005	2004	2003
Total debt (CAD millions) (1)	1,216	1,216	1,216	1,215	1,215
Total debt-to-capital (%) (1)	57.4%	57.7%	59.0%	59.7%	61.2%
Net debt -to-capital (%) (1)	40.5%	42.1%	37.2%	40.7%	46.2%
Cash flow/total debt (%) (1)	16.4%	17.9%	16.6%	17.4%	20.9%
Cash flow/capital expenditures (times)	1.08	1.18	1.44	1.93	2.27
EBIT coverage (times) (1)	2.21	2.39	2.27	2.25	2.94
Operating cash flow (CAD millions)	198.8	217.9	201.6	211.6	254.3
Core net income (CAD millions)*	68	77	64	64	102
Reported net income (CAD millions)	107	92	92	97	98
Return on average equity	7.7%	8.9%	7.7%	8.0%	14.2%
Electricity throughputs (million kWh)	na	25,527	26,372	25,636	25,733

*DBRS adjusted to exclude mark-to-market in revenues. (1) DBRS adjusted for operating lease equivalents.

The Company

Toronto Hydro Corporation is a holding company with the following subsidiaries: Toronto Hydro-Electric System Ltd. (THESL), which distributes electricity; Toronto Hydro Energy Services Inc. (Energy Services), which provides street lighting and expressway lighting services and energy-efficient products and services; and Toronto Hydro Telecom Inc., which provides fibre-optic capacity and manages data communication services. Toronto Hydro's sole shareholder is the City of Toronto (the City), rated AA by DBRS.

RATING UPDATE (Continued from page 1.)

The OEB decision had a modest impact on the Company's earnings and key coverage ratios. As such, Toronto Hydro will repay the promissory note over a seven-year period in four $245 million tranches, which places significant dependence on external financing requirements. Maintaining adequate access to the debt markets is critical during this refinancing schedule.

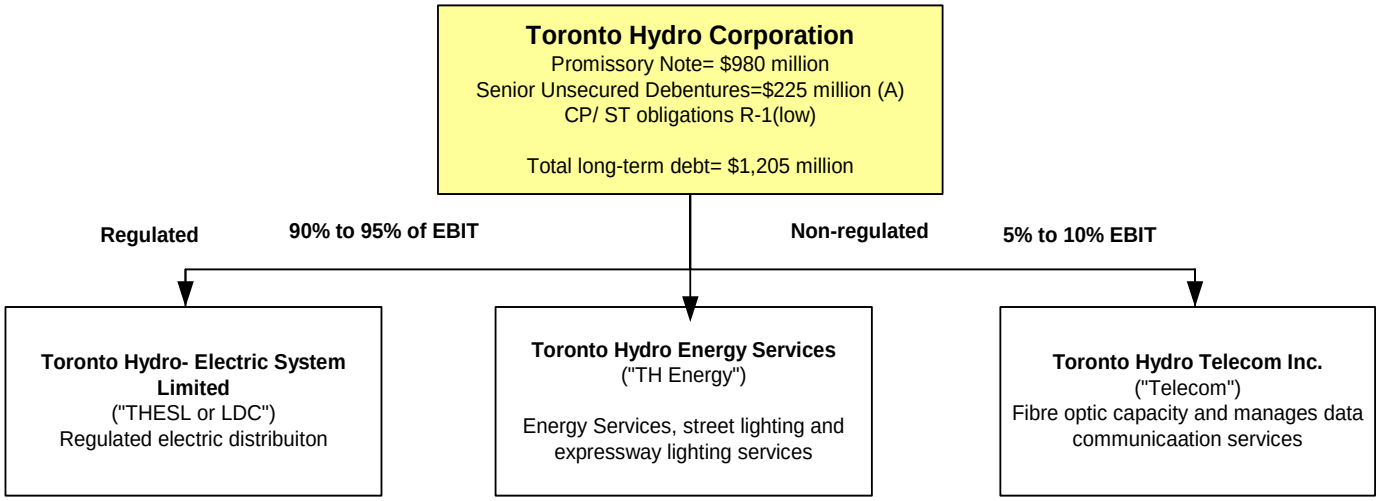
Furthermore, on the regulatory front, the OEB's new regulatory framework under the 2nd Generation Incentive Regulation Model (IRM) and Cost of Capital is viewed by DBRS as reasonable, but largely credit neutral for Toronto Hydro, providing sufficient earnings and cash flow stability. In 2008, DBRS expects THESL to file a three-year rate application (2008 to 2010) encompassing, among other things, a ten-year capital plan and a workforce renewal strategy.

Toronto Hydro is entering a significant capital investment program to modernize its distribution system. Recently, THESL completed a ten year modernization assessment for the distribution system and filed a capital plan of $1.2 billion with the OEB for distribution assets. This capital plan focuses on the modernization of THESL's distribution system. DBRS expects capital investment in the range of $275 million to $300 million per annum, a 55% to 60% increase from 2006 capital expenditure levels, which is projected to result in manageable free cash flow deficits over the medium term. As such, moderate external financing is required during this build-out phase, in which the regulatory environment plays a paramount role in ensuring a predictable and stable environment for investment.

DBRS anticipates earnings and operating cash flow to remain under pressure over the near term, from lower regulated returns, limited earnings contribution from non-regulated operations and increased capital expenditures; however, leverage and coverage ratios are expected to remain within ranges consistent with the assigned ratings. Over the longer term, earnings growth should trend higher reflecting the following: (1) the equity thickness of the capital structure increasing from 35% to 40% over a two-year period beginning on May 1, 2008; (2) THESL's revenue requirement is re-based in 2008; and (3) THESL continues strong reliability measures and prudent cost management.

DBRS believes that over the medium term, the Company's operations will remain relatively stable going forward, barring any unexpected regulatory or political decisions.

CORPORATE STRUCTURE



RATING CONSIDERATIONS

Strengths

(1) Toronto Hydro is predominately a regulated electric distribution company that operates in a modestly improving regulatory environment. DBRS expects THESL to file a three-year cost-of-service rate application (2008 to 2010) encompassing, among other things, a ten-year capital plan and a workforce renewal strategy. DBRS views the new regulatory framework under the 2nd Generation IRM and Cost of Capital decision as reasonable, providing sufficient earnings and cash flow stability. DBRS believes

the OEB will be supportive in the recovery of capital costs.

(2) Toronto Hydro is one of the largest municipally owned local distribution companies (LDCs) in Canada, serving a large customer base (678,000 customers) in a strong franchise area. More than 95% of Toronto Hydro's electricity sales are to residential and general service customers, which have relatively stable demand year over year, as these customers are less sensitive to economic cycles.

(3) Toronto Hydro's credit metrics remain solid for a utility that benefits from low business risk and are consistent with current ratings: debt-to-capital ratio at 57.4%, EBIT interest coverage at 2.21 times and cash flow-to-debt at 16.4% (12 months ended March 2007). Although DBRS expects coverage ratios to experience modest downward pressure given the higher capital expenditures driving manageable free cash flow deficits, financial metrics are expected to remain within a range that is reasonable for the assigned rating.

(4) THESL continues to exceed OEB service level targets, which should provide a better platform to facilitate a constructive relationship with the regulators.

(5) Toronto Hydro's business risk profile has improved gradually over the years as higher-risk, non-regulated operations have continued to represent a decreasing proportion of consolidated operations. Toronto Hydro is focused on its core regulated utility business, which will account for approximately 95% of consolidated EBIT, providing for a predictable and stable earnings profile going forward.

Challenges

(1) The Company is entering a build-out program to enhance the reliability of the system and replace aging assets. The Company has filed a capital plan of $1.2 billion with the OEB for distribution assets. Going forward, DBRS expects capital investment in the range of $275 million to $300 million per annum through 2011, which, combined with dividends, is expected to exceed operating cash flows by approximately $100 to $150 million per year. The manageable free cash flow deficits are expected to place modest pressure on the balance sheet and coverage ratios.

(2) Regulatory-allowed ROE levels are low and could continue to decline if the longer-term interest rates decline. The ROE of 9.0% in 2007 (also 9% in 2006) is an 88 basis point decline from 9.88% in 2005. However, the lower ROE is expected to be somewhat offset as the equity component of the capital structure increases from 35% in 2007 to 40% in 2009.

(3) Earnings and cash flows for electricity distribution companies are partially dependent on the volume of electricity sold, given that rates typically include a variable charge component. Seasonality, economic cyclicality and weather variability directly impact the volume of electricity sold, and hence, revenue earned from electricity sales.

(4) Due to municipal ownership, Toronto Hydro does not have access to the equity capital markets. This limits the Company's financial flexibility, as free cash flow deficits will likely be financed with cash on the balance sheet ($358 million at March 31, 2007) or debt issuance. However, the dividend payout with the City is reasonable and modestly lower than the majority of municipally owned utilities across Canada.

(5) The Company is dependent upon the debt markets to refinance the $980 million City promissory note and fund capital investments in THESL. Over the next seven years, Toronto Hydro will have to refinance 100% ($1,205 million) of its outstanding debt, exposing the company to interest rate risk. Maintaining adequate access to the debt markets is critical during this refinancing and build-out phase. DBRS believes the following factors should help facilitate Toronto Hydro's access to the debt markets: (a) reduced uncertainty associated with the regulatory environment and (b) low business risk profile accompanied by a strong financial profile. Refinancing the debt could expose the Company to some upside interest rate risk given the current inflationary environment and the modestly upward sloping yield curve. However, because much of this debt was incurred for THESL, a market-based interest rate on third-party debt should be fully recoverable from ratepayers. Furthermore, DBRS believes the Company will go to the market with longer-dated debentures and spread out the maturities in an effort to match debt obligations with its average asset life and lessen the refinancing of a high percentage of outstanding debt during a short period of time.

REGULATION

Toronto Hydro's electricity distribution operations are regulated by the Ontario Energy Board (OEB) under the *Electricity Act, 1998* (the Electricity Act), as modified by the following noteworthy amendments:

- The *Electricity Pricing, Conservation and Supply Act, 2002* (Bill 210) – December 9, 2002;
- The O*ntario Energy Board Amendment Act, 2003* (Bill 4) – December 18, 2003; and
- The *Electricity Restructuring Act, 2004* (Bill 100) – December 9, 2004.

Currently, THESL operates under cost-of-service regulation with a deemed ROE of 9.0%.

In April 2006, the OEB decreased Toronto Hydro's distribution rates for the May 1, 2006, to April 30, 2007, period, representing a revenue reduction of approximately $58 million. The methodology used by the OEB to establish the distribution rates was based on a rate base of $1.861 billion, a deemed debt-to-equity structure of 65-to-35 and an allowed ROE of 9.0%. Furthermore, the OEB reduced allowable interest rate recoverable on related party debt to 5.0% from 6.80%, which impacted Company's earnings, cash flows and coverage ratios.

On December 20, 2006, the OEB issued a 2007 rate adjustment model (2nd Generation Incentive Regulation Model and Cost of Capital) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. As a result, base distribution rates, exclusive of rate riders, were adjusted formulaically to reflect an allowance for inflation, a fixed productivity offset of 1.0%, and removal of the federal large corporation tax. As such, no major financial impact for distributors, only a marginal increase in revenues, is expected due to the inflation factor generally being slightly higher than the productivity factor. In each of three subsequent years, approximately one-third of the electricity distributors will have their distribution rates reviewed and reset by the OEB through a cost-of-service type of rate proceeding. LDCs re-based in 2008 will be subject to an Incentive Rate Mechanism applied in succeeding years up to the 2010 rate year. By 2010, all electricity distributors in Ontario will have undergone a re-basing of rates. The net effect of the OEB decision in 2007 was to provide for approximately a 0.9% increase in base distribution rates to all customer classes for the May 1, 2007 to April 30, 2008 period.

On March 27, 2007, the OEB advised THESL regarding the March 21, 2007, rate application that it would consider the smart meter deferral account (approximately $36 million to the end of 2006) and the adjustment to rate base in a "combined" proceeding that will commence after May 1, 2007. In addition, the OEB agreed to proceed with a hearing for THESL's recovery of costs for lost revenue and utility incentives due to the successful conservation programs in 2005 and 2006 (approximately $10.4 million). Hearings into both these matters were held over the June–July 2007 period and have now concluded. THESL expects that a decision into these matters will be released by the OEB in time for rate adjustments to be made on November 1, 2007.

EARNINGS AND OUTLOOK

(CAD millions)	12 mos ended Mar. 2007	For the year ended December 31 2006	2005	2004	2003
Net operating revenues *	513.8	520.5	512.2	509.7	555.0
Operating costs	344.2	331.6	322.8	320.8	312.9
EBITDA*	309.2	326.3	321.0	323.7	371.1
EBIT*	169.7	188.9	189.4	188.9	242.1
Gross interest expense	76.5	78.8	83.1	83.8	81.9
Payments in lieu of income taxes	43.1	50.9	56.4	53.5	69.9
Core net income*	67.7	76.9	64.0	63.9	101.9
Reported net income	107.5	92.4	92.4	97.3	98.4
Return on equity	8%	9%	8%	8%	14%
Operating margin	33%	36%	37%	37%	44%
Reported regulated EBIT	na	187	194	174	176
Reported non-regulated EBIT	na	23	30	65	57
% of EBIT non-regulated	na	11%	13%	27%	25%

*DBRS adjusted to exclude mark-to-market in revenues.

Summary

- Earnings, as measured by EBIT, declined modestly for the 12 months ended March 2007, largely reflecting the related party interest decision and increased operating expenses. Furthermore, the decline in EBIT is partially a result of the sale of its water heater business to Consumer's Waterheater Income Fund for cash consideration of $40.8 million, subject to closing adjustments and transaction costs. The results of the water heater operations and financial position have been reflected as discontinued operations.
- DBRS notes the recent upswing in operating costs was primarily driven by the increased employee head count as Toronto Hydro integrates a new workforce to replace the existing demographic of pension-eligible employees.
- Interest rate expense decreased moderately reflecting the amended promissory note between the Company and the City, which represented a 69 basis point decrease (approximately $6.7 million) from the 6.80% to 6.11%.
- The following factors continue to impact earnings:
  - Regulatory-approved ROE levels, which are tied to Canadian long-term bond yields.
  - Regulatory approvals for increases in the rate base, in line with capital expenditures, which will be added to the rate base at the completion of system upgrades.
  - Operating efficiency, to outperform the 1.0% productivity factor.
  - Significantly lower earnings contribution from non-regulated businesses.
  - Weather conditions directly impact the volume of electricity sold and revenues earned.
  - OEB decision to amend the deemed interest rate on the Company's debt component, creating a 111 basis point spread on $980 million outstanding debt that will not be recovered through distribution rates.
- Net income has generally tracked EBIT; however, it did not in 2007 due to the sale of the water heater operations.

Outlook

EBIT will continue to be pressured over the near term as lower regulated returns and limited earnings contribution from non-regulated operations pressure earnings. However, earnings should register moderate growth beyond 2008, reflecting the following:

- DBRS expects THESL to file a three-year cost-of-service rate application (2008 to 2010) encompassing a capital plan and a facilities application.
- Equity component of capital structure to increase to 40% in 2010 from 35% in 2007.
- OEB will address the recovery of smart meter costs (approximately $36 million to the end of 2006) and lost revenue from successful execution of Conservation Demand Management programs ($10.4 million) over the next three to four months.
- The rate base will reflect the significant increase in capital expenditures over the next few years.
- The OEB's decision to reduce the allowable interest rate recoverable on related party debt

will continue to have an impact on earnings of approximately $10 million per year. This negative impact should be negated over time as related party debt is refinanced with third party debt.

- The Company's regulated electricity distribution business will continue to provide a high degree of stability to earnings and cash flows over the longer term.

FINANCIAL PROFILE AND OUTLOOK

Cash-Flow Statement	12 mos ended	For the year ended December 31			
(CAD millions)	Mar. 2007	2006	2005	2004	2003
Net income (before non-recurring)	68	77	64	64	102
Depreciation and amortization	140	137	132	135	129
Other non-cash adjustments	(9)	4	6	13	23
Cash Flow From Operations *	**199**	**218**	**202**	**212**	**254**
Dividends paid	(46)	(46)	(68)	(49)	(5)
Capital expenditures	(185)	(185)	(140)	(110)	(112)
Gross Free Cash Flow	**(32)**	**(14)**	**(7)**	**53**	**137**
Changes in working capital	(43)	(145)	100	2	112
Net Free Cash Flow	**(75)**	**(158)**	**94**	**54**	**250**
Acquistions	0	0	(60)	0	0
Dispositions	42	1	5	5	1
Change in regulatory assets (increase)/ decrease	17	(4)	21	15	(4)
Non-recurring / Other	39	40	23	10	(0)
Cash Flow before Financing	**23**	**(122)**	**82**	**85**	**247**
Net debt financing	0	0	0	0	9
Customer deposits / repayment of capital lease	(1)	1	(22)	4	6
Net Change in Cash	**23**	**(121)**	**62**	**89**	**265**

Key Financial Ratios					
Total debt in capital structure (1)	1,215.6	1,215.6	1,216.0	1,214.7	1,214.7
Total debt-to-captial (1)	57.4%	57.7%	59.0%	59.7%	61.2%
Cash flow/total debt (1)	16.4%	17.9%	16.6%	17.4%	20.9%
EBITDA coverage (times) (1)	4.01	4.11	3.83	3.84	4.50
EBIT coverage (times) (1)	2.21	2.39	2.27	2.25	2.94
Dividend payout	68%	60%	106%	77%	5%

*Operating cash flow adjusted to exclude mark-to-market in revenues. (1)DBRS adjusted for operating lease equivalents

Summary

- Operating cash flow has remained reasonably stable, with the recent modest decline largely tracking EBIT.
- The recent upward trend in capital expenditures, combined with dividends (set at the greater of $25 million or 50% of net income), has resulted in very modest free cash flow deficits.
- The large swings in working capital are mainly due to the timing of the Company receiving and paying a customer rebate (pass-through of the commodity cost of electricity) from the Independent Electricity System Operator (IESO).
- In February 2007, the Company sold its water heater assets to Consumers' Waterheater Income Fund for approximately $40.8 million. This is in line with the Company's focus on its electric distribution business.
- Key credit metrics have remained relatively stable from 2004 levels, as debt levels have been constant with a growing equity base and lower interest expense on the Company's promissory note, and remain solidly within the current rating category for a low-risk distribution utility with debt-to-capital at 57.4%, EBIT interest coverage at 2.21 times and cash flow-to-debt at 16.4%.

Outlook

- Operating cash flows will experience moderate downward pressure as earnings contribution from non-regulated segment declines, partially offset by higher depreciation trending in line with higher capital expenditures.
- With Toronto Hydro entering a significant capital build-out program, DBRS expects:

- Annual capital expenditures will average approximately $275 million to $300 million from 2007 to 2011, due to the capital plan of $1.3 billion filed with the OEB for the modernization of the distribution system.
- The current dividend policy will increase liquidity needs due to the formula approach over the medium term as the Company is committed to investing heavily in the distribution system.
- As such, DBRS expects the Company will incur manageable levels of free cash flow deficits (in the range, on average, of $100 million to $150 million per year), which will be financed through debt issuances and current cash on the balance sheet ($357 million).

- Toronto Hydro is expected to file a three-year cost-of-service rate application (2008 to 2010) that will encompass, among other things, a capital plan and a workforce renewal strategy. This should improve operating cash flow as the invested capital is added to the rate base, thereby increasing the earnings profile.
- Toronto Hydro's remaining non-regulated operations are relatively low-risk and are expected to generate reasonable cash flows.
- The Company's leverage is not expected to exceed 60% as a growing equity base should largely offset incremental debt levels. Cash flow-to-debt and interest coverage ratios are expected to experience modest pressure until new assets enter rate base, but they should remain within the range of the current assigned ratings for a regulated distribution utility.

LONG-TERM DEBT MATURITIES AND BANK LINES

Repayment schedule	%	$ millions
2007	20%	245
2008	0%	0
2009	20%	245
2010	0%	0
2011	20%	245
2012	0%	0
2013	39%	470
Total		**1,205**

Credit Facility ($ millions)	Amount	LC's	Available	Expiry
Three year revolving credit facility	500	80	420	5/4/2008

Long-term debt	Int. rate	$ millions	Maturity
Senior Unsecured debentures	6.1%	225	5/7/2013
Promissory note payable to the City	6.1%	980	2007 to 2013
Total debt		**1,205**	

Long-Term Debt

- Toronto Hydro has long-term debt (senior unsecured and promissory notes, $1,205 million outstanding at March 2007) and a three-year revolving credit facility ($500 million).
  - The debt-repayment schedule is considerable over the next seven years, as Toronto Hydro will have to refinance 100% of its outstanding debt. Refinancing the debt could expose the Company to some interest rate risk. DBRS believes the Company can mitigate future refinancing risk by issuing longer dated debentures with spread-out maturities to better match debt obligations with asset lives.
- DBRS believes refinancing the promissory note is within Toronto Hydro's financing capacity given its strong financial profile and modestly improving regulatory environment.
- In January 2006, the Company filed a short-form base shelf prospectus allowing it to issue up to $1 billion of senior unsecured debentures.
- The debenture indenture includes the following covenants:
  - Any additional indebtedness is subject to a 75% capitalization ratio test
  - Negative pledge clause.
  - Limitations on designated subsidiary indebtedness.
- The $980.2 million promissory note with the City of Toronto ranks pari passu with the Senior Unsecured Debentures.

Liquidity

- Liquidity requirements will increase over the medium term to accommodate higher capital expenditures and regulatory working capital needs, estimated at $300 million. DBRS notes that Toronto Hydro has reasonable liquidity, with $420 million unused capacity under the Company's $500 million credit line at the end of March 31, 2007.
- DBRS notes that Toronto Hydro currently does not have a commercial paper program.

Toronto Hydro Corporation

Balance Sheet (CAD millions)	12 mos ended	As at December 31			12 mos ended	As at December 31	
Assets	Mar. 2007	2006	2005	**Liabilities and Equity**	Mar. 2007	2006	2005
Cash + short-term investments	357.8	327.5	448.4	Short-term debt	245.1	245.1	330.0
A/R + unbilled revenue	419.0	435.3	445.9	A/P + accruals	277.1	285.2	423.8
Inventories	25.5	22.5	18.2	Elec. mark-to-market	0.0	0.0	86.9
Electricity mark-to-market	0.0	0.0	113.3	Other current liab.	25.4	24.9	100.6
Prepaids and other	4.0	15.2	35.4	**Current Liabilities**	547.6	555.1	941.2
Current Assets	806.3	800.5	1,061.1	Customer deposits	19.7	25.9	2.9
Net fixed assets	1,665.4	1,656.9	1,624.7	Long-term debt	960.2	960.2	875.2
Future income tax asset	15.9	16.0	22.3	Employment benefits	136.8	134.7	125.4
Regulatory assets	70.8	66.5	63.8	Other liabilities	42.1	23.7	28.6
Intangibles & other assets	50.5	51.8	47.4	Shareholders' equity	902.5	892.1	845.9
Total	2,608.9	2,591.7	2,819.3	**Total**	2,608.9	2,591.7	2,819.3

Ratio Analysis	12 mos ended	For the year ended December 31			
Liquidity Ratios	Mar. 2007	2006	2005	2004	2003
Current ratio	1.47	1.44	1.13	1.24	1.11
Total debt-to-capital (1)	57.4%	57.7%	59.0%	59.7%	61.2%
Cash flow/total debt (1)	16.4%	17.9%	16.6%	17.4%	20.9%
Cash flow/capital expenditures	1.08	1.18	1.44	1.93	2.27
(Cash flow-dividends)/capital exp.	0.83	0.93	0.95	1.48	2.23
Debt/EBITDA (1)	3.93	3.73	3.79	3.75	3.27
Common dividend payout ratio	68.2%	60.1%	106.3%	77.0%	4.9%
Deemed equity	35%	35%	35%	35%	35%
Coverage Ratios					
EBITDA interest coverage (1)	4.02	4.12	3.84	3.85	4.51
EBIT interest coverage (1)	2.21	2.39	2.27	2.25	2.94
Profitability/Operating Efficiency					
Operating margin	7.6%	8.6%	7.4%	8.9%	10.1%
Net margin (before extras.)	13.2%	14.8%	12.5%	12.5%	18.4%
Return on average equity (before extras.)	7.5%	8.9%	7.7%	8.0%	14.2%

Electricity Throughputs	2006	2005	2004	2003
Residential	5,352	5,724	5,412	5,408
General service	17,583	17,957	17,502	17,627
Large users	2,592	2,563	2,594	2,570
Street lighting	0	128	128	128
Total (million kWh)	25,527	26,372	25,636	25,733
Growth in electricity throughputs	-3.2%	2.9%	-0.4%	-2.2%

Customers	2006	2005	2004	2003
Residential	599,080	597,469	594,976	590,109
General service	78,978	79,162	78,150	78,517
Large users	49	47	47	47
Street lighting	1	1	1	1
Total	678,108	676,679	673,174	668,674
Growth in customer base	0.2%	0.5%	0.7%	0.6%

(1) DBRS adjusted for operating lease equivalents. Financial results reflect adjustment to exclude mark-to-market in revenues

Note:
All figures are in Canadian dollars unless otherwise noted.

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PROMISSORY NOTE

Principal Sum Cdn $180,000,000

FOR VALUE RECEIVED, the undersigned hereby unconditionally promises to pay to the order of Toronto Hydro Corporation ("THC") on May 6th, 2013 (the "Due Date") the principal sum of **(ONE-HUNDRED EIGHTY MILLION DOLLARS)** ($180,000,000) (the "Principal Sum") in lawful money of Canada at 14 Carlton Street, Toronto, Ontario M5B 1K5, or such other place as THC may designate by notice in writing to the undersigned and to pay interest on the Principal Sum at the rate of 6.16% per annum calculated and accruing from the date hereof to the Due Date and thereafter until the Principal Sum is repaid to THC. Interest shall be calculated and payable semi-annually in arrears on the 7th of May and 7th of November in each year at the same address with the first payment payable on November 7, 2003. Interest both before and after default and judgement on the principal amount and overdue interest shall be payable at the aforementioned rate.

All payments or any part thereof may be extended, rearranged, renewed or postponed by THC. No delay or failure by THC to exercise any right or remedy against the undersigned shall be construed as a waiver of that or any right or remedy nor shall any waiver hereunder be deemed to be a waiver of subsequent default. On the Due Date, THC may, after consultation with the undersigned, replace this promissory note for one or more debt instruments of the undersigned with any change to any provision hereunder, including reducing or increasing the rate of interest payable on the principal amount owing at the time of replacement, extending the date on which the principal amount hereunder is due and payable or adjusting the principal sum payable hereunder, all as evidenced by the written acceptance by said debt instrument or instruments by the Treasurer of THC.

The undersigned hereby waives presentment, demand, protest or other notice of every kind in the enforcement of this promissory note. All amounts owing hereunder will be paid by the undersigned without regard for any equities between the undersigned and THC or any right of set-off or cross-claim.

In the event of a default hereunder the undersigned agrees to pay all expenses, including without limitation, reasonable legal fees (on a solicitor and his own client basis), incurred by THC in endeavoring to enforce its rights hereunder. All such amounts shall bear interest at the rate mentioned above.

This promissory note is non-negotiable and non-assignable without the prior written consent of the undersigned.

DATED at Toronto, Ontario, as of the 7th day of May, 2003.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By: _____
Name: Wanda Liczyk
Title: Senior Vice-President & Chief Financial Officer

By: _____
Name: Pankaj Sardana
Title: Vice-President, Treasurer

EXECUTION COPY

AMENDED AND RESTATED PROMISSORY NOTE

Principal Sum: Cdn$980,230,955 **Date: May 1, 2006**

RECITALS:

A. The undersigned (the **"Issuer"**) issued a promissory note (the **"Original Note"**) dated May 7, 2003 to Toronto Hydro Corporation (the **"Holder"**) in the principal sum of **NINE HUNDRED AND EIGHTY MILLION, TWO HUNDRED AND THIRTY THOUSAND, NINE HUNDRED AND FIFTY-FIVE CANADIAN DOLLARS** (Cdn$980,230,955) (the **"Principal Sum"**).

B. The Issuer has paid all interest on the Principal Sum payable under the Original Note up to and including April 30, 2006.

C. The Issuer and the Holder have agreed to amend and restate the Original Note effective May 1, 2006 by changing the interest rate payable by the Issuer to the Holder and providing a schedule for payment of the Principal Sum, including the dates on which payments are to be made and the amount of the Principal Sum to be paid on such dates, including the Expiry Date.

FOR VALUE RECEIVED, the Issuer hereby unconditionally promises to pay to or to the order of the Holder at 14 Carlton Street, Toronto, Ontario M5B 1K5, or at such other place in Canada as the Holder may designate by notice in writing to the Issuer:

(a) the Principal Sum in accordance with the payment schedule set out in Section 2.1, and

(b) interest on the unpaid Principal Sum from time to time from the date hereof, both before and after maturity, default and judgment and until actual payment, at the Interest Rate, calculated quarterly in arrears and payable on each Interest Payment Date.

1. INTERPRETATION

1.1 Definitions.

"Business Day" shall mean any day other than a Saturday or Sunday or a day on which banks are not open for business in Toronto, Canada.

"Expiry Date" shall mean May 6, 2013.

"Event of Default" shall mean:

(a) failure to pay principal on the Promissory Note when due;

(b) failure to pay interest on the Promissory Note when due, if such failure continues for a period of 30 days;

(c) the sale, transfer, lease or other disposition, in a transaction or series of related transactions, of all or substantially all of the property and assets of the Issuer;

(d) failure by the Issuer to pay principal, premium (if any) or interest due on any indebtedness, the principal amount of which is more than $50 million in the aggregate, beyond the applicable grace period, if any, under the terms of such indebtedness;

(e) failure by the Issuer to observe or perform any provision of any agreement under which indebtedness is created if such failure has the effect of causing more than $50 million of such indebtedness in the aggregate to become due and payable or to be required to be redeemed or repurchased before its stated maturity;

(f) the rendering by a court of competent jurisdiction of one or more judgments against the Issuer in an aggregate amount of more than $50 million if the judgments remain undischarged or unstayed for more than 30 days;

(g) proceedings are commenced for the winding-up, liquidation or dissolution of the Issuer, a decree or order of a court of competent jurisdiction is entered adjudging the Issuer a bankrupt or insolvent, or a petition seeking reorganization, arrangement or adjustment of or in respect of the Issuer is approved under applicable law relating to bankruptcy, insolvency or relief of debtors, unless such proceedings, decrees, orders or approvals are actively and diligently contested by the Issuer in good faith and are dismissed or stayed within 60 days of commencement;

(h) the Issuer makes an assignment for the benefit of its creditors, or petitions or applies to any court or tribunal for the appointment of a receiver or trustee for itself or any substantial part of its property, or commences for itself or acquiesces in any proceeding under any bankruptcy, insolvency, reorganization, arrangement or readjustment of debt law or statute or any proceeding for the appointment of a receiver or trustee for itself or any substantial part of its property, or suffers any such receivership or trusteeship and allows it to remain undischarged or unstayed for 30 days; or

(i) a resolution is passed for the winding-up or liquidation of the Issuer.

"Interest Payment Date" shall mean the last day of March, June, September and December in each year or part year before the Expiry Date, and the Expiry Date.

"Interest Rate" shall mean 6.16% per annum.

"Promissory Note" shall mean this Amended and Restated Promissory Note.

1.2 Interpretation Not Affected by Headings. The division of the Promissory Note into sections and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of the Promissory Note.

1.3 Extended Meanings. Unless the context otherwise requires, words importing the singular number include the plural and vice versa and words importing gender include the masculine, feminine and neuter genders.

1.4 Invalidity of Provisions. Each provision of the Promissory Note is distinct and severable and a declaration of invalidity or unenforceability of any provision by a court of competent jurisdiction shall not affect the validity or enforceability of any other provision.

1.5 Exercise of Remedies, etc. No delay or failure by the Holder to exercise any right or remedy that it may have against the Issuer under the Promissory Note shall be construed or operate as a waiver of that or any other right or remedy that the Holder may have. No waiver by the Holder of any default by the Issuer under the Promissory Note shall be construed or operate as a waiver of any other or subsequent default.

1.6 Successors and Assigns. The Promissory Note shall enure to the benefit of the Holder and its successors and assigns and shall be binding upon the Issuer and its successors and permitted assigns.

1.7 Governing Law. The Promissory Note is governed by, and shall be construed and interpreted in accordance with, the laws of the Province of Ontario and the laws of Canada applicable in the Province of Ontario.

2. PAYMENT

2.1 Payment Schedule. The Issuer shall pay the Principal Sum to the Holder in instalments as follows: the sum of **TWO HUNDRED AND FORTY-FIVE MILLION, FIFTY-SEVEN THOUSAND, SEVEN HUNDRED AND THIRTY-EIGHT CANADIAN DOLLARS AND SEVENTY-FIVE CANADIAN CENTS** (Cdn$245,057,738.75) (each a **"Scheduled Payment"**) on each of the following dates (each, a **"Scheduled Payment Date"**):

(a) the last Business Day before December 31, 2007,

(b) the last Business Day before December 31, 2009,

(c) the last Business Day before December 31, 2011, and

(d) the Expiry Date.

2.2 Waiver. The Issuer hereby waives presentment, demand, protest or other notice of every kind in the enforcement of the Promissory Note. All amounts owing under the Promissory Note shall be paid by the Issuer without regard for any equities between the Issuer and the Holder or any right of set-off or cross-claim.

2.3 Ranking. The obligations of the Issuer under the Promissory Note are direct, unsecured obligations of the Issuer and rank equally and *pari passu* with all other present and future unsubordinated and unsecured obligations of the Issuer.

3. OTHER

3.1 Event of Default. Upon the occurrence of an Event of Default:

(a) the Holder may declare the outstanding Principal Sum and all interest accrued and unpaid thereon to be immediately due and payable, and the same shall immediately be paid by the Issuer to the Holder; and

(b) in addition to all other amounts payable by it hereunder, the Issuer agrees to pay all expenses incurred by the Holder in endeavouring to enforce its rights under the Promissory Note including, without limitation, reasonable legal fees (on a solicitor and his own client basis) and all such amounts shall bear interest at the Interest Rate.

3.2 No Assignment. The Holder may not, without the prior written consent of the Issuer, negotiate or assign the Promissory Note, in whole or in part, to another person.

3.3 Notices. Any notice or other communication required to be given under the Promissory Note shall be in writing and delivered by hand or sent by facsimile transmission to the party to which it is to be given as follows:

(a) if to the Holder at:

14 Carlton Street
Toronto, Ontario
M5B 1K5

Attention: Chief Financial Officer
Facsimile No.: (416) 542-2676

(b) if to the Issuer at:

14 Carlton Street
Toronto, Ontario
M5B 1K5

Attention: Chief Financial Officer
Facsimile No.: (416) 542-2676

or to such other address or facsimile number as is specified by a party by notice to the other party. Any such notice or other communication shall be deemed to have been given and received on the day on which it was delivered or transmitted or, if such day is not a business day, on the next following business day.

DATED at Toronto, Ontario as of the 1st day of May 2006.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

By: _____

Name: Jean-Sebastien Couillard
Title: Chief Financial Officer

By: _____

Name: Lawrence Wilde
Title: Vice President, General Counsel

DISTRIBUTION EXPENSES OPERATIONS AND MAINTENANCE

INTRODUCTION AND SUMMARY OF DISTRIBUTION OPERATIONS AND MAINTENANCE ("O&M") EXPENDITURES

The Distribution O&M expenditures covered in this exhibit represent all of THESL's expenses to plan, design, schedule, construct, maintain, operate and retire its electrical distribution assets. These costs include the expenditures needed to ensure that designs are developed to appropriate certified standards, that projects and programs for the distribution system are analytically based and sound, that required materials to carry out the projects and programs are available when needed and that necessary vehicles and equipment are available and functional. They also include the operations support expenditures required to perform functions such as housing staff, storing inventory and providing clerical support.

The construction of new electrical distribution plant and the replacement of aging or failed equipment are capital expenditures, which are covered in Exhibit D1, Tab 8, Schedule 1. The costs to maintain and operate existing plant during its useful life, are operating expenditures, which are itemized and explained within this exhibit.

Table 1 depicts both overall maintenance program expenditures and Distribution Capital Program expenditures for THESL. It then compares the aggregation of these costs to the operations support full-time equivalents ("FTEs") for the historical, bridge and test years.

Table 1: Summary of Distribution Costs and FTEs ($ Millions)

Description	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Maintenance Programs[1]	24.1	26.33	28.23	30.45	32.7
Capital Expenditures	140.28	178.83	193.51	203.93	218.63
Total Expenditures	164.38	205.16	221.74	234.38	251.33
Operations Support FTEs	371	371	375	377	376
Throughput ($ work per FTE)	0.44	0.55	0.59	0.62	0.67

Table 1 shows that operations support staffing will remain more or less constant throughout the test years. However, total expenditures are growing significantly year-over-year, attributable to THESL's asset modernization program described in Exhibit D1, Tab 8, Schedule 1. Consequently, throughput (the amount of work completed per FTE, expressed in dollars) rises – that is, every extra dollar of program work requires operations support work to plan, scope, outline, schedule, track, measure, support and administer the program work. As this work will be carried out by the same staff, it represents real efficiency gains. With existing levels of operations support staff, THESL is designing, planning and executing the largest investment program in its history.

SUMMARY OF DISTRIBUTION O&M PROGRAMS

Within the overall O&M cost structure, there are specific operating and maintenance programs which are outlined in subsequent schedules of this exhibit. These programs are based on the same business planning decision principles that drive THESL's capital plans. The Asset Condition Assessment and continuous asset performance monitoring provide a quantitative measure of grid health. The Reliability-Centered Maintenance ("RCM") methodology forms the basis for THESL's maintenance decisions. This

[1] Includes Customer Driven Maintenance

ensures that both capital and operating expenditures are cost-effective and focus on the critical elements of THESL's distribution plant.

THESL's asset maintenance programs are based on the Aladon method of Reliability-Centered Maintenance ("RCM II") described in detail at Exhibit F1, Tab 1 Schedule 2. This methodology is used in conjunction with the Asset Condition Assessment (filed at Exhibit D1, Tab 8, Schedule 9) to determine the optimal maintenance approach (e.g., condition-based or cyclical, inspection or overhaul) for THESL's distribution assets based on their condition and their operating context. When asset replacement is warranted, the associated costs are incorporated into the capital program outlined in Exhibit D1, Tab 8, Schedule 1.

Distribution O&M programs are developed and implemented within the following seven functional areas: Maintenance Programs (Preventive, Predictive, Corrective, Emergency and Customer Driven); Fleet & Equipment Services; Facilities; Procurement; Control Center; Operations Support; and Customer Services. Table 2 provides a summary of THESL's Distribution O&M expenditures for the historical, bridge and test years.

Table 2: Summary of Distribution O&M Budget ($Millions)

Description	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Maintenance Programs	23.90	25.80	27.70	29.90	32.10
Fleet	10.90	11.80	12.70	13.20	14.00
Facilities	24.30	36.70	38.60	39.60	41.00
Procurement	6.61	9.81	9.43	9.71	10.24
Control Center	7.10	6.90	7.10	7.40	7.70
Operations Support	36.90	45.00	48.10	51.30	51.60
Customer Services	41.09	43.00	51.91	55.63	59.19
Total	**150.70**	**178.90**	**195.60**	**206.60**	**215.90**

Distribution expenditures totaled $150.70M in 2006 and are forecast to be $178.90M in 2007, $195.60M in 2008, $206.60M in 2009, and $215.90M in 2010.

Detailed explanations for the year-over-year variances are found in the Tabs and Schedules that follow in Exhibit F1.

In 2007, THESL embarked on an infrastructure modernization and replacement program and began investments that are expected to total $1.2B in electrical plant infrastructure over the next ten years. This work includes rehabilitation of THESL's underground distribution systems, overhead systems, and both Terminal Substations ("TS") and Municipal Substations ("MS"). After an initial break-in period for the newly installed capital equipment, THESL expects to see a trend toward an overall reduction in O&M costs in future years.

MAINTENANCE PROGRAMS

THESL has adopted an asset management philosophy of replacing critical assets based on asset health indices. These indices predict the remaining useful life of the equipment and anticipated maintenance costs. This approach supports the replacement of assets when it is no longer cost effective to maintain them or when replacement is required to protect employee and public safety or the environment. Asset replacements are incorporated into the capital programs discussed in Exhibit D1, Tab 8, Schedules 1 through 3.

When asset replacement is not warranted (i.e., when an asset is within its useful life), maintenance tasks must be performed on the asset to ensure optimal performance, safety and reliability. The Maintenance Program budget funds the detailed planning, design, execution and management required to execute the maintenance programs. Details of the Maintenance Program expenditures are filed at Exhibit F1, Tab 1, Schedules 2 through 6.

FLEET & EQUIPMENT SERVICES

Fleet & Equipment Services ("FES") provides the vehicles and equipment necessary to operate THESL's business efficiently. FES acquires, maintains and repairs the vehicles and equipment required to construct, maintain and operate THESL's distribution system. Details of FES expenditures are filed at Exhibit F1, Tab 2, Schedule 1.

FACILITIES

Facilities Services constructs and maintains THESL's offices, operations centers and transformer station buildings. In addition to capital expenditures for new and renovated facilities (see Exhibit D1, Tab 9, Schedule 2), funds are also required to maintain these facilities in good working order and to provide a safe, functional and efficient work environment for THESL's employees. Details of the Facilities O&M expenditures are filed at Exhibit F1, Tab 3, Schedule 1.

SUPPLY CHAIN

Supply Chain Management forecasts, acquires and distributes the materials supporting THESL's operations. This process ensures that all required goods and services are available when needed while optimizing inventory size and handling costs. Details of the procurement expenditures are filed at Exhibit F1, Tab 4, Schedule 1.

CONTROL CENTRE

Grid Operations is the Control Authority for THESL, and is responsible for the real-time operation of the THESL distribution system from its Control Centre. Grid Operations administers all work protection activities and planned equipment isolations. Grid Operations controls and coordinates the response to system contingencies. The actions of the Grid Response (emergency) crews are directed by the System Operators and Trouble Dispatchers within Grid Operations. Details of the Control Centre O&M expenditures are filed at Exhibit F1, Tab 5, Schedule 1.

OPERATIONS SUPPORT

Operations Support includes the following activities:

- Policy and Standards
- System Reliability
- Capacity Planning
- Operations Administration
- Work Management

Operations Support develops, updates and communicates distribution standards and policies to ensure sound and consistent utility plant design and construction. It also collects data and performs analyses to support investments for system expansion, system enhancements and capital replacement required to improve system reliability. Capacity Planning is required for modernization of station facilities through capacity analysis.

Capacity Planning is necessary to ensure that any expansion or enhancements are made in a cost-efficient manner to support future load growth and reliability of supply. Capacity Planning forecasts are used to ensure that hiring and training of Trades and Technical staff are carried out in a timely manner. Finally, the Work Management group endeavours to improve efficiency and reduce capital and operating costs through centralization of work management and reporting functions and by seeking opportunities for continuous improvement to work processes. Details of the Operations Support O&M expenditures are filed at Exhibit F1, Tab 6, Schedules 1 through 6.

CUSTOMER SERVICES

Customer Services embodies the work activities that are required to provide services to customers connected to THESL's distribution system and to meet the service levels stipulated by the OEB. This group communicates with customers through various means about issues that impact their service and bills. Customer Services addresses all customers including those receiving electricity under the Regulated Price Plan, spot prices and retailer contracts. Customer Services also manages THESL's relationships with retailers.

Customer Services is consists of two main operating areas: Meter-to-Cash and Customer Relationships. The Meter-to-Cash processes include Meter Services, Billing, and Collections, and ensure that meters are safely and correctly installed, accurately read for billing, and accounts are billed and collected in a timely manner. The Customer Relationship processes ensure that all customer inquiries, requests for service and escalated issues are handled in an efficient manner. Details of the Customer Services O&M expenditures are filed at Exhibit F1, Tab 7, Schedules 1 through 6.

DISTRIBUTION OPERATIONS AND MAINTENANCE

MAINTENANCE PROGRAMS

THESL's distribution plant asset maintenance programs are defined in its annual Plant Maintenance Manual. These programs are designed to enable assets to function as originally intended in order to maintain reliability of supply to customers. These programs are derived from the Reliability-Centered Maintenance ("RCM II") methodology discussed below and are developed in conjunction with the Asset Condition Assessment ("ACA") filed in Exhibit D1, Tab 8, Schedule 9.

The ACA and continuous asset performance monitoring together provide a quantitative measure of distribution grid health. When assets have exceeded their useful life and asset replacement is warranted, these replacements are incorporated into the capital programs discussed in Exhibit D1, Tab 8, Schedules 1 through 3. The ACA provides an understanding of the scope of replacement requirements throughout the test years.

Maintenance tasks, on the other hand, are designed to ensure that assets perform optimally while they are within their operational lives. The maintenance programs for the upcoming year are developed using models and assumptions that consider the environment, health and safety laws and regulations, historical failure rates, expected useful life, load, manufacturers' operating and maintenance instructions, insurance underwriters' recommendations and acceptable risk tolerances. The Distribution O&M programs that are scheduled for execution during 2008, 2009, and 2010 are defined in THESL's Plant Maintenance Manual, and have been derived using the RCM II methodology.

MAINTENANCE APPROACH

The Aladon RCM II methodology is designed to establish the optimal maintenance required to achieve a desired level of operational performance from an asset within its current operating context. The key elements are "desired performance" and "operating context". THESL maintains a given asset to perform as needed, based on the way in which it is used. This may mean, for example, that the maintenance recommended by the manufacturer is inappropriate for THESL's purposes. To illustrate, a station circuit breaker may be designed by the manufacturer to operate continuously; as a result, recommended maintenance might revolve around issues like contact wear or arcing damage. However, THESL may operate breakers only a few times a year; consequently, maintenance is more appropriately focussed on switch mechanism seizures due to inactivity. RCM II also provides an understanding of when it is better to replace a given asset, as opposed to performing corrective maintenance tasks to restore operational requirements. This model ensures that investments are cost effective and are focussed on the critical distribution plant elements.

RCM II analyses are based on data from the manufacturer and THESL asset performance records. Where asset performance data is not available, THESL applies the combined experience of the RCM team members to develop a basic approach for an asset class. The RCM analysis teams are comprised of members from Asset Management (Engineering), Grid Operations (Control Authority), and Grid Health (Operations & Construction). The combined experience of these individuals provides a broad perspective on maintenance decisions for those assets where performance data does not yet exist. This initial analysis will be replaced by a quantitative analysis once a statistically significant level of asset performance data has been captured.

The RCM II analysis begins by establishing the functional requirements of each asset. The RCM II analysis then identifies how each asset can fail to perform each function

(termed "functional failures"), the potential causes of these failures (the "failure modes") and the impacts these failures will have ("failure effects"). To illustrate, again consider the station circuit breaker. One of THESL's functional requirements is that the breaker must open to interrupt an overcurrent event elsewhere on the system. One functional failure is that the breaker remains closed. This seizure of the switch mechanism can be due to a lack of lubrication. The failure effects could be damage to the breaker itself, or to equipment downstream of the breaker, with associated customer outages and equipment repair/replacement costs. Once this part of the analysis is completed, the team follows the RCM II methodology through a decision matrix to first determine whether the failure is hidden or evident. The team also uses this model to determine whether there are safety impacts, environmental impacts, operational consequences (e.g., loss of supply to customers) or non-operational consequences (e.g., costs to repair/replace) of the failure. At each step, the team evaluates whether there is a task that can be carried out based on a failure-predicting condition. All decisions are based on technical feasibility and whether the task is deemed to be worthwhile. A task is considered worthwhile if the average annual cost of the maintenance of an asset is less than the average annual cost of the failure over the entire population of the asset; otherwise, the decision criterion is to let the asset "run to failure". Consequently, RCM is designed to determine the least cost maintenance alternative. If, however, safety or environmental considerations are present, the proposed task becomes mandatory, in support of THESL's corporate safety goals and the requirements of environmental, health and safety legislation.

THESL has modified the RCM II methodology to incorporate cost-independent reliability measures like SAIFI and SAIDI. This modification measures the proportional impact of each failure mode on these indices, and overrides a "run to failure" decision if the resultant failure would represent too great an impact on reliability of supply to customers. This approach ensures a good balance between reliability and cost management, effectively optimizing maintenance practices.

MAINTENANCE MODEL

In order to ensure the continued performance and reliability of the electrical distribution system, THESL has developed and implemented a systematic approach to maintenance. THESL conducts four types of maintenance, as follows:

1) **Predictive Maintenance** is the testing or auditing of equipment for a predetermined condition (or conditions) that anticipates failures and then undertaking maintenance tasks to pre-empt those failures. This type of maintenance typically relies on a scientific approach based on actual data; for example, infrared scanning of components can identify incipient failures from elevated temperatures, or sample testing of transformer oil can detect dissolved gasses that occur when components begin to break down. Predictive maintenance is theoretically the least expensive maintenance alternative, but only when a predictive condition can be identified, and practically monitored.

2) Where a predictive condition cannot be determined, or is not practical to monitor, **Preventive Maintenance** is required. Preventive Maintenance typically involves cyclical inspection and maintenance tasks, which emphasize the preservation of asset performance over the expected life of the asset. Maintenance cycles are designed based on the mean time between failures for the failure modes of a given asset class, and are intended to maintain the asset before it is statistically likely to experience the failure. An example of a preventive maintenance task is the inspection of overhead load interrupter switches, which is carried out on a three-year cycle.

3) **Corrective Maintenance** involves repairing or replacing equipment after a failure has occurred and power has been restored through an emergency response; for example, a faulted section of underground cable that had been isolated from the

system during the emergency response would have the failed section unearthed and spliced out under a corrective action. Corrective Maintenance actions may also result from deficiencies discovered during the execution of preventive or predictive maintenance tasks or other planned work. They typically involve a short planning horizon, since a portion of the distribution system is either faulted or isolated, or in a substandard condition thereby putting the distribution system at risk. Corrective Maintenance emphasizes restoring assets to an acceptable level of operation, and hence restoring asset reliability.

4) **Emergency Maintenance** is the urgent repair or replacement of equipment when the equipment fails, causing a power disruption to THESL's customers; for example, replacing a switch fuse link. This type of maintenance may also involve an immediate response to a safety or environmental hazard. It emphasizes safe and prompt restoration of power to THESL's customers.

Table 1: Maintenance Costs for 2006-2010 ($ Millions)

Maintenance Programs	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Preventive	6.30	8.77	8.58	9.03	9.67
Predictive	1.41	1.40	1.45	1.55	1.53
Corrective	9.28	9.04	10.32	11.10	12.10
Emergency	6.91	6.54	7.26	8.21	8.79
Total	23.90	25.75	27.62	29.89	32.10

*Columns may not sum due to rounding

The cost variances for 2006-2010 for each of these programs are explained in the narratives within Exhibit F1, Tab 1, Schedules 3, 4, 5 and 6.

DISTRIBUTION OPERATIONS AND MAINTENANCE

PREVENTIVE MAINTENANCE

Preventive Maintenance is intended to maintain or improve customer service reliability, extend equipment life and ensure employee and public safety. Preventive Maintenance represents the work required to enable THESL's distribution assets to function as specified and to promote continued reliable system performance. This work entails the inspection and overhaul of distribution assets, and replacement of specific components at fixed intervals. Preventive Maintenance is described in this tab, and its program requirements are prescribed in THESL's annual Plant Maintenance Manual. Preventive Maintenance is derived from RCM II, which is designed to determine the optimal maintenance tasks for the assets within their operating context. Optimal in this sense means the least costly maintenance tasks that satisfy reliability, safety and environmental requirements.

As all preventive maintenance programs are derived from RCM analyses, each program represents the most cost-effective alternative for maintaining a specific class of assets. A more frequent maintenance cycle would lead to over-maintaining of assets, and could actually induce failures; a less frequent cycle would lead to more costly failures over time and over the population of the asset.

DISCUSSION

Distribution assets and their components are subject to deterioration and failure over time. Appropriate maintenance practices increases the probability that assets will continue to operate as expected over their expected lives and help protect against major equipment failures and associated reliability problems. Maintenance programs are designed to reflect the fact that asset integrity is influenced by factors such as condition, design, location, age and equipment utilization. Asset deterioration usually manifests itself as a decline in equipment performance, which can negatively impact supply to customers.

THESL maintenance crews are responsible for carrying out, capturing data on and reporting back on various Preventive Maintenance activities as outlined in THESL's Plant Maintenance Manual. The following paragraphs discuss some of the types of equipment and activities that are addressed under preventative maintenance. A comprehensive explanation of all activities is contained in the Plant Maintenance Manual.

Overhead/Underground Distribution

Compact Radial Vaults are inspected twice a year and an inspection checklist is completed to identify any deficiencies. A thermograph is taken of all elbows to identify hot spots and is reported on the checklist. A determination is made as to whether these vaults require power washing and, if so, arrangements are made to schedule this activity.

Network Protectors are overhauled every three years for those with 120/208V supply and every five years for those with 240/416V supply (the differing maintenance frequencies are due to different mean times between failures for the failure modes assessed during the RCM analysis for each protector type). A checklist is completed to verify that the protector was cleaned, relays were replaced, and a function test is performed to verify that loads are picked up automatically. Finally, a "protector card" is signed and placed on the front door of the protector to clearly identify completion of the maintenance.

Three-Phase Gang-Operated Switches are maintained every three years to ensure safe and reliable operation during routine and emergency switching. A Certified Power Lineperson completes a checklist identifying the physical and mechanical condition and verifies the correct blade alignment, blade penetration, travel stops and arc interrupter operation. The switches are then lubricated for efficient operation.

Asbestos inspection is performed to identify areas of the plant that contain material that is considered harmful if it becomes friable. THESL is committed to the prevention of illness

and injury through the provision and maintenance of healthy and safe working conditions on its premises and due diligence in its inspection activities. THESL endeavors to provide a hazard-free environment and to minimize risks by adherence to all relevant legislation, and where appropriate, through the development and implementation of additional internal standards, programs and procedures. The asbestos inspection is mainly to re-examine high risk locations for the presence of friable asbestos and record the findings for future follow-up work. When friable asbestos is discovered the work is issued to a contractor for immediate removal. All non-friable asbestos locations are recorded for future removal.

The network inspection and maintenance program is typically performed in two stages. Initially, inspection and documenting of deficiencies is conducted. Any minor deficiencies are usually repaired during this inspection. Major deficiencies are documented in the Inspection Report for follow-up repairs in the same year as the inspection. Critical deficiencies that pose a safety hazard or impact system reliability are corrected as soon as possible.

Stations

THESL Substations use several different types of Circuit Breakers such as Magnetic Air, Air Blast, Vacuum, Sulfur-hexaflouride (“SF6”), and Oil. Maintenance cycles vary from three to eight years depending on the type of breaker that each substation contains. These units are inspected for leaks, and tests are performed to ensure that they are functioning properly in order to maintain a reliable flow of power to downstream customers.

Carbon dioxide (“CO_2”) and FM200 (Waterless Fire Protection) fire protection inspections are performed every six months to ensure that the intended functions are maintained, and items such as alarms, sensors, and manual electric dischargers are all operating properly.

Power transformer and Primary Load Break Switches ("LBSs") are used to supply the primary load of a power transformer at Municipal Stations with capacity less than 10MVA or at customers' locations. On the 27.6 kV system some LBSs are installed in outdoor enclosures while others are installed in exposed structures. At a customer location, LBSs can be 27.6 kV, 13.8 kV or 4 kV Load Interrupter Switches ("LISs"). The work to maintain these devices includes cleaning insulators, contacts and gears; checking alignment; and performing operational tests.

Stations are another location where friable asbestos can be found. Stations are inspected to identify and record high-risk locations for future follow-up work.

External Contracts

As is detailed in Exhibit C2, Tab 3 Schedule 3, THESL engages a number of external agencies to perform preventive maintenance tasks for several programs. External contractors are engaged to provide these services due to the seasonal nature of the work, and the specialized expertise and equipment required. As an example, insulator washing is required for only two, six-week periods each year. Equipping a THESL crew with a wash truck that only operates twelve weeks per year is not cost-effective because the truck will remain idle for the remaining 40 weeks of the year. As a second example, external forestry contractors are hired for their expertise and experience in tree-trimming services.

Until now the tree-trimming (forestry) program followed a three-year pruning cycle to trim trees in close proximity to overhead lines. This program is aimed at improving reliability by reducing forced outages caused by tree contact. Analysing feeder reliability data for tree contacts in previous years determines the pruning cycle. The feeders having the poorest reliability due to vegetation contacts were given the highest priority for trimming. In 2007, THESL engaged the services of Davies Consulting Inc. to develop a more sophisticated tree trimming model. This model was delivered in June 2007 and is being used to obtain market

pricing and terms for tree trimming work in the years 2008 and beyond. This new tree trimming model is designed to optimize the trimming cycle for each individual feeder.

The washing of porcelain insulators on 27.6 kV overhead line poles takes place in areas where insulators experience extraordinary contamination. Regular pressure washing every six months is performed using clean water to remove contaminants that accumulate over time. Dirt, salt and hydrocarbon deposits, when combined with moisture, reduce insulation levels across line insulators and lead to current leakage (tracking) which can increase over time. This contamination can overcome the minimum insulation requirement of the insulator and lead to a "flash-over". This insulation failure will trip the upstream protective device and cause a forced outage, which ultimately affects reliability.

CO_2 cleaning of pad-mounted switchgear reduces the risk of tracking and, ultimately, switch failure. Switches that are found to be dirty can be cleaned while still energized using CO_2 pellets. Carbon Dioxide is blasted against the switches, releasing the dirt, cleaning the switch, and then evaporating into the atmosphere.

Pressure washing and vacuuming out submersible (underground) transformer vaults keep drains from plugging and prevent exposure of transformers to water, salt, contaminants and other debris. This allows transformers to cool properly and prevents premature rusting.

Table 1: 2006 to 2010 Preventive Maintenance Cost ($ Millions)

Preventive Maintenance Costs	2006 Historical	2007Bridge	2008Test	2009Test	2010Test
OH/UG Distribution Assets	2.23	3.49	2.97	3.15	3.51
Stations Assets	1.92	1.79	2.03	2.22	2.42
External Contracts	2.16	3.50	3.58	3.66	3.74
Total Preventive Maintenance	6.30	8.77	8.58	9.03	9.67

* Columns may not total due to rounding

The total preventive maintenance program cost increased by $2.5 M from 2006 to 2007. This increase is primarily attributable to the addition of a one-time, asbestos audit program and a more aggressive vegetation management program. The asbestos audit accounted for about $900,000 of the increased costs from 2006 to 2007. The Ministry of Labour imposed the asbestos audit program requirement to identify and document all sources of friable asbestos within THESL facilities by the end of 2007.

From 2006 to 2007, external contract costs increased by about $1.6 M primarily due to increased vegetation management program costs. This cost addresses increased tree-related outages, which are described in additional detail at Exhibit B1, Tab 14, Schedule 1. Going forward, the new tree trimming model is expected to optimize the trimming program resulting in reliability improvement due to reduced tree-related outages while maintaining annual spending.

The Preventive Maintenance program is expected to remain constant though out the test years 2008-2010. The cost increases shown in Table 1 are primarily due to the expected inflation for internal labour, vehicles and materials. External contractor costs are expected to follow inflationary trends throughout the period.

DISTRIBUTION OPERATIONS AND MAINTENANCE

PREDICTIVE MAINTENANCE

Predictive maintenance expenditures fund work that is required to test and audit distribution system assets. Predictive maintenance is intended to anticipate equipment failures and to minimize the number and extent of these failures. It relies on scientific methods of testing or inspection that utilize actual data gathered for the purpose of setting performance standards for the asset and its components. Predictive maintenance entails performing maintenance tasks on distribution assets without power interruption to THESL's customers.

Predictive Maintenance is derived from RCM II, which is designed to determine the optimal maintenance tasks for the assets within their operating context. Optimal in this sense means the least costly maintenance tasks that satisfy reliability, safety and environmental requirements. For example sampling transformer oil for the presence of gasses associated with insulation breakdown is technically feasible; however, it is generally only worth doing for larger transformers having a high impact on reliability and resulting in high cost of failure. Predictive Maintenance tasks are identified only where monitoring predictive conditions are technically possible and practical.

DISCUSSION

Predictive maintenance supports THESL's goal of asset modernization by helping to detect future failures. Many failures are related to factors other than asset age, such as breaker component wear, insulation breakdown in power class transformers, or poor intermediate-voltage connections. By testing specific assets against a base reference of a normal condition THESL can determine whether a failure is in the process of occurring. Performing predictive tasks allows the discovery of evidence that assets are approaching failure and provides an opportunity to take action to prevent them from failing

completely. This evidence may also lead to the pre-emptive replacement of a declining asset, either on an individual basis, or for an entire population if a failure mode becomes common throughout an asset class.

The specific asset classes that are included in the predictive maintenance program are itemized and referenced in the latest edition of THESL's Plant Maintenance Manual. These predictive maintenance programs build upon the findings of the ACA performed by Kinectrics Inc., which is contained in Exhibit D1, Tab 8, Schedule 9.

Station Assets

Predictive maintenance tasks for stations assets focus on power transformers and batteries (emergency power systems) located within the stations, and on the station facilities themselves. By performing predictive inspection and testing on these equipment types THESL obtains an advance indication of likely failures. The maintenance of station buildings and property helps THESL secure energised equipment from acts of vandalism or hazards to the public.

Station power transformers are critical links of the power system. Each of them supplies power to anywhere from 800 to 15,000 customers. Transformer breakdowns are usually associated with chemical decomposition of the insulating materials. Such decomposition is detectable by testing for the presence of latent gases, which become dissolved in the cooling oil of the transformer. This analysis of the dissolved gases in the transformer oil is a very important test that is performed periodically to detect incipient insulation faults. The findings from these tests are documented and used to schedule follow-up repairs. Critical or major deficiencies that may affect safety or system reliability are corrected immediately.

All protective relays and control circuits within distribution sub-stations are powered via batteries, which are charged by station rectifiers (charging systems). This source of control voltage is essential for indication lights, alarms and the actuation of equipment such as circuit breakers, SCADA control system, fire protection, and emergency lighting. Failure to maintain sufficient voltage can render the protective system and the breakers inoperative. This may cause damage to electrical assets and the loss of control capability for the entire station. If this occurs, the protection and coordination of the subordinate distribution plant is escalated to the next upstream protective device, such as a breaker from a transmission substation or even a 115 kV breaker in a Hydro One substation. In this event, any potential outage may affect a much larger customer base and physical area. Predictive testing of batteries and charging systems reduces the probability of premature battery failure going undetected, thereby pre-empting potential associated outages.

External Contracts

Infrared and ultrasound scans on station switchgear provide advanced warning of incipient electrical faults. These faults are detected by scanning contact points for signs of overheating, surface tracking and corona.

Beyond sub-stations, most electrical failures originate from loose connections, tracking due to contamination on the surface of insulators, and corona. Infrared and ultrasound scans can be performed while the equipment is in service. These tests detect failures before the component insulation completely fails. Failure has the potential to cause considerable damage to adjacent equipment, potentially long outages and costly repair work.

Load break switches, disconnect switches, and bolted electrical connections are tested before routine maintenance outages so that the problems found during the tests can be

corrected during the routine maintenance outages. Having information about the condition of the equipment in advance of the maintenance outage is a great advantage to the maintenance crews.

Infrared inspection of overhead, three-phase line components identifies potential "hot spots", allowing for corrective measures to be taken before they have an impact on system reliability. Infrared inspection is conducted on all overhead 4.16 kV, 13.8 kV and 27.6 kV three-phase feeders and three-phase distribution circuits. In addition to the overhead line components, any electrical equipment which exists in proximity to these circuits, is also inspected. These inspections are conducted by external contractors annually, typically during the summer peak loading months of July and August.

Pad-mounted switches are installed primarily on feeders (mostly 27.6 kV), and some have connections to more than one feeder. Infrared scanning provides a quick audit of the condition of the live (current carrying) parts and components, including connections and terminations of the switch inside the pad-mount enclosure. They also are visually inspected for signs of contamination build up and tracking. Units with excess contamination build up are scheduled for CO_2 cleaning.

The inspection/maintenance of cable chambers is typically performed in two stages. The inspection and documenting of deficiencies are usually conducted in the summer months using an infrared inspection of the cable splices and digital photographs of all chamber walls. This program is limited to those areas of Toronto containing 27.6 kV cables. These 27.6 kV cables have sufficient fault energy to cause extensive damage within the cable chamber and may cause the chamber lid to become dislodged during a low-impedance fault condition.

THESL uses a ten-year inspection cycle for testing and treatment of its inventory of 159,000 wood poles. The inspection program looks for decay and treats discovered decay in order to reduce the risk of pole failure, thereby enhancing the reliability of the system and public and worker safety.

COSTS

The predictive maintenance program value is derived by focussing on those assets having the greatest impact on the reliability of THESL's distribution system in the event of failure. These assets require extraordinary effort to isolate, and during periods of isolation, leave the distribution grid at an elevated risk of outage. The programs represented in Table 1 for Predictive Maintenance on station transformers, station breakers, critical switches and poly-phase line components are both technically feasible and represent the most cost-effective alternative (as determined through the RCM process).

Table 1: Predictive Maintenance Costs 2006-2010 ($ Millions)

Predictive Maintenance	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
OH/UG Distribution Assets*	N/A	N/A	N/A	N/A	N/A
Stations Assets	1.30	1.15	1.15	1.24	1.22
External Contracts	0.12	0.26	0.30	0.31	0.31
Total Predictive	1.41	1.40	1.45	1.55	1.53

* Costs are included under External Contracts as all work is performed by contractors.

During 2006 and previous years the Stations predictive maintenance program included the thermographic inspection of three-phase, overhead primary feeder circuits and pad-mounted switches. This inclusion was made in order to aggregate similar work and improve efficiency. For 2007 and the test years this work has been outsourced in

combination with the thermographic inspection of cable splices on 27.6 kV underground feeders. Outsourcing of this program accounts for the reduction in cost of the Stations program, and the corresponding increase in scope of external contracts.

During the bridge year and test years the cost of predictive maintenance is affected by minor variations in the volume of work required in each year and the effects of inflationary pressures. The cost for the predictive programs remains relatively flat after adjustments for inflation-driven increases in labour, equipment and contract rates.

DISTRIBUTION OPERATIONS AND MAINTENANCE

CORRECTIVE MAINTENANCE

Corrective maintenance is defined as work required to repair or replace failed assets once power has been restored by Emergency Maintenance efforts. Corrective Maintenance requirements may also result from deficiencies discovered during the execution of preventive or predictive maintenance tasks or other planned work.

Corrective maintenance efforts are designed to restore assets to their normal operating requirements or, where restoration is not possible, to replace these assets. The goal is to ensure that system and customer service reliability are maintained.

DISCUSSION

THESL responds to system component failures on a prioritized basis. Priority considers safety for workers and the general public, outage duration, the number of customers affected, environmental risk and the system contingency limitation imposed by the failed equipment or device. Based on the resulting priority, a response plan is developed and dispatched to appropriate operation crews for the implementation of corrective actions. The crews respond to equipment/ system failures in order of descending priority.

An initial assessment of the failed equipment is performed to determine whether it retains significant residual value and is likely to continue to provide reliable operation. Based on this assessment the crews may:

1) Repair the failed asset, or;
2) Replace the failed asset if it is beyond repair, or;
3) Replace the failed asset in order to improve system reliability and avoid repeated repairs to a device which is at or near the end of its functional life, in keeping with the ACA.

When a repair is completed the failure data is recorded for future performance analysis of the individual asset, the asset class to which it belongs, and the assets string (circuit) with which the failed asset is associated.

OH/UG Distribution Assets

This category includes corrective maintenance work on all of THESL's electrical distribution assets that exist outside of the distribution sub-stations. These assets cover overhead, underground and low-voltage network distribution schemes. System repair tasks are completed by overhead and underground crews.

Station Assets

Corrective maintenance repairs to station equipment are completed on a prioritised basis, using the same considerations as for other distribution assets. Station assets typically occupy the highest priority position due to their hierarchy within the distribution plant. This program includes the corrective repair of failed assets that have caused a forced outage, or have been identified as defective during planned maintenance inspections, or during routine equipment operation. The volume of corrective repairs of station assets is expected to remain constant throughout the test years.

External Contracts

In addition to THESL's planned Tree Trimming program, tree trimming activities also target feeders with poor reliability caused by frequent tree contact interruptions. Vegetation management contractors and internal forestry staff respond to requests made by the System Controller to address immediate reliability problems, or to resolve customer reported problems. Customer calls to THESL's Call Centre regarding tree clearance or related safety issues are dispatched to the Forestry team via THESL's Work Request dispatch team. This program is a reliability improvement initiative aimed at

reducing the frequency of tree contacts that cause both momentary and sustained power interruptions to customers. External contract costs are expected to remain relatively constant after adjustment for annual inflationary increases.

COSTS

In general, corrective maintenance costs can be thought of as resulting from failures due to "run-to-fail" RCM decisions, or from defects found during RCM-based maintenance inspections. In the former case, the run-to-failure decisions relate to asset failure modes for which a planned maintenance approach would be more expensive to undertake over time and over the asset population. In the latter case, the maintenance inspections are carried out at the optimal times defined by RCM. So, corrective expenditure levels are in fact set through RCM based analyses, and are optimal when considered within the overall maintenance approach.

Funding requirements for Corrective Maintenance throughout the test years are shown in Table 1.

From the 2006 Historical year to the 2007 Bridge year, the anticipated spending for corrective repairs was reduced. This constraint in operating expenses was intended to drive an increased focus on asset modernization. THESL's intent is to place increased emphasis on replacing assets that have experienced multiple failures or have reached the end of their reliable service life. These assets are typically replaced with modern, standard equivalent equipment to ensure that safety and reliability are maintained, while operating costs are minimized. In the Bridge year, therefore, THESL is focussing only on high priority corrective work to allow for this increased replacement effort.

Table 1: Corrective Maintenance Costs for 2006-2010 ($ Millions)

Corrective Maintenance Costs	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
OH/UG Distribution Assets	5.54	5.93	6.90	7.44	8.17
Stations Assets	2.38	2.20	2.50	2.74	2.99
External Contracts	1.37	0.92	0.92	0.93	0.94
Total Corrective Maintenance	9.28	9.04	10.32	11.10	12.10

* Columns may not sum due to rounding

However, as the Asset Condition Assessment shows, a number of THESL's assets are at risk of failure and need to be replaced. These replacements are incorporated into the Ten-Year Plan. Nonetheless, it will take ten years to achieve these replacements; in the interim, THESL anticipates that a growing number of corrective maintenance tasks will be required during the test years and beyond. These tasks will start to tail off only in the latter half of the ten-year period. The increase in spending for 2008, 2009 and 2010 is intended to cover this expected growth in corrective work. The expectation is that the new apprentice line staff will come on board to provide some additional labour to support this effort. Consequently, the increase in program cost from the 2007 Bridge year, through the 2010 Test year also includes annual increases in labour, vehicle, and material costs.

DISTRIBUTION OPERATIONS AND MAINTENANCE

EMERGENCY MAINTENANCE

The Emergency Maintenance program funds THESL's first response to system or customer interruption events. These events include system or asset failures, public safety or environmental hazards. THESL's Distribution Grid Response (emergency) crews responded to 71,670 emergency maintenance calls during 2006.

DISCUSSION

Grid Response crews restore power as quickly and safely as conditions allow. These crews also provide information to facilitate the assessment of the incident and the completion of follow-up, corrective maintenance repairs using a System Response Report. A Grid Response – Emergency Maintenance call may result in these typical scenarios:

- The emergency crew is able to restore power and make all necessary permanent repairs. This scenario is typically found in situations such as blown current-limiting fuses, downed service or secondary bus conductors and tree contacts.
- The emergency crew restores power and makes temporary repairs or isolates the problem area or equipment. All customers are restored to full power and corrective maintenance crews perform follow-up repairs, usually commencing the following day. In this scenario, there has usually been a fault on the intermediate-voltage distribution system and the emergency crews are able to isolate the faulted cables or equipment and restore power by transferring load to alternate sources of supply.
- The emergency crew responds to the problem, but is unable restore full power with its resources. In this situation the Standby Supervisor will mobilize the maintenance Standby Crews to support power restoration and corrective repair activities. This often results from broken poles, blown transformers and failed

load interrupter switches. In these cases Standby Crews are called in to augment emergency response resources and complete emergency and corrective repairs or replacement of faulted equipment.

- In the more densely populated urban areas of Toronto, when emergency crews encounter an emergency within the underground plant they report it to the Grid Operations - Control Room. The System Operators from Grid Operations then dispatch underground crews to restore power and perform emergency maintenance repairs. This type of response is common during outages involving the low-voltage, network distribution system, underground vault locations and cable chambers, where larger-scale response is required.
- Standby Crews are mobilised to supplement the response to system or customer interruptions, when the emergency crews are unable to respond in a timely manner. This usually occurs during severe storm events or periods of excessive heat which cause high levels of loading and stress on the distribution system.

COSTS

In general, emergency maintenance costs can be thought of as resulting from failures due to “run-to-fail” RCM decisions. These run-to-failure decisions relate to asset failure modes for which a planned maintenance approach would be more expensive to undertake over time and over the asset population. So, emergency maintenance expenditure levels are in fact set through RCM-based analyses, and are optimal when considered within the overall maintenance approach.

Table 1: Emergency Maintenance Costs 2006 -2010 ($ Millions)

Emergency	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
OH/UG Distribution Assets	6.54	6.26	6.90	7.87	8.41
Station Assets	0.37	0.28	0.36	0.35	0.39
External Contracts	N/A	N/A	N/A	N/A	N/A
Total	6.91	6.54	7.26	8.21	8.79

* Columns may not sum due to rounding

The 2006 historical costs of $6.9 million have been reduced for the 2007 bridge year with a change in the approach to emergency maintenance. During THESL's recent restructuring, its emergency maintenance philosophy was refined to focus more narrowly on those tasks that were immediately related to power restoration. Any repairs that are not essential to the immediate restoration of power are being redirected into THESL's corrective maintenance program.

The overall volume of "normal" emergency maintenance calls received throughout each of the test years is expected to remain stable, at approximately 71,000 calls per year. However, THESL's experience of a number of Major Event Days ("MEDs") in 2007 suggests a trend toward more volatile weather patterns. (As of the end of June 2007, MEDs have occurred on March 1-2, April 23, June 8, and June 19.) During these MEDs, long duration customer outages can occur. To improve response time to outages during MEDs, THESL will be increasing the work force available for extraordinary emergency response, with a resultant increase in overtime costs. This increase, along with general inflation explains the test year increases.

DISTRIBUTION OPERATIONS AND MAINTENANCE

CUSTOMER CONNECTIONS AND MAINTENANCE

Customer Connections and Maintenance ("CCM") is responsible for customer connections, upgrades and enhancements and service cancellations generated by individual customer requests. This exhibit discusses the operating costs associated with these activities. Details of the CCM Capital Program may be found in Exhibit D, Tab 8, Schedule 3-1 "Customer Additions and System Expansion". That exhibit also details CCM responsibilities for executing a portion of the other planned capital programs.

DISCUSSION

Customer-Driven Operations

The work involved in this program is driven by customer requests and is not planned. The funding sought is required to cover expected customer requests for isolations, disconnects and any expensed design cost.

Isolations are usually required to isolate customer equipment from the point of supply, in order to facilitate maintenance of load-side equipment. When an isolation is required by THESL, the customer is not charged if the isolation takes place during THESL's normal working hours of Monday to Friday from 7:30 a.m. to 3:30 p.m. (excluding holidays). THESL does not charge the customer for the first request as so to facilitate and encourage the maintenance of customer-owned equipment. If the customer requests that the isolation be done outside normal working hours, the customer will be charged 50 percent of the associated labour costs.

Disconnects occur when service is no longer required to a property, generally due to a demolition.

Occasionally a customer requesting a connection may cancel the job for various reasons and THESL may have expended some effort in the design of the proposed project. When these events occur, the design cost cannot be capitalized and thus becomes an operating cost to be expensed in the period during which it occurred.

COSTS

The forecast costs for CCM in the 2008-2010 test years along with spending levels for the historical and bridge years are provided in Table 1 below.

Table 1: CCM Customer Driven Maintenance Costs ($000s)

Customer Driven	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Operations	125	513	531	554	588

Funding requirements are estimated based on the expected type of customer events and the labour and equipment expenses associated with those events. The funding requirements for this program in the bridge and subsequent the test years show little change, other than inflationary growth.

FLEET AND EQUIPMENT SERVICES

Fleet and Equipment Services ("FES") provides the vehicles and equipment necessary to operate THESL's business efficiently. FES acquires, maintains and repairs the vehicles necessary to perform electricity distribution operations in a safe and reliable manner.

OBJECTIVES

FES has the following objectives:

- To acquire the vehicles and equipment necessary to operate THESL's business
- To maintain vehicles in keeping with the *Highway Traffic Act* as set out by the Ontario Ministry of Transportation
- To maintain and repair vehicle-mounted equipment used to maintain and construct electrical utility equipment in keeping with regulatory standards
- To manage fleet assets recognizing user needs, availability, licensing requirements, insurance requirements, fuel requirements and the need to maintain departmental tracking and statistics. Vehicle configurations and types are reviewed in June with user groups prior to budget submission to ensure the correct vehicles are available or acquired to meet user demands. All purchases are forwarded through the Supply Chain process with a technical specification as well as review by the Legal Department for purchases exceeding $250,000
- To respond to and repair defective vehicle and equipment assets

ACTIVITIES

FES performs the following activities:

Vehicle and Equipment Acquisition

On an annual basis, THESL evaluates the acquisition requirements of the company in terms of fleet type and quantity. Currently, THESL acquires vehicles and equipment

through either direct purchase from a vendor or through a leasing agreement with a 3rd party lessor.

Vehicle Maintenance and Equipment Maintenance expenses are incurred to:

- Maintain vehicles in keeping with the Ministry of Transportation requirements for the province of Ontario and vehicle manufacturer standards
- Maintain vehicle-mounted equipment in keeping with applicable safety standards, Ministry of Labour standards and equipment manufacturer requirements

Vehicle and Equipment Asset Management expenses are incurred to:

- Maintain vehicle and equipment asset levels to adequately support utility field operations with safe and reliable equipment
- Ensure all vehicles are properly licensed and that adequate fuel resources are available
- Track and monitor vehicle locations and availability
- Budget and track fleet-related costs

Vehicle and Equipment Repair

- Repair defects in vehicles and equipment
- Reconcile vehicle and equipment defect warranty repairs

AFFILIATE VEHICLES

THESL currently owns, maintains and repairs all affiliate vehicles and is also responsible for the acquisition of new vehicles. All affiliate vehicles and equipment are rented by Affiliates from THESL at a monthly vehicle class charge. The calculation of the monthly rate is based on the vehicle costing model explained below. All vehicles, regardless of assignment location are considered together by class to arrive at the average rate per class of vehicle.

VEHICLE COSTING MODEL

FES allocates its costs as it related to FES to the business unit of THESL and to the affiliates based on the cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, FES net budget is neutral after cost allocation (the net costs are included in each business unit or affiliates using the service). Note that vehicles and equipment costs are recovered from user departments based on the number of units by class. Each class of vehicle and equipment type has an applied rate that is based on THESL's costs of acquisition and maintenance. The allocation to affiliates includes a depreciation component for the vehicle and an allowance for return on asset based on THESL-allowable ROE.

FLEET AND EQUIPMENT SERVICES COSTS

Table 1 below presents the FES costs for the historical, bridge and test years. The forecast amounts for 2007 represent a 21 percent increase from historical year 2006 spending. This expected increase is attributable to higher Facilities allocation to accommodate incremental occupancy charges projected in bridge and test years. The use of this return on capital charge commenced in the bridge year (2007). The increase from 2007 to 2008 is based on a forecast increase in vehicle fuel, repairs, licensing and insurance expenses. The increase from 2008 to 2009 is due mainly to increases in payroll, payroll benefits, vehicle fuel and vehicle insurance. The increase between the 2009 and 2010 test years is attributable to vehicle fuel, vehicle repairs and payroll.

Table 1: Operating Expenses for Equipment Services ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
FES Costs	8.11	9.85	11.06	11.59	12.29

Notes:

The costs above have been fully-allocated to business units of THESL or affiliates following our cost allocation model described in Exhibit C1, Tab 4, Schedule 3.

TOOL CRIB SERVICES

Objective

Tool Crib Services has the following objectives:

- Provide hand tools, small equipment and consumables to field staff.
- Repair high-cost or specialized tools that are used by field staff.

Activities

Tool Crib Services performs the following activities:

- Manage the tool crib inventory
- Evaluate new hand tools and small equipment in keeping with continuous improvement of utility practices
- Repair, replenish or arrange repair of high-cost tools

Tool Cost Model

- FES allocates its costs as they relate to tools to the business units of THESL based on the cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, FES net budget is neutral after cost allocation (the net costs are included in each business unit).
- The total tool crib overhead and fixed costs are divided by the total number of field staff that utilize tools and the resulting cost per employee is applied to each department based on headcount.
- The actual cost of hand tools and consumables is charged directly to the budgets of the departments using these items based on forecast use.

Tool Crib Services Costs

Table 2: Tool Crib Operating Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Tool Crib	1.80	0.63	0.55	0.51	0.49

Tool Crib Services operating costs decreased by $1.17M from 2006 to 2007 to reflect the new process of allocating small tools directly to the business units. Between 2007 and 2008 the budget for Tool Crib Services decreased due to a reduction in facilities usage.

LABORATORY SERVICES

Objective

The objective of the THESL Glove/Testing Laboratory ("Laboratory Services") is to ensure that all live line tools are tested in accordance with the requirements of OSHA, EUSA and the Ministry of Labour.

Activities

The following activities are completed by Laboratory Services:

- Clean, inspect and electrically test insulated tools, insulated gloves and line protection;
- Repair and calibrate network system protection relays;
- Repair and calibrate confined space gas monitors; and
- Track and maintain supply of insulated material and gloves.

Laboratory Services Cost Model

FES allocates its costs as it relates to Laboratory Services to the business units of THESL based on the cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, FES net budget is neutral after cost allocation (the net costs are included in

each business unit). The unit costs of specific items, such as gloves and insulated tools, are charged back to the various departments that require these items.

Laboratory Services Costs

Table 3: Laboratory Services Operating Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Glove Lab	1.03	1.29	1.11	1.14	1.18.

FACILITIES SERVICES

INTRODUCTION

Facilities Services provides the real estate and workspace required to operate THESL's business effectively and efficiently. Funds are required to maintain buildings in good working order and provide safe, functional and efficient work environments. Expenditures are made to address only the highest priority facility and equipment needs to conform to safety and environmental standards. Building projects reflect the results of comprehensive evaluations conducted by independent architectural/engineering firms and in-house technical staff. Complementing these comprehensive condition assessments, which are conducted on a five-year cycle, are annual condition surveys conducted by THESL maintenance and operations staff. The surveys are checklists to detail problems, deficient conditions, and maintenance needs at sites, buildings and other structures. These include drainage, site circulation, utilities, building structural frame and foundation, roofs, plumbing systems, heating and air-conditioning systems, electrical systems, fire emergency systems and interior finishes.

OBJECTIVES

Facilities Services must provide cost effective, safe, functional and efficient work environments to positively impact productivity and human performance. Properly designed, configured and maintained work environments are necessary to allow work to be accomplished in a safe and efficient manner. Supporting a dynamic workplace that encourages employees and drives business results is the overriding objective of the Facilities Services function.

ACTIVITIES

Facilities Services provides the following ongoing services for Toronto Hydro's facilities:

- Routine maintenance

- Preventive maintenance
- Office services
- Housekeeping service
- Landscaping maintenance

Facilities Management maintains design standards and facilitates the procurement of systems furniture and ancillary furniture. Facilities staff work with individuals and departments to assess, document and plan for workspace modifications needed to address changes in business processes or personnel deployment. Facilities staff assist in identifying and developing workplace standards, eliminating barriers to optimum human performance, supporting collaboration, enhancing the use of technology and meeting individual needs for privacy. Once a modification plan is developed and approved, Facilities staff manage the physical modifications to work spaces including planning, scheduling, procurement, move management and complete installation oversight.

Facilities Management also provides design and construction management and consultant/contractor management services through its technical staff, for building alternations. These services include facilities needs analysis, programming, design, consultant/contractor procurement and complete construction management.

OCCUPANCY COSTING MODEL

The Facilities group allocates its costs to the business units of THESL or the affiliates based on the cost allocation model described in Exhibit C1, Tab 4, Schedule 3. The occupancy charge is a per-square-foot charge used to allocate facility-related costs to users. The underlying principle is to follow commercial practice that closely approximates how landlords transact business with tenants regarding contract rent. The occupancy charge includes all costs related to the on-going operation and maintenance of facilities.

Costs are developed based on an annual review of user allocation of space. Each year the following process is undertaken to establish the space allocation budget:

1) Review previous year program input and make necessary revisions (Budgets, Space Inventories, and other inputs)
2) Establish allocation rates for applicable space types (Office, Warehouse, Yards)
3) Generate unit and subunits space assignments
4) Submit to management for approval

The allocation to affiliates includes a depreciation component and the return on asset component based on the THESL-approved ROE.

FACILITIES SERVICES COSTS

Facilities costs are driven by the formation and disbanding of work groups to support business activities. Our work environments need to be flexible to enhance communication amongst employees, improve efficiency and productivity and continually respond to organizational changes.

Table 1: Facilities Maintenance and Operations Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Costs	24.30	36.70	38.60	39.60	41.00

Table 1 presents the costs for the historical, bridge and test years. Costs drivers include payroll, transportation, materials, utilities, taxes and external purchased services. The cost increase from 2006 to 2007 is primarily due to the addition of two short-term leased facilities, Monogram Road and Milner Road, and the continued costs associated with 28 Underwriters Road while it is being decommissioned and prepared for disposal. In addition to general escalation, the cost increase from 2007 to 2008 is due to primarily to

the inclusion of a full year's occupancy costs for the Milner facility, which had a projected occupancy in mid-2007. For 2009 and 2010 cost increases are based on general escalation.

The Facilities costs included above are allocated to all the business units of THESL and to affiliates based on usage of space and following our cost allocation model described in Exhibit C1, Tab 4, Schedule 3. Accordingly, Facilities costs are neutral after allocation as each business unit carries its portion of Facilities costs (the costs shown above are before allocation).

PROCUREMENT

INTRODUCTION

Supply Chain Management supports THESL's asset management strategy by ensuring that all required goods and services are available when needed, while at the same time optimizing inventory size and handling costs. The Supply Chain operations are key to ensuring that the $81.2M in catalogued materials forecast for use in 2008 are ordered and delivered in a cost effective and efficient manner.

SUPPLY CHAIN CORE STRATEGY

- Provide an uninterrupted flow of required materials, supplies and services
- Keep inventory investment and loss to a minimum
- Maintain and improve quality of materials
- Find or develop competent suppliers
- Standardize, where possible, the items and services bought
- Purchase required items and services at lowest total cost
- Accomplish the purchasing objectives while minimizing administrative costs

SERVICES

- Procurement
- Sourcing
- Purchasing Research
- Vendor Management
- Inventory Control
- Transportation
- Asset Disposal
- Forecasting and Planning

- Outsourcing and Subcontracting
- Warehousing/Storage/Materials Handling/Logistics

Supply Chain Centralized Structure provides for:

- Greater buying specialization
- Consolidation of requirements
- Coordination and control of policies and procedures
- Effective planning and research
- Common suppliers
- Critical mass
- Strategic focus
- Low cost of purchasing

KEY INITIATIVES

Supply Chain Management regularly reviews performance metrics and operating costs to ensure service expectations are met and budgets are adhered to. Supply Chain has implemented a number of key initiatives to improve operational processes and efficiencies such as the Business Requirements Planning ("BRP") model which aligns operational planning, scheduling, supply and construction operations by applying an integrated planning process approach to balance supply and demand of materials, resources and equipment. BRP has resulted in increased order fill rates, improved inventory turns, improved SKU accuracy, reduced materials lead times, reduced overdue shipments and improved supplier delivery performance.

ACTIVITIES

Supply Chain is structured under three main functional areas:

1) Acquisition of Goods and Services
2) Demand Management
3) Warehouse and Logistics

Acquisition of Goods and Services

Acquisition of Goods and Services refers to the purchase of all electric distribution material required to build and maintain the electric distribution system including transformers, poles, wire and cable and miscellaneous items (e.g., tools, safety equipment, clothing, and consumables). In addition, it refers to the purchase of all non-electric goods and all services, required by the various business units to conduct everyday operational activities (e.g., IT software and hardware, furniture, vehicles, stationery, printed matter, building maintenance contracts, civil construction contracts, consulting agreements and leasing agreements).

Typical activities associated with this service are:

- Administration of competitive bidding processes
- Vendor sourcing and assessment
- Establishing requirements for tenders, RFP, and RFQ
- Evaluating proposals and awarding contracts
- Developing strategic supply/service agreements
- Processing Purchase Orders
- Providing reporting to the business units and Executive
- Ensuring adherence to the Procurement Policy
- Developing supplier alliances and maintaining supplier diversity

Acquisition Services costs are recovered through a cost allocation program administered through the Finance Department as described in this exhibit under the heading "Cost Allocation Program".

DEMAND MANAGEMENT

Demand Management performs all activities involving inventory materials including statistical analyses, management of inventory stock levels, re-order analyses, managing the cycle count process and the disposal of all surplus and obsolete material.

The major Demand Management activities are:

- To maintain a perpetual inventory system to ensure that the inventory levels are determined via accepted inventory control techniques and algorithms which minimize the occurrence of out-of-stock inventory and work schedule delays;
- To monitor and report corporate wide inventory transactions with the purpose of developing and maintaining appropriate performance measurement criteria. Key Performance Indicator ("KPI") metrics have been established for inventory turns, inventory SKU accuracy and inventory fill rate;
- To develop and implement inventory classification criteria for better in-depth analysis of the inventory;
- To establish a daily inventory cycle count program and report cycle count performance, reconcile inventory variances, conduct root-cause analysis and maintain supporting documentation;
- To identify and maintain records of slow- and non-moving inventory for disposal;
- To provide inventory planning and management, disposal of surplus and obsolete materials and coordination of risk management activities related to supply chain;
- To forecast inventory requirements and collaborate with internal customers and vendors to minimize inventory levels; and

- To continue to build long term supply agreements and strategic alliances for most inventory items.

WAREHOUSING & LOGISTICS

Warehousing & Logistics receives, stores and issues all inventory materials for both capital projects and maintenance requirements. Material is distributed to field crews from three warehouse locations.

The major activities associated with this service are:

- To pick, stage, and load electric distribution material onto fleet vehicles;
- To unload, inspect, receive, and store electric material from vendor vehicles;
- To deliver and pick-up materials to and from the job sites and other warehouses;
- To issue miscellaneous (over-the-counter) items such as tools, clothing and safety items); and
- To perform daily inventory cycle count activities.

COSTS

Table 1: Supply Chain Costs ($ Millions)

Departments	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Whse/Demand Mgt/Admin	5.21	8.55	7.86	8.10	8.51
Acquisition Services	1.40	1.26	1.57	1.61	1.73
Total	6.61	9.81	9.43	9.71	10.24

The 2007 Supply Chain budget has increased by about $3.2M over 2006 actual expenditures. The expansion of warehouse storage facilities required to support the

increased capital and maintenance programs over the next five-year period accounts for about $1.6M of the increased costs. This is a short term facilities requirement; over the longer term THESL plans to reduce the overall storage facilities and costs by consolidating facilities as described in the Facilities Plan contained in Exhibit C2, Tab 2, Schedule 1. The remaining $1.6M in budget increases is primarily attributable to the following:

a) general increases in payroll costs;
b) additional materials-handling equipment and related Fleet maintenance costs;
c) internal labour services costs charged to Supply Chain (i.e., testing and repairs to network protectors and transformers); and
d) transformer reclaim refurbishment costs.

Most aspects of the Supply Chain costs for 2008 through 2010 are projected to remain stable or increase by 2-2.5 percent per year, in line with the forecasted CPI indices.

Cost Recovery

The Maintenance and Operations costs are fully recovered from user departments through the use of the inventory on-cost rate and the cost allocation cost-recovery programs.

Inventory On-cost Rate

The costs associated with operating the warehouse, general administrative and demand management functions are recovered through a materials on-cost recovery program which is applied to the cost of inventory materials at time of issue. The current on-cost rate for 2007 inventory is 10.04 percent. This amount is applied to the cost of each item issued from inventory. Supply Chain has focused its efforts over the past five years on significantly reducing overall operating costs in both the Warehouse and Demand Management areas through a combination of staff reductions, efficiency improvements and lower operational costs. Operational cost reductions have resulted in a 71 percent

reduction to the inventory on-cost rate over the past five years. Additional costs for warehouse storage facilities required to support the increased capital and maintenance programs over the next five-year period will cause the on-cost rate to rise, but even with these increases, the rate will remain well below 2006 levels.

Table 2: On-cost rate (%)

Year	2003	2004	2005	2006	2007
On-cost rate	35	19	19	15	10

Cost Allocation Program

Acquisition Services costs are recovered through a cost allocation program which re-allocates the costs based on the percentage of purchase orders transacted by each user department.

DISTRIBUTION GRID OPERATIONS

INTRODUCTION

Distribution Grid Operations ("DGO") is the control authority for THESL, and is the real-time operator of THESL's distribution system. THESL has a single Control Centre, which is located at the 5800 Yonge Street site. From this location DGO staff coordinates and monitors the distribution of electricity across THESL's service territory. This Control Centre is linked to THESL's distribution assets via a digital network providing both voice and data communications. THESL utilizes Supervisory Control and Data Acquisition ("SCADA") systems to monitor its distribution system. SCADA systems are used extensively to monitor and operate the 27.6 kV and 13.8 kV primary feeders.

DISCUSSION

DGO has two primary responsibilities: to maintain real-time control of THESL's distribution plant and to coordinate all activities involving workers within the "safe limits of approach" to THESL plant that is energized above 750 Volts.

The portion of THESL's distribution plant under the direct control of DGO Operators includes all intermediate-voltage equipment and cabling normally energized at 4 kV, 13.8 kV or 27.6 kV. This real-time control includes the monitoring of grid operation, system loading and the response to system or asset failures.

Under normal operating conditions Distribution Grid Operations works to prepare and execute "Orders to Operate" system devices, enabling planned capital and O&M activities for THESL's workforce. These "orders to operate" each comprise a list of switching instructions which enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices. This

work protection enables crews to work in accordance with applicable safety legislation and protects the security of supply to THESL's customers.

During abnormal system conditions, which are typically caused by storm activity or heat stress to distribution assets, the System Controllers coordinate THESL's response to these system contingencies. In extreme cases, as witnessed during the period of March 1-5, 2007, the System Controllers support the real-time administration of THESL's Emergency Preparedness Plan. The System Controllers and Trouble Dispatchers within Grid Operations direct the response efforts of THESL's Grid Response (emergency maintenance) crews during system contingencies and abnormal conditions. Please refer to Exhibit F1, Tab 1, Schedule 6 for details of emergency maintenance activities.

Supporting the System Controllers is a staff of technicians and clerical support workers that analyse Grid Performance data for the purpose of determining areas requiring reliability or performance improvement. The staff uses Interruption Tracking Information System ("ITIS") data to determine the cause of system failures and aggregate related failures. These data are then further analysed by Asset Management engineers and staff to develop mitigating actions and improve system safety and customer service reliability.

COSTS

As THESL's work program grows throughout the bridge and test years, there will be a greater amount of Grid Operations work to support its execution. Each capital construction project or maintenance task requires time for activities such as developing Orders to Operate, crew dispatching to perform the switching and the acquisition of work permits to provide a safe work zone. Given that Distribution Grid Operations staffing will remain flat, each staff member will be required to increase throughput to meet THESL's work program demands. This represents a year-over-year efficiency gain.

Table 1: Distribution Grid Operations Costs ($Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Distribution Grid Operations	7.10	6.90	7.10	7.40	7.70

The costs for Distribution Grid Operations' Control Centre activities are almost exclusively comprised of labour resource costs. These costs remain flat to the 2008 test year. From 2008 to 2009 THESL is projecting an annual increase of 2.9 percent as well as a further 3.4 percent increase from 2009 into 2010. These increases reflect escalation in labour costs and inflation.

OPERATIONS SUPPORT SUMMARY

INTRODUCTION

The evidence presented in Exhibit F1, Tab 6, Operations Support, is an overview of the support costs necessary for THESL to provide safe and reliable electrical distribution services. The Operations Support submissions include the following:

- Policy and Standards
- System Reliability
- Capacity Planning
- Operations Administration
- Work Management

Table 1 shows a summary of the funding requirements for each of these areas. Each function is addressed within the company's evidence.

Table 1: Operations Support Costs ($ Millions)

Operations Support Program	2006 Historical**	2007 Bridge	2008 Test	2009 Test	2010 Test
Policy & Standards	2.73	3.29	1.69	1.74	1.77
System Reliability	5.52	2.53	1.68	1.72	1.74
Capacity Planning	3.75	3.74	2.00	2.06	2.10
Operations Admin	22.30	29.54	32.53	32.88	33.59
Work Management	2.60	5.90	10.20	12.90	12.40
Total Operations Support	36.90	45.00	48.10	51.30	51.60

**This area was substantially reorganized in 2007. Thus, the allocation of total cost among departments for 2006 is an estimate.

Policy and Standards

The Policy and Standards Department conducts the analyses needed to develop and update standards and policies, and communicates these throughout THESL. The on-going development of and revisions to standards and policies ensures that THESL is constructing and maintaining its assets in an efficient, modern and safe manner in order to maintain reliability. Policy and Standards also undertakes the preparation of material and labour and vehicle compatible units to ensure cost effective preparation of construction design estimates. The Policy and Standards activities and funding requirements are described in Exhibit F1, Tab 6, Schedule 2.

System Reliability Planning

System Reliability Planning focuses on the collection of data and preparation of analyses to support investments for system expansion, system enhancements, and capital replacement required to improve system reliability. This area also conducts maintenance planning to determine the most cost effective maintenance programs to allow THESL to maintain reliability and safety. System Reliability Planning undertakes studies such as the Asset Condition Assessment ("ACA") to determine where future distribution capital investment will be required. It also analyzes feeder loads to determine future grid expansion projects. Exhibit F1, Tab 6 Schedule 3 describes the funding requirements and program functions for System Reliability Planning.

Capacity Planning

Capacity planning is required for modernization of station facilities through capacity analysis. The Capacity Planning Department ensures that any expansions or enhancements are made in a cost-efficient manner to support future load growth and ensure reliability of supply. This Department also undertakes on-going coordination of THESL's activities with Hydro One and the Ontario Power Authority plans. Capacity

Planning is also responsible for system records management and is the contact for any new generation connection to THESL's distribution system. Exhibit F1, Tab 6, Schedule 4 describes the Capacity Planning functions and the funding requirements.

Operations Administration

The Operations Administration Department is responsible for expenditures to support the workforce required to accomplish the annual capital and operating programs. The costs incurred in this area include labour support such as supervision and administrative staff, office equipment and communication expenses (such as cell phones and radios). Training and safety meeting expenses are also captured in this area, as are expenses for small tools, clothing, meal allowances and other administrative costs. A detailed description of the activities and funding requirements in this area can be found in Exhibit F1, Tab 6, Schedule 5.

Work Management

The work management program is part of THESL's commitment to continuous improvement. This program is designed to help improve efficiency and reduce capital and operating costs through centralization of work management and reporting functions and by seeking opportunities for continuous improvement in work processes. Details of these efforts and the associated funding requirements may be found in Exhibit F1, Tab 6, Schedule 6.

OPERATIONS SUPPORT

POLICY & STANDARDS PLANNING

The objective of Policy & Standards Planning is to develop distribution standards and policies that drive the efficient execution of utility asset construction and maintenance activities, in order to promote safety and reliability. It develops utility standards and policies based on an asset life cycle analysis that optimizes investment, manages utility risks, and achieves business strategies and performance objectives. Other responsibilities include coordination between THESL and the City of Toronto, external relations work including execution of Offer to Connect Contracts, management of infrastructure, use of THESL infrastructure by others, and the co-ordination of unplanned non-connection emerging projects.

ACTIVITIES

Policy & Standards Planning encompasses three main functions: Standards Planning, City Coordination and Policy & External Relations.

Standards Planning

Standards Planning prepares specifications for the materials used in THESL's electrical distribution system, and updates construction standards to incorporate the latest materials.

Activities

- Develop, update, and effectively communicate construction standards that are consistent with business strategies and performance
- Prepare and maintain materials, and labour and vehicle Compatible Units that are used to prepare more accurate and consistent project estimates. Compatible Units refer to a defined group of materials or labour and vehicles used as the basis for project estimates

- Prepare equipment and material specifications to allow for system improvements
- Investigate equipment and materials deficiencies, where materials do not meet specifications; determine causes of substandard performance; make recommendations and implement remedial actions to enhance system performance
- Evaluate new equipment and materials, conduct pilot field trials and assess economic impacts on inventory and on construction costs, of the adoption of new equipment and materials
- Manage the materials catalogue through SKU harmonization (consolidating several material types into one), additions, deletions and changes to specifications. Work with Procurement to optimize stock and inventory levels
- Obtain feedback from project designers and field staff and adjust Compatible Units, and make standards and materials changes as required to ensure standards and construction practices are up-to-date

City Coordination

City coordination involves coordinating THESL long term plans with those of other utilities, the Toronto Transit Commission ("TTC"), and the City of Toronto ("City"). Also, THESL identifies its underground and overhead infrastructure on other utilities' drawings, to co-ordinate with their short-term construction plans.

Activities

- Provide a "mark-up" of THESL's overhead and underground infrastructure on City, other utility and customer drawings, so as to avoid conflicts with THESL's existing and proposed plant, and allow cost-effective coordination with the installation of other utility and customer infrastructure

- Participate in the Toronto Public Utilities Coordinating Committee, which seeks the cost efficient co-ordination of THESL's annual and multi-year capital work plans with those of the City, other utilities, and the TTC
- Review the payment of cut permits from the City, which are invoices for City repairs to city pavement and sidewalks that are required when THESL underground or overhead infrastructure is installed on City-owned property
- Coordinate with the City or other utilities on major projects that will have impact on THESL's existing or proposed plant or programs to avoid potential conflicts

Policy & External Relations

Policy & External Relations works with external customers and internal departments in matters of policy development and maintenance. It is responsible for negotiating "Offer to Connect" documents with new customers, and for coordinating the duct and pole rentals with external customers.

Activities

- Prepare and execute "Offer to Connect" contracts for new customer connections
- Administer capital contributions, expansion deposits, and "Offer to Connect" settlements
- Prepare scope packages for emerging-issue projects arising from external sources including customers, city road improvements and Business Improvement Associations and Councilor requests
- Co-ordinate the removal of other entities' (e.g., Bell, Rogers and TTC) equipment from THESL's poles and infrastructure as a part of THESL's capital programs
- Prepare duct and pole rental agreements and invoicing
- Develop and maintain policies including the Conditions of Service
- Respond to customer, public, regulator and other inquiries on matters related to utility distribution assets

- Develop and maintain strategic partnerships, business relationships and alliances with industry stakeholders and service providers and participate in industry organizations and associations

COSTS

While staffing and associated costs remain relatively flat throughout the test years, the work program continues to grow year-over-year. Consequently, a greater amount of work related to obtaining permits and coordinating work with the City and TTC will be undertaken by each staff member each year. This higher throughput represents an efficiency gain expected in each year.

Table 1: Standards and Policy Planning Costs ($ Millions)

Year	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Costs	2.73	3.29	1.69	1.74	1.77

In 2007, a major corporate reorganization was undertaken to better align the people with the processes so as to ensure their expertise was deployed for maximum benefit. This reorganization of staff between departments has caused the Standards and Policy payroll budget to increase from the 2006 budget; however, this is partially offset by an increased allocation of engineering expense to capital.

From the 2007 bridge year to the 2008 test year, additional engineering administration charges are allocated to capital, along with additional labour cost recoveries that were not budgeted in 2007. This explains the reduction in 2008 budget costs from 2007.

OPERATIONS SUPPORT

SYSTEM RELIABILITY PLANNING

System Reliability Planning prepares plans to improve system reliability. This includes determining the most cost effective capital replacement programs, as well as maintenance programs for each asset type through a "Reliability Centered Maintenance" approach. Distribution feeder plans are optimized considering:

- new loads;
- asset condition;
- cost effective routing;
- system reliability; and
- automation opportunities.

System studies, such as the ACA, pinpoint key areas where future asset investment is required. Grid expansion projects are also identified through the analysis of system feeder loads.

ACTIVITIES

System Reliability Planning involves three main functions described below.

Feeder Reliability

Feeder Reliability incorporates the following activities:

- Review feeder loading and pinpoint performance gaps
- After considering all alternatives, prepare feeder rearrangements as required to accommodate new customer loads
- Address customer concerns regarding system and/or feeder performance by investigating the cause of the concern and, as necessary, increasing maintenance inspections or generating capital projects to address the issue

- Work in collaboration with the City of Toronto, Hydro One, and the TTC; to generate and co-ordinate work on specific projects including addressing any conflicts so as to reduce cost and increase efficiency
- Identify demand capital projects to improve THESL system performance and address issues, such as reliability, safety, and compliance with regulatory and environmental requirements
- Prepare capital project plans and scope packages by validating system records, developing high level estimates, performing risk analyses, conducting site visits, and producing a detailed description of the work required
- After reviewing all alternatives, complete scope packages and issue them for design and construction
- Create the annual THESL capital budget, based on prioritizing financial, plant modernization, safety, workforce development and reliability considerations
- Continue refining the ten-year plan, to ensure system performance is maintained and improved

Component Reliability

Component Reliability incorporates the following activities:

- Develop annual maintenance programs, and prepare THESL's annual Plant Maintenance Manual
- Prepare annual budget for all maintenance projects, to ensure system performance is maintained and improved
- Review asset inspection data using RCM analysis to determine health and age profile of equipment to optimize inspection schedules
- Recommend program adjustments to optimize maintenance programs
- Perform reliability studies to improve SAIDI and SAIFI using THESL's Interruption Tracking Information System ("ITIS") and equipment failure analysis reports

- Use data in the Ellipse asset registry to optimize inspection schedules by generating Maintenance Schedule Tasks ("MST") for each individual major asset in Ellipse. Ellipse is THESL's Enterprise Asset Management ("EAM") system used as a central data source, to schedule projects and to manage material inventories. MSTs will generate the Work Orders for the crews that execute the work. Inspection results including failures or deficiency information gathered from the field are entered back into Ellipse against the particular equipment. This information can then be used for future trending or failure analysis
- Award contracts and prepare specifications for contract work

System Expansion

System Expansion incorporates the following activities:

- Analyze system reconfigurations to accommodate customer requests for new load and to optimize utilization of system assets
- Optimize system feeder loading performance through feeder load forecasting and transfers
- Prepare the feeder master plan, to accommodate future growth in a cost-effective manner, while optimizing system capacity, and considering automation opportunities
- Establish planning guidelines such as cable sizes and feeder routing, to ensure consistency of design and optimum system performance, and to achieve cost effective implementation
- Forecast feeder loads, to pinpoint future improvement opportunities, through the use of spreadsheets and automated tools such as the PI Process Book and Network Gird Calc Programs
- Work with customers to address Power Quality performance issues
- Perform engineering studies to identify assets requiring modernization

- Review new technologies to enhance system performance in a cost-effective manner

SYSTEM RELIABILITY PLANNING COSTS

While System Reliability Planning staffing and its associated costs remain relatively flat throughout the test years, the work program continues to grow year-over-year. Consequently, a greater amount of work in planning and developing reliability improvement projects will be undertaken by each staff member each year. This higher throughput represents an efficiency gain expected in each year.

Table 1: System Reliability Planning Costs ($ Millions)

Year	2006 Historical**	2007 Bridge	2008 Test	2009Test	2010Test
Costs	5.52	2.53	1.68	1.72	1.74

**The 2006 actual spending was based on the former organization

The actual 2006 costs shown are for the former Investment Planning Department and the Asset Data Management Departments that were restructured in January 2007. The re-organization more closely aligned Asset Management departments with the objectives of improving system reliability, modernizing the assets and improving customer focus.

The decrease in costs from 2006 to 2007 is attributable to the transfer of only a portion of the staff from the former Investment Planning Department to System Reliability Planning. The remaining staff were deployed to other areas.

The decrease from 2007 bridge year to the 2008 test year is due to an increased allocation engineering costs from operating expense to capital expenditures and a reduction in contract charges in 2008. Net operating costs then remain relatively flat for the remainder of the test years.

OPERATIONS SUPPORT

CAPACITY PLANNING

The main function of Capacity Planning is to plan for the modernization of station facilities through a detailed capacity analysis of THESL's system. Based on this analysis, grid supply plans are created to ensure sufficient transmission, station and feeder capacity. Using these plans, THESL expands capacity in a cost efficient manner to support future load growth and reliability of supply in order to meet the needs of the City of Toronto, Canada's largest city and financial capital. THESL coordinates its plans with Hydro One Networks Inc. ("HONI") and the Ontario Power Authority ("OPA") to ensure sufficient transmission capacity for Toronto and alignment with the short- and long-term plans of those entities.

Capacity Planning also performs a number of other functions. It facilitates connection of new generation to THESL's System. It also keeps system records current in support of the design of new infrastructure installations and to allow troubleshooting during emergencies. Finally, the Capacity Planning Department prepares the maintenance investments for 230 terminal (TS – generally owned by HONI) and municipal (MS – owned by Toronto Hydro) stations using the Aladon RCM II methodology, as well as the data management features of THESL's Ellipse Enterprise Resource System Planning ("Ellipse"). Ellipse is used as a central data source, to schedule projects and to manage material inventories.

ACTIVITIES

Capacity Planning incorporates the functions described below.

Records Management

Record Management undertakes the following activities:

- Update web-based records used by field crews, from "as constructed" construction drawings into the Ellipse and Geo-Electric mAppring Records ("GEAR") databases. GEAR stores asset plant information on maps, facilitating easier design, and improved system operation
- Update and circulate the operating prints of system feeder information used by THESL crews to reflect changes to infrastructure, in order to ensure safe and efficient system operation
- Perform field visits to verify construction information
- Maintain corporate records such as vault files that detail the electrical infrastructure present in customer locations
- Co-ordinate with the City of Toronto to obtain updates of the city land-base records, to ensure efficient design and operating processes
- Prepare city-wide maps of infrastructure replacement programs, which are aligned to THESL's ten-year capital plan, for internal and external circulation

Asset Data Management

Asset Data Management undertakes the following activities:

- Update Ellipse equipment registry with information on distribution assets using Webview (a web-based mapping product used to display electrical infrastructure for designers and field crews) and GEAR
- Review information from scheduled maintenance inspections performed by field crews as input to maintenance and capital replacement decisions
- Perform field audits to review asset condition based on inspection reports
- Automate the collection of field inspection data through the use of Mobile handheld devices, which increase the efficiency of data collection and reduce operating costs
- Set up and optimize maintenance schedules through Ellipse and asset condition monitoring data to reduce operating costs and improve equipment reliability

- Prepare web-based reports to monitor asset conditions

Station Planning and Performance

Station Planning and Performance undertakes the following activities:

- Prepare station five-year and 25-year load forecasts and identify station expansion projects to modernize assets so as to ensure reliable system performance
- Develop annual plans for stations capital programs and assist with planned maintenance programs to modernize station assets
- Co-ordinate THESL's station projects with HONI's station projects
- Review inspection data to identify station equipment as inputs to maintenance and capital replacement decisions
- Prepare business cases to compare alternative scenarios for station expansion projects.
- Facilitate the connection of generation onto THESL's electricity distribution system
- Review and provide, where required, relay and protection co-ordination settings for station breakers at the request of HONI and customers
- Review and modify system emergency preparedness plans

CAPACITY PLANNING DEPARTMENT COSTS

While the Capacity Planning staffing and its associated costs remain relatively flat throughout the test years, the work program continues to grow year-over-year. Consequently, a greater amount of work, in developing station modernization projects and keeping records current, will be undertaken by each staff member each year. This higher throughput represents an efficiency gain expected in each year.

Table 1: Capacity Planning Costs ($ Millions)

Year	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Costs	3.75 **	3.74	2.00	2.06	2.10

** This is an estimate. Capacity Planing did not exist in the present form in 2006.

Staff was transferred from the Investment Planning Department to the new Capacity Planning Department in January 2007. The costs associated with this staff in the 2006 Historical year are included in Exhibit F1, Tab 6, Schedule 3.

The decrease from 2007 to 2008 in the Capacity Planning Department budget is due to additional engineering administration costs allocated from expense to capital.

OPERATIONS SUPPORT

OPERATIONS ADMINISTRATION

Operations Administration expenditures are the costs incurred in support of the annual Capital and Operating programs. The costs in this area include the labour to support the programs, as well as the tools and clothing required by the field staff, communications equipment and other employee expenses such as transportation and meals. Office expenses, training, safety meetings and employee participation on various workplace committees are also included in these costs.

OPERATIONS ADMINISTRATION COSTS

The Administrative costs incurred in support of Distribution Operations are shown in Table 1 with the proposed funding for Test Years 2008-2010, as well as spending levels for Historical and Bridge years.

Table 1: Operations Administration Costs ($ Millions)

Description	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Costs	22.30	29.54	32.53	32.88	33.59

Administration costs, including all allocations, rose from the historical year 2006 to the bridge year 2007 due to general increases in inflation and payroll and vehicle changes due to the reorganization. Changes in staff level also increased support costs, including communication equipment, office supplies and other incidentals. Support costs also increased from 2006 to 2007 as new safety equipment such as fire retardant clothing was purchased for employees. Other increases included small tool purchases, which had been budgeted in Fleet and Equipment Services in 2006. Details of THESL's Tool Cost Model are provided in Exhibit D1, Tab 9, Schedule 1 of this Application.

The cost increases from 2007 to 2008 reflect the addition of new design staff. Due to the large capital program being undertaken and the expected attrition of experienced staff THESL recognizes the need to hire more Design Technicians by 2008. The new design staff will be working alongside the experienced staff in the test years. This will ensure that when the expected attrition in Design Technicians occurs after 2010, THESL will be able to deliver on its capital plan.

The costs in Table 1 represent the Administrative support for all Capital and Operating programs. Exhibit D1, Tab 8, Schedules 1 to 3 and 6 shows Distribution Capital (Sustaining Capital, Reactive Work, Customer Connections and Engineering Capital) rising sharply year-over-year. Total Operating Programs are detailed in Exhibit F1, Tab 1, Schedule 1. Over the three test years, Operations Administration costs will decline as a percentage of the total of Capital and Operating programs. Table 2 shows the Total Operations Administration costs as a percentage of the total program spending.

Table 2: Total Operations Administration Costs as Total Program Percentage (%)

Description	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Operations Administration	13.6	14.4	14.7	14.0	13.4

OPERATIONS SUPPORT

WORK MANAGEMENT

Work Management plays a key role in THESL's commitment to continuous improvement. This area works to improve efficiencies and reduce capital and operating costs through the centralization of work management and reporting functions and continuous improvement in work processes throughout the organization. It seeks opportunities to improve efficiencies through standardized processes and procedures. To accomplish these goals it uses technology to automate tasks, provide a centralized view of the work to be performed and centralize performance measurement, reporting and decision-making functions.

DISCUSSION

This section describes the activities and initiatives associated with Work Management, Centralized Reporting and Decision-Making, and the Apprentice program.

ACTIVITIES AND INITIATIVES

The Work Management function focuses on the management of capital and operating programs through the efficient scheduling of work and resources, appropriate assignment of construction crews, standardization of design and estimating, and alignment of processes. It also works to ensure complete and consistent measurement and reporting of financial and operational Key Performance Indicators ("KPIs") as discussed below.

The group schedules all planned capital and customer connection work. The total gross system capital portfolio in 2006 was approximately $140 million. This figure will increase to $179 million in 2007 and is expected to increase to $219 million by 2010. This increase translates into a significantly greater amount of work and a larger number of resources requiring management and scheduling. The work management group

expects to keep its staffing levels constant despite the greater amount of capital spending anticipated in the test years. Work Management will continue to leverage current and emerging technology in order to manage increasing amounts of work without staff increases.

In the last quarter of 2006, a fully integrated scheduling tool in Ellipse, called Work Planner, was deployed to improve all aspects of project management from scheduling of the work, to resource management, (labour, material and vehicles), to job closing. The Work Planner tool gives a centralized view of the outstanding work and allows inter-departmental and cross-functional work force scheduling. Use of this technology will improve productivity for field staff and designers through improved resource utilization. The scheduling tool will allow visibility of resource availability and allow for scheduling adjustments to ensure resources are optimally utilized.

The scheduling tool is also used for customer work as described in Exhibit D1, Tab 8, Schedule 3. In recent years, THESL has had gross capital expenditures of approximately $35 million per year on customer connections and service upgrades. This translates to approximately 10,000 connections or upgrades each year. The improvement in scheduling and resource utilization will allow THESL to better meet its customers' schedules. This will result in improved customer satisfaction and an improvement in THESL's ability to deploy resources where and when they are required.

This initiative will also improve THESL's relationship with its suppliers. The scheduling tool will provide the Procurement Department with greater ability to predict longer-term material requirements and the dates on which these materials will be needed. Procurement can better work with suppliers to ensure material availability and reduce warehousing costs. The ability to improve material availability will also save on capital costs, as there will be fewer job delays due to insufficient materials.

In summary, the new integrated scheduling tool will allow crews to produce complete and consistent work packages in a timely fashion, including full and accurate designs, permits, clearances and all required materials.

Another key area of responsibility for Work Management is the measurement and reporting of KPIs, both financial and operating, for all operating groups and Asset Management. These KPIs include financial measures and measures showing production, as discussed below. The measures provide decision-makers with a view of program expenditures and progress on construction projects at a given point in time. Measurements are reported monthly for short interval control. Other key indicators include safety and customer outage durations and causes.

Work Management provides centralized measurement and reporting on performance to ensure consistency of data throughout the organization. It explains gaps in performance and recommends appropriate actions to improve performance. Opportunities are sought for improvement in work processes and in reporting. In addition, Work Management makes recommendations to implement these improvements. A centralized and consistent reporting mechanism provides more accurate and timely data to decision-makers to allow for more informed decisions.

The Workforce Staffing Plan in Exhibit C2, Tab 1, Schedule 6 details the need to hire and train Trades and Technical apprentices during the test years to replace existing workers who are expected to retire. The operating costs associated with the Trades apprentices are captured in Work Management, which is home to the Trades School.

WORK MANAGEMENT COSTS

Table 1 details the cost of providing Work Management services to THESL's operating groups.

Table 1: Costs of Work Management ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Costs	2.6	5.9	10.2	12.9	12.4

The primary cost driver is the Trades School. As per the Tables shown in Exhibit C2 Tab 1, Schedule 6, the headcount in this area is expected to increase from 38 in 2006 to 129 by 2010. The salaries, training costs and administration costs of this group are captured in Work Management.

The remaining costs are the labour and support costs (e.g., communication and office supplies) for the Work Management and Reporting Functions. The work management and continuous improvement functions were combined into Work Management as the result of a corporate-wide restructuring, which took effect in January 2007. In order to better support THESL's expanding capital and maintenance programs, and to ensure some arms-length performance measuring for governance purposes, it was necessary to bring internal staff with the appropriate skills from other areas of the corporation into Work Management. Cost increases from 2006 to 2007 reflect the costs of these additional staff for the combined function. Funding requirements increase from 2007 to 2008 due to the hiring of management staff and the use of external consultants. External consultants will be used for short durations to assist with automation improvements or other projects. Costs in the test years are expected to remain stable, increasing primarily due to payroll increases for existing staff; nevertheless, it is expected that the work program to be managed will grow during this period.

Maintaining existing staff levels will require greater efficiencies and the leveraging of technology to help manage the expanding work program, meet increasing measurement and reporting requirements, and incorporate continuous improvement opportunities as they arise.

CUSTOMER SERVICES

INTRODUCTION AND SUMMARY OF O&M COSTS

The Customer Services work program represents the work activities that are required to provide services to customers connected to THESL's distribution system and to meet the service levels stipulated in the OEB's 2006 Electricity Distribution Rate Handbook, issued May 11, 2005. These activities serve customers receiving electricity under the Regulated Price Plan, spot prices and retailer contracts.

THESL serves approximately 678,000 customers connected to its Distribution System, in the following rate classifications: Residential; General Service 0-50kW; General Service 50-1000 kW; General Service 1000-5000kW; and Large Users >5000kW.

Customer Services comprises two main operating areas: Meter-to-Cash and Customer Relationships. Meter-to-Cash ensures that meters are safely and correctly installed, accurately read for billing and that accounts are billed and collected in a timely manner. This group also manages the day-to-day issues with retailers including dealing with all information related to the daily transfers and billing transactions through the HUB.

The Customer Relationships team includes the call centre, a customer concern escalation group and the Key Accounts team. This team interacts with THESL's large volume customers to ensure their inquiries, requests for service and account issues are handled in an efficient and consistent manner. This group also manages the high level relationships with retailers including agreement maintenance and dealing with complaints that cannot be solved at lower levels.

In addition to these main operating areas, Customer Services staff is engaged in a number of system development projects and activities. Those related to system fixes and other

smaller improvements are included in the operating budget. However, the larger initiatives and those related to ensuring regulatory compliance are explained fully with their associated costs in Exhibit D1, in the capital spending narratives.

Smart Meter Program

THESL's Smart Meter Program is explained in Exhibit D1, Tab 8, Schedule 5 because most of the costs associated with this program are capital costs. Nevertheless, the Smart Meter Program will impact on Customer Services' O&M spending as follows:

- The costs associated with data collection and storage of smart meter metering data and the IESO costs for handing this information
- Cost to update and maintain the Time-of-Use Web Data presentation and Interactive Voice Response presentment to provide an automated option to retrieve Time-of-Use data for those customers who do not have internet access
- Time-of-Use rates implementation and roll out to customers will impact the call centre and billing area

Metering Services

Meter Services costs are expected to increase due to the installation of individual metering in all condominium buildings by 2010. This is expected to impact all areas of customer service including the call centre, postage costs, billing issues, meter installation and collections.

New Customer Information System

THESL is currently engaged in a three-year collaborative effort with Enersource Hydro Mississauga ("EHM") to design and build a customer information system that will meet the needs of both EHM and THESL and reduce costs in the future with respect to the programming of new regulatory requirements. The system, forecasted to go live in 2009

will provide improved functionality and efficiencies that should help in maintaining operating costs. This initiative is discussed in detail at Exhibit D1, Tab 10, Schedule 2-4.

Mobile Workforce Project

The first step in the Mobile Workforce Project is to prepare an RFP to identify a software product that will meet THESL's requirements for the electronic dispatching and managing work for field services, emergency response and construction crews. Following selection of a software product, Customer Services will work with the vendor to develop software to meet THESL's requirements. Once the software is completed it will be rolled out for implementation by THESL's workforce. This initiative is discussed in detail at Exhibit D1, Tab 10, Schedule 2-7.

Develop and Implement a New Customer Relationship Strategy

The intention of this project is to allow for the adoption of a more pro-active approach to dealing with customers. The project will identify how customers would like THESL to communicate with them, determine what information customers need and how they would like to receive or obtain it. It will involve customizing THESL's web site to provide a more personal information portal for customers. It will also utilize new ways to communicate with customers through emails, phone calls and text messaging to their cell phone. This initiative is discussed in detail at Exhibit D1, Tab 10, Schedule 2-5.

Develop and Implement a Flat Rate Water Heater Conversion Program

This program is designed to convert approximately 38,000 electric water heaters from flat rate to metered accounts. This is will encourage conservation by ensuring that customers are paying for the actual energy used to heat their hot water, rather than an estimate based on average usage.

COSTS

Table 1: Customer Services Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Metering Services	3.32	4.28	5.66	6.98	9.34
Smart Meter Opex	0.00	0.20	2.49	2.92	2.22
Billing/Remittance	9.90	10.13	10.60	10.39	10.19
Collections	10.23	9.87	10.06	10.61	10.68
Customer Relationship Mgmt.	9.10	10.55	13.40	13.72	14.05
Field Services	4.93	6.20	7.83	8.77	10.09
Administration	2.09	0.56	0.81	1.13	1.48
Business Support	0.94	1.08	0.95	1.00	1.01
Outage Management	0.46	0.10	0.10	0.10	0.10
Total Customer Services*	41.09	42.97	51.91	55.63	59.19

*Rows may not total due to rounding

The details of the year-over-year variances are presented in the schedules that follow covering specific Customer Services activities (Exhibit F1, Tab 7, Schedules 2-6). Below is a high level summary of the major factors driving increased costs from 2006 through 2010. The major driving forces for the increase in costs are smart meter installations and the anticipated move to Time-of-Use billing in 2008.

The Customer Services budget increased by $1.9M from 2006 to 2007:

- A net increase in THESL's contracted internal labour costs of $0.25M. This impact of the contracted increase on the O&M budget has been mitigated by the move of all staff involved in the smart meter project to the capital budget
- Call Centre costs increased by $0.70M due to anticipated higher costs at a new outsource call centre and the forecasted need for additional resources to meet service level targets

- The costs to communicate with meters will increase by about $0.10M as the collector units associated with smart meters are commissioned
- Allocated charges for occupancy increased by $0.90M based on the cost of the company-wide Facilities plan

Costs are forecast to increase by $9.0M from 2007 to 2008:

- A large portion of this is due to a $1.60M contracted increase for labour costs
- $.30M is for three additional staff to assist with the work associated with smart meter installations and Time-of-Use billing rollout
- A $2.20M increase in outsource call centre costs is forecast for the expected impacts of Time-of-Use billing
- $0.40M is projected for corporate communication costs associated with Time-of-Use billing
- $0.30M is for increased costs in billing and collections relating to Time-of-Use rates and an increase in customers as a result of condominiums being outfitted with individual smart meters
- $2M is for the conversion of Flat Rate Water heaters.
- $0.50M in new costs are necessary for remote communications with data collection points for smart meters

The increase from 2008 to 2009 is $3.70M. This includes:

- $1.30M is for anticipated labour cost increases
- $.30M is for three additional staff to assist with the additional work associated with the smart meter rollout and the Time-of-Use billing implementation
- $0.90M in new costs are necessary for remote communications with the additional data collection points for smart meters
- An increase of $0.40M is projected for corporate communication costs associated with Time-of-Use billing

- A $0.50M increase in the Bad Debt expense is expected due to higher bills related to Time-of-Use billing
- $0.20M is for postage and increased billing costs
- $0.10 M is for increased collection costs

The increase from 2009 to 2010 is $3.50M. This includes:

- $1M for anticipated labour cost increases
- $0.40M for an additional four staff to assist with the added work associated with the installation of smart meters and the Time-of-Use billing rollout
- $0.15M for increased billing cost relating to payment processing and postage associated with anticipated increases and additional customers due to the condominium conversions to individual meters
- $0.70M in new costs are necessary for remote communications with the final installed data collection points for smart meters
- The balance of $1.2 is an increase in overall operating costs as smart meter work transitions from installations (capital) to maintaining and replacing the installed smart meters (O&M)

CUSTOMER SERVICES

METER SERVICES

Introduction

Meter Services maintains, repairs and replaces THESL's revenue meters and wholesale metering installations. The revenue meters allow THESL to accurately bill customers for their consumption. The wholesale metering installations ensure that THESL properly records the energy use on its system that forms the basis of invoices from the IESO.

Activities

Meter Services operates a meter shop that is certified under the *Electricity and Gas Inspection Act* to be a Measurement Canada accredited meter verifier. The key functions of the shop are:

- To perform the sample testing on in-service meters as required by Measurement Canada;
- To undertake calibration and cleaning of removed meters before they are reused; and
- To assess the accuracy of meters removed as a result of customer issues.

The meter shop annually tests 10,000 meters for routine re-verification, and examines 3,200 meter changes for compliance testing. A compliance sample group of 10,000 to 15,000 meters is formed from a homogeneous lot (same meter type, electrical characteristics, manufacturer and seal year). Each year between 28 and 220 of the meters in each compliance sample group are randomly selected to be tested for accuracy. Of the 65 sample groups tested annually, typically one or two groups fail, resulting in the need to replace all the meters in that sample group.

In addition to meter testing, Meter Services is responsible for the maintenance of the approximately 678,000 revenue meters owned by THESL. THESL conducts inspection and calibration of all revenue metering. Sample groups for residential meters are required to be reviewed every 12 years. General Service watt-hour only meters are reviewed every eight years, and General Service meters with demand registers, every six years. In 2006, 630 meter installation checks were completed on commercial new services or service changes. Meter Services also performs approximately 9,000 residential, 600 commercial and 100 interval meter changes annually due to defective meters. All defective residential meters are now being replaced with smart meters.

Meter Services is also responsible for the 108 wholesale meters used to measure load at grid supply points. Most of these wholesale meters currently are owned by Hydro One. However, as the seal periods on these meters expire, THESL is assuming responsibility and ownership of these meters. THESL is bound by IESO Market Rules to ensure that these meters remain compliant with IESO requirements. This work is funded from the capital budget and is described in Exhibit D1, Tab 8, Schedule 4.

Finally, Meter Services retrieves hourly consumption data from approximately 2,500 remotely interrogated meters located at larger customers' sites. THESL staff also completes the data entry and updates records associated with meter changes to ensure all meter records in the customer information system are accurate for billing purposes.

The cost of approximately 2,200 telephone lines required to interrogate the meters of THESL's larger customers historically has been recovered through the application of a separate charge on these customers' bills. As THESL moves forward with the installation of smart meters, by 2010 the number of meters requiring remote interrogation will increase to 30,000. These include the residential collector devices and many small- to mid-General Service meters. It is not possible to bill the communication costs for a

collector to one customer as each collector collects information for 300-400 meters. In addition, where collectors cannot be used for small- to medium-sized General Service customers, direct billing of communication costs would impose a substantial additional cost on these customers for the meter reading that is currently included in their distribution rates. Based on these facts, THESL has decided that the communication costs for all meters should be included in rates rather than recovered through a separate charge. As the current cost of phone lines is significant and could rise to $9M by the end of 2010, THESL will be investigating other lower cost communication options and has included lower costs for this function in the associated budgets for the test years.

Beginning as early as the third quarter 2007, THESL will also begin installing individual metering in condominiums. While the initial costs associated with this work will be included in the capital Metering budget, costs have been included in 2008 and beyond for ongoing maintenance work.

Table 1: Meter Services Operating Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Metering Services	3.32	4.28	5.66	6.98	9.34

The increase in the metering budget from 2006 to 2007 is $0.97M. Approximately $0.50M of this is due to the increased communication costs for smart meters as THESL continues to utilize telephone lines for this purpose in 2007 and $0.47M represents an increase in allocated occupancy costs related to the Facilities Plan.

From 2007 to 2008 the budget increase is $1.10M. Of this total, $0.50M is attributable to the additional cost for smart meter communications while $0.30M is for ongoing maintenance of the meters installed in condominiums. A contracted increase in THESL's

internal labour costs accounts of $0.12M and $0.14M represents an increase in the allocated occupancy costs related to the Facilities Plan.

From 2008 to 2009 the budget increase is $1.20M. About $0.90M is related to further increases in smart meter communication costs, $0.10M is for ongoing maintenance of the meters installed in condominiums and $0.20M covers an anticipated increase in labour costs.

From 2009 to 2010 the budget increase is $2.10M. The major increase in 2010 ($1M) is due to a transition from capital work relating to the smart meter installations to maintenance and repair work on the installed smart meter. This produces the increase in operating costs shown here and a decrease in capital spending for smart meters of $13M shown in Exhibit D1, Tab 8, Schedule 5. The remaining increases are $0.70M for a further increase in smart meter communication costs, $0.10M for ongoing maintenance of the meters installed in condominiums and $0.20M for an anticipated increase in labour costs.

CUSTOMER SERVICES

BILLING AND REMITTANCE

Introduction

Billing and Remittance is responsible for reading meters, preparing customer bills based on the meter data, and billing for other services provided to customers. Billing and Remittance also processes all customer payments through various channels, ensuring payments balance to the General Ledger. Currently, most residential and small General Service (<50kW) customers are billed bi-monthly. Other General Service customers and larger customers with remotely interrogated meters ("RIMS") receive monthly bills. THESL complies with all applicable billing requirements in the Distribution System Code including the provision of a validating, estimating and editing ("VEE") process.

Activities

The role of this department is to ensure that accurate meter readings are captured, so as to deliver valid regular and final bills to THESL's customers and ensure that payments are timely and accurately applied.

This group also manages the day-to-day relationships with retailers. This includes addressing ongoing issues, information transfers and billing transactions and paying the cost of the daily transactions through the HUB.

In addition, this area includes a team that is responsible for the preparation of invoices and collections for THESL's miscellaneous accounts receivable process. This includes invoices for customer-driven projects and claims for damage done to THESL assets.

The introduction of Smart Meters will impact the operation of Billing and Remittance. Accordingly, departmental processes are being reviewed and adjusted in anticipation of

the challenges that will result from the installation of smart meters. In the fourth quarter of 2007, THESL will begin to phase-in the process of remotely obtaining accumulative readings to bill those customers whose smart meters have been installed and updated into the customer system. This move to an automated process will reduce the incidence of error, and by extension, work required to correct errors. In the event of a dispute, a reading can be quickly checked on-line to validate a bill.

The technology and processes required to read smart meters on an hourly basis, store and verify the data, submit data to the IESO for validation, produce the Time-of-Use bills and display the detailed information to THESL's customers in a timely manner, is adding considerable complexity to the meter reading and billing process.

As the practice of remote meter reading grows, the costs associated with manual reads will continue to decline until the end of 2010. Manual meter reading costs will drop from $3.5M in 2006 to $1M in 2010. The IESO has confirmed that THESL will be required to pay a fee to the IESO for the checking and transfer of smart meter readings at some point in the future when the IESO's processes go live. As the IESO has not provided any indication of what these actual costs will be, THESL feels it is prudent to budget for these anticipated costs, and has included $1M for each of the years 2008, 2009 and 2010. This is an estimate only and combined with the meter reading costs of $1M it is a stretch goal in an effort to keep costs stable.

THESL currently has approximately 678,000 meters, about 600,000 of which are read bi-monthly and 75,000 on a monthly basis. THESL issues 4.9 million bills per year. In addition, there are approximately 2,500 remotely interrogated meters for large use customers that are read and billed on a monthly basis using the spot energy price or retailer rates.

THESL also has approximately 53,000 flat rate services. These flat rate services include Streetlighting, telephone booths, bus shelters, cable television boosters and signs. Also included in this number are approximately 38,000 water heaters that are billed on a flat rate basis.

In addition, Billing and Remittance processes approximately 50,000 billing adjustment requests per year received from the call centre, 120,000 customer moves per year; and maintains information on 120,000 customers who pay their bills using a pre-authorized payment plan and 24,000 customers who receive their bills on line using e-billing options.

Finally, the department ensures that internal controls are in place for existing processes, developed for new processes and reviewed regularly to ensure compliance.

Table 1: Billing/Remittance Operating Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Billing/Remittance	9.90	10.13	10.60	10.39	10.19

The operating costs for Billing and Remittance increased by $0.23M from 2006 to 2007. The main driver of this change was an increase in postage costs of $0.20M to cover planned increases as advised by Canada Post. Resource costs increased by $0.50M due to contracted labour agreements and an increase in staff due to an internal reorganization. Meter reading costs were reduced by $0.50M because of plans to read a number of smart meters remotely by the second quarter of 2007.

The increase from 2007 to 2008 is $0.46M. This is due to a contracted increase in labour costs of $0.10M. The budgets for bill mailing and return envelopes increased by $0.11M, payment processing by $0.10M and postage costs by $0.15M. This is to cover

the expected increase in the customer base associated with new accounts as condominiums are converted from bulk to individual metering.

Costs are forecast to decrease by $0.20M from 2008 to 2009. While labour costs and postage are expected to rise slightly, meter reading costs are expected to drop by $0.50M as the benefit of remote reading of smart meters is realized.

Costs are expected to drop another $0.20M from 2009 to 2010. Again while labour costs and postage are anticipated to increase, meter reading costs are planned to be reduced by an additional $0.50M.

CUSTOMER SERVICES

COLLECTIONS

Introduction

Collections is responsible for ensuring appropriate follow-up and collection of unpaid accounts pursuant to THESL's guidelines for managing overdue accounts. These guidelines meet all the requirement of the Distribution System Code and other OEB codes that impact collections and have been approved by THESL's senior management. They have also been reviewed and approved through THESL's Internal Control Processes. THESL's follow-up and collection activities are appropriate and help to maximize customer payments and reduce uncollectables, thereby helping to reduce upward pressure on rates.

Activities

To accomplish its follow-up and collection activities, the department:

- Mails out over 300,000 reminder notices annually;
- Places 150,000 automated payment reminder phone calls to customers annually;
- Issues almost 100,000 field collection service orders annually to THESL's field collection contractor and some internal field staff;
- Disconnects 8,000 accounts per year for non-payment using THESL's field collections contractor;
- Tracks Days Sales Outstanding ("DSO"), which measures the average number of days that it takes to collect revenue, and reports on how this figure compares to plan. (To establish this plan, the month-end accounts receivable balances are projected for the year based on history and assumptions, such as weather, rates and general economic indicators. Once this projection is established, the average daily billing is determined and the DSO target is the total accounts receivable divided by the average billing);

- Monitors about 100,000 accounts with deposits and oversees the annual process to refund deposits as required;
- Processes about 400 bankrupt accounts annually to ensure that they are closed, the appropriate claims are made, and the necessary follow-up is completed;
- Prepares and sends 7,000 inactive accounts to external collection agencies for follow up and collection; and
- Performs quarterly write-off activities.

As a result of these and other actions, the DSO averaged 21 days in 2006. With a due date that is no less than 16 days past the mailing date, this indicates that these collection activities were successful. In 2006 the contract field collectors delivered 100,000 notices to customers and collected approximately $3.2 million as a result of this activity. Of the $5M in accounts that THESL sent to external collection agencies for action, THESL has been able to recover approximately $1.4 million. The cost of this collection activity is 25 percent of the amount collected or approximately $.35M and is included in the collection expense budget.

In addition to its work on customer accounts, the department completes a monthly financial report, which includes a reconciliation of the allowance for doubtful accounts. Following an established procedure, at month-end the outstanding accounts receivable balances in various categories, bankrupt accounts and accounts considered to be “at risk” are reviewed to determine THESL’s estimated Bad Debt exposure. This estimated value is compared to the value determined from the previous month. These reports are reviewed with senior management. Variances are explained as part of the month-end financial process and adjusted quarterly when required. Trends are carefully monitored so that corrective action can be taken immediately when required.

Finally, the department works to ensure internal controls are in place for existing processes and developed for new processes. These controls have been designed to ensure that major processes like the collection of accounts and bad debt write-offs follow well-defined steps that are checked, audited and signed-off by management at various stages to ensure accuracy. All existing and new processes are reviewed annually to ensure that adequate controls are in place and the procedures in use are still valid.

Costs

Table 1: Collection Operating Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Collections	10.23	9.87	10.06	10.61	10.68

From 2006 to 2007 the budget decreased by $0.37M. Of this amount, $0.22M was a reduction in resource costs associated with a move of staff to the Billing department. The balance was a decrease of $0.15M in the budgeted Bad Debt expense for 2007.

The increase from 2007 to 2008 is $0.18M. This is made up of a $0.06M increase for contracted labour costs and a $0.1M anticipated increase in collection costs as time-of-use billing begins.

From 2008 to 2009 there is an increase of $0.56M. Of this amount, $0.5M is an increase in Bad Debt Expense to cover an anticipated increase in bad debt associated with time-of-use billing. This projection is based on higher billed amounts and anticipated confusion about time-of-use rates, which could lead to an increase in billing disputes and a change in payment patterns. The balance of $.06M is for anticipated labour cost increases.

From 2009 to 2010 the costs are projected to increase by $0.06M. This is to cover off anticipated labour cost increases.

CUSTOMER SERVICES

CUSTOMER RELATIONSHIP MANAGEMENT

Customer Relationship Management ("CRM") provides services to approximately 678,000 customers supported by THESL's Call Center, Escalations Group, and Key Accounts Team. The Call Centre handles an average of 41,000 written requests, including e-mails and 850,000 customer telephone inquiries per year. The Escalations Group successfully handles high level customer complaints including those received from the OEB, THESL's senior executives and local and provincial political representatives. The Key Accounts team ensures all concerns of THESL's high usage customers are given immediate attention.

Customer inquiries are handled by phone, email and in writing. Annually, THESL responds to over 37,000 written requests and 4,000 e-mails from customers requiring follow-up within time frames established by the OEB's service quality measures. Dedicated staff, process streamlining, and the use of technology has allowed THESL to achieve a consistent performance level of meeting or exceeding the OEB Service Quality target of responding to 90 percent of all written inquiries within 10 days, in each year since Market Opening in 2002.

In addition to written inquiries, the call centre receives an average of 850,000 phone inquiries annually and has exceeded the OEB service quality target of responding to 65 percent of calls within 30 seconds consistently since 2002. The Call Centre average service level from 2002 through 2006 is 78 percent of all calls answered in 30 seconds.

Along with process improvements and technology, cost escalation has been mitigated by utilizing an outsource Call Centre to assist in the handling of the daily call volumes. This enables THESL to maintain the required number of staff to ensure service levels are

achieved. We are also able to react to forecasted demands of higher or lower call volumes when necessary within a reasonable time frame. It is most efficient and cost effective to add or reduce staff at the outsource call centre as call volumes dictate.

After five years with the same outsource call center vendor, an RFP process was initiated in late 2006 in an effort to achieve lower cost and improve service. A new vendor has been selected and the switch to this vendor occurred in May 2007. Although higher costs had been budgeted, costs are actually expected to decrease. The lower costs resulting from this change will allow THESL to manage expected higher future call volumes associated with conservation and demand management projects in a more cost effective way.

Customer inquiries to the call center cover a broad spectrum and involve most aspects of THESL's business including:

- Ensuring customer records are updated as required to track customer moves and for other changes in customer information;
- Verifying information and explanations relating to billing, collections and meter accuracy;
- Requesting meter checks;
- Responding to inquiries relating to Conservation and Demand Management ("CDM") Programs including Summer Savings , Peak Saver, Refrigerator Bounty and other programs sponsored by THESL and/or the Ontario Power Authority ("OPA");
- Providing first contact for power outage calls. Using the Outage Management System, Customer Service Representatives enter the information for follow up by the Customer Service Dispatch team. The Customer Service Dispatchers review the calls and determine whether the outage is an isolated incident or part of a larger outage. They dispatch field service representatives to single outages, part

power calls and wires down. Larger outage information is passed to the Trouble Dispatch team in System Operations for follow-up.

The Escalations Group handles approximately 1,000 customer issues annually that are escalated through the call centre during daily operations. Another 150 are received through THESL's Senior Executives and City Councilors and approximately 40 are received directly from the OEB. These issues cover a wide range of customer concerns. The two issues raised most frequently relate to power outages and high bills.

The Key Accounts Team responds to issues raised by large volume customers and assists with their energy management issues. The Team meets with customers as required, to resolve billing issues, to coordinate planned outages and explore possible CDM projects.

Relationships with retailers operating within THESL's territory are also managed by the Customer Relationship Management team. The manager and a coordinator oversee ongoing communications with retailers and ensure that new retailers complete the necessary paper work prior to set up. Ongoing customer issues and complaints related to retailer activities in THESL's service area are communicated to the retailers as appropriate.

Throughout 2007 and 2008, the Customer Relationship Management team will be developing a strategy to improve customer service by being more proactive in its communication methods. This will include improving the customer information available on THESL's WEB site; expanding the Interactive Voice Response ("IVR") to provide easier access to information on current programs; contacting customer groups that will be impacted by changes before they occur; and conducting regular surveys to measure the effectiveness of these changes. Once developed, this strategy will be initiated through process changes and the use of new technologies. The most significant

benefit that can be achieved through this initiative is to get information to customers in a timely manner in order to avoid the costs associated with increased call volumes.

Costs

Table 1: Customer Relationship Management Operating Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Customer Relationship Mgmt	9.10	10.55	13.40	13.72	14.05

The increase in costs from 2006 to 2007 is $1.40M. Of this amount, $0.70M is due to an increase in the outsource call centre budget to cover an expected increase in costs with a move to a new vendor (actual costs are expected to be lower due to the negotiation of a price lower than the budgeted amount), $0.20M represents an increase in allocated costs for occupancy and IT and $0.40M is due to a contracted increase in labour costs and the move of three staff into this area as a result of a department reorganization.

From 2007 to 2008 the budget increase is $2.80M. Of this amount $2.20M is an increase in the outsource call centre budget to cover the hiring of approximately an additional 35 staff to accommodate the higher call volumes expected when Time-of-Use billing is initiated. This is to ensure that the required service levels are maintained. The balance is $0.330M for a contracted increase in labour costs and a loss of $0.15M of labour-related recoveries previously received from affiliates for Streetlighting and Rental Water Heater work. The removal of this work has allowed for the reallocation of a small number of resources to improve CRM service levels.

The budget increase from 2008 to 2009 is $0.3M. This is due to anticipated increases in labour costs.

The change from 2009 to 2010 is also $0.3M. This too, is due to anticipated increases in labour costs.

CUSTOMER SERVICES

FIELD SERVICES

Introduction

The Field Services group completes the field work associated with Customer Service functions. This group is also responsible for completing underground locate requests.

Activities

The Field Services group performs the following activities:

- Install residential single phase smart meters in support of the smart meter project. Seventy percent of the staff are dedicated to this project;
- Complete approximately 11,500 customer service requests annually for meter reading checks, bill investigations to check that a meter is operating correctly, and higher voltage services disconnects and reconnects that for safety reasons cannot currently be completed by an outsource vendor;
- Assist with over 4,000 calls during storms involving situation where wires are down, to verify that the downed lines are electric service wires and to make the situation safe where possible or stand by to keep the area safe until the line crews arrive to complete repairs; and
- Investigate and resolve over 2,100 flat rate water heater problems.

THESL is moving to convert flat rate water heaters to metered services. Field Services is developing the strategy and plan to accomplish the conversion of 38,000 flat rate water heaters to metered service over seven years beginning in 2008. Field Services is also responsible for underground cable locates. Field Services locates and marks THESL underground distribution plant for customers and contractors prior to the beginning of excavation. This service is provided in accordance with Electrical Safety Authority guidelines for *Excavating in the Vicinity of Distribution Lines*. This service is provided

at no charge to encourage customers and contractors to request locates and thereby avoid hazardous situations or injury and potential service interruptions.

The volume of cable locates is driven by external demand. In each of 2005 and 2006, Field Services responded to approximately 60,000 requests. In 2007, this number is expected to increase slightly because of the many ageing infrastructure projects that will be initiated throughout Toronto. It is then expected that the number will level off in 2008 and beyond.

THESL uses internal staff and external contractors to perform cable locates. This allows THESL to respond to the fluctuating volume of requests and control costs. In 2006, 60 percent of work was contracted out. This percentage is likely to increase as attrition reduces the available internal labour pool and internal staff is directed to other assignments. Performance is tracked by the OEB's "Underground Cable Locates" service quality indicator of 90 percent of requests completed within five business days. From 2001 to 2006 THESL achieved an average service level of 94.5 percent.

Costs

Table 1: Field Services Cost ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Field Services	4.93	6.20	7.83	8.77	10.09

The budgeted increase in the Field Services costs from 2006 to 2007 is about $1.2M. This increase results from reduced labour-related recoveries of $1.7M due to the sale in February 2007 of the Rental Water Heater business, by TH Energy, THESL's affiliate. As a result of this divestiture, the majority of the field staff was reassigned in the second quarter of 2007 to installing smart meters. Clerical staff was reassigned to smart meter

back office update processes or to work in other parts of the organization. As part of a planned restructuring, labour costs were reduced by $.5M as the result of the movement of four forestry resources to another department.

The cost change from 2007 to 2008 is an increase of $1.70M. Two million dollars has been budgeted for the process of converting flat rate metered water heaters to metered services. This program will include a communication program with customers and incentives to convert. There is an offsetting reduction in costs for the external cable locate vendor of $.55M as a result of a move to a new vendor and negotiated cost reductions with existing vendors. An additional $0.25M for labour-related recoveries was lost due to the sale in February 2007 of the Rental Water Heater business by TH Energy, THESL's affiliate.

The projected cost increase from 2008 to 2009 is $0.91M. This is due to anticipated increases in labour costs of $.2M and another $.7M for the process of converting flat rate metered water heaters to metered services.

From 2009 to 2010 costs are forecast to increase by $1.3M. The increase in 2010 is due to a transition from capital work relating to the smart meter installations to maintenance and repair work on the installed smart meters. Many of the field staff will be redeployed to maintenance work on smart meters and this work becomes part of the operating budget. Capital costs will be reduced as smart meter installation ends. See Exhibit D1, Tab 8, Schedule 5, for information on the Smart Meter Capital Budget.

SUMMARY OF THESL ADMINISTRATIVE AND GENERAL ("A&G") EXPENDITURES

The proposed A&G expenditures represent costs of the centralized activities necessary to THESL's operations. These include:

- Finance
- Treasury, Rates and Regulatory
- Legal
- Communications
- Information Technology
- Environmental Health and Safety
- Organizational Effectiveness

The proposed A&G expenditures also include certain corporate costs for governance and charitable contributions. THESL makes no political contributions and does not engage in research and development activities outside of the normal course of business.

The proposed A&G expenditures were developed from a comprehensive business planning process. THESL submits that its focus on business planning ensures that costs are appropriately managed and cost effective work practices are established and revised as necessary. This process is described in detail at Exhibit. C1, Tab 4, Schedules 1 and 2.

A&G expenses were treated as shared services from THESL's perspective in the 2006 Rate Application. In order to provide greater clarity regarding the distribution expenses associated with THESL's business, THC was re-organized to bring the shared services organizational units and expenses into THESL, effective January 1, 2007.

The overall distribution expenses associated with these business units for the historical, bridge and test years are shown in Table 1 below:

Table 1: Distribution Expenses Administrative and General ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Governance	48.33	10.55	12.05	11.27	9.92
Charitable Contributions	0.21	0.05	0.05	0.05	0.05
Political Contributions	0	0	0	0	0
Research and Development	0	0	0	0	0
Finance	3.10	3.42	4.51	4.65	4.74
Treasury, Rates and Regulatory	9.56	10.38	14.05	13.77	14.55
Legal	2.49	2.64	2.66	2.75	2.84
Communications	3.80	3.61	3.88	4.00	4.12
Information Technology	22.65	26.56	28.56	29.59	29.57
Environmental Health and Safety	2.95	2.74	3.22	3.34	3.47
Organizational Effectiveness	3.31	4.48	5.69	5.98	6.08
Total	**96.40**	**64.43**	**74.67**	**75.40**	**75.34**

A more detailed description of these business activities and an explanation of year-over-year variances are provided in Tabs 2 to 12 of this Exhibit.

The Shared Services Study, filed at Exhibit Q1, Tab 1, Schedule 1 sets out the total costs for these business units including costs attributed to all affiliates. It fully explains the process by which costs have been allocated between THESL and the affiliates.

GOVERNANCE

INTRODUCTION

The Governance Responsibility Center includes costs related to the office of the President of Toronto Hydro-Electric System Limited ("THESL") and related stewardship and governance activities. The primary responsibilities of the President include developing and monitoring of THESL's strategic direction, executing the Board of Directors' directives and policies, and providing overall direction to THESL's operations. In addition to direct costs related to the President and governance activities, this department includes general costs that relate to the entire THESL organization such as Shared Services allocation, general consulting expenditures, and capital taxes.

ADMINISTRATIVE AND GENERAL EXPENSES

The following table presents the total administrative and general ("A&G") expenses of the Governance Responsibility Center.

Table 1: Total Administrative A&G ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Total Costs	48.3	10.55	12.05	11.27	9.92

VARIANCE ANALYSIS

2006 Actual versus 2007 Bridge

Administrative and general expenses in 2006 were $48.3 million compared to $10.55 million in the bridge year representing a decrease of $37.75 million. The decrease is primarily due to lower allocated costs from Toronto Hydro Corporation ($42.20M) resulting from a re-organization between Toronto Hydro Corporation ("THC") and THESL which was effective on January 1, 2007, higher labour recovery related to 2007 CDM activities, which was recorded in the Governance Responsibility Center ($2.70

million), and an adjustment of THESL post employment benefit expense to reflect the latest (2006) actuarial review ($1.0 million). These decreases were partially offset by the fact that the 2006 figure included a one-time property tax refund ($4.80 million) and a one-time deferral of pension contribution to a regulatory asset in 2006 reflecting the cash pension costs after the OMERS contribution holiday ended on December 2002 ($1.7 million). The decreases were also offset by 2007 increases in capital tax expense ($0.3 million), adjustment for vehicle utilization ($0.5 million) and additional consulting fees for commodity tax recovery ($0.4 million).

2007 Bridge versus 2008 Test

Administrative and general expenses in 2007 are $10.55 million compared to $12.05 million in 2008, representing an increase of $1.5 million. The increase primarily relates to labour recovery related to the conservation and demand management activities. In the bridge year, labour recovery related to the conservation and demand management initiative is recorded to the Governance Responsibility Center whereas in the test years this amount is recorded to the responsibility centres conducting the work.

2008 Test versus 2009 Test

Administrative and general expenses in 2008 are $12.05 million compared to $11.27 million in 2009, representing a decrease of $0.78 million. The decrease primarily relates to lower capital tax expense.

2009 Test versus 2010 Test

Administrative and general expenses in 2009 are $11.27 million compared to $9.92 million in 2010, representing a decrease of $1.35 million. The decrease primarily relates to lower capital tax expense.

CHARITABLE CONTRIBUTIONS

THESL has included charitable donations in its 2006-2010 distribution revenue requirement request. THESL makes charitable donations to a number of community based organizations. The primary beneficiaries are the United Way and programs that support low-income customers in paying their electricity bills; urban forest protection and local environmental organizations; energy conservation organizations; public school programs related to science and conservation and employee volunteer grant programs.

Table 1: Charitable Donations ($000s)

Charitable Donations	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Total Cost	208	50	50	50	50

THESL expects to maintain the same level of charitable contributions in the bridge and test years.

POLITICAL CONTRIBUTIONS

THESL is a municipal electric distribution company, the governance and corporate structure of which is such that THESL does not make political contributions.

RESEARCH AND DEVELOPMENT EXPENDITURES

The revenue requirement included in this application does not include expenditures relating to research and development ("R&D"). While THESL has claimed and will continue to claim R&D tax credits, the expenditures giving rise to these credits are incurred in the ordinary course of business and do not constitute distinct R&D expenditures.

FINANCE DEPARTMENT

INTRODUCTION AND SUMMARY OF A&G COSTS

In 2007, the Finance function was reorganized to reflect the direct causality of certain costs. Accordingly employees spending the majority of their time on THESL were transferred from the THC Shared Services Finance function to the newly created THESL Finance function. Other finance functions such as Taxes and Internal Controls were kept in the THC Shared Services function for governance reasons and are included in the THC Shared Services allocation to THESL.

The Finance department at Toronto Hydro-Electric System Limited ("THESL") is comprised of the following four groups – Controllership, Planning and Reporting, Accounts Payable and Payroll (collectively referred to as "Finance"). Finance works closely with the THESL operational units, other THESL business partners, as well as their counterparts at Toronto Hydro Corporation ("THC") to ensure that the THESL financial statements and reports are fairly and accurately presented and that THESL's management has the financial information it requires to effectively run the company.

The following table presents the total administrative and general ("A&G") costs of the THESL Finance department.

Table 1: THESL Finance A&G Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Controllership	-	0.45	0.71	0.73	0.75
Planning and Reporting	-	1.33	2.05	2.10	2.18
Accounts Payable	-	0.97	1.06	1.10	1.06
Payroll	-	0.67	0.69	0.72	0.75
Total	3.1	3.42	4.51	4.65	4.74

CONTROLLERSHIP

Responsibilities

The primary responsibilities of the Controller include setting the direction of the Finance department to meet strategic and organizational needs for finalizing reporting within a public company and business analyses. Accordingly, the Controller, manages the Planning and Reporting, Accounts Payable, and Payroll functions of THESL.

The following table presents the total A&G costs related to the Controller.

Table 2: Controllership A&G costs ($ Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Total	0.45	0.71	0.73	0.75

The increase in operating costs between the bridge year and the test years is primarily due to an expected increase in employee fitness allowance (gym membership) costs as higher employee participation is expected and increased payroll-related costs. The fitness allowance for all THESL employees is recorded in the Controller function.

PLANNING AND REPORTING

Responsibilities

The Planning and Reporting group was formed in 2007 after the reorganization was completed at the end of 2006 and includes personnel previously employed by THC and newly hired personnel. This group is expected to be fully staffed in 2008. The primary responsibilities of the Planning and Reporting group include the management and preparation of annual budgets, periodic forecasts, long-range projections, financial statements, and variance analyses. The team works closely with operational groups to ensure that financial transactions are appropriately recorded in financial systems and that financial risk is managed by implementing and supporting adherence to internal controls. The Planning and Reporting team also works closely with the Information Technology group to ensure that the financial planning and reporting systems are appropriately managed.

The following table presents the total A&G costs related to the Planning and Reporting group.

Table 3: Planning and Reporting A&G Costs ($ Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Total	1.33	2.05	2.10	2.18

The increase in costs between the bridge and test years reflects the additional payroll and hiring costs to complete staffing of the new group as well as an increase in expected external services costs to modify the planning and reporting system and related processes.

ACCOUNTS PAYABLE

Responsibilities

The primary responsibilities of the Accounts Payable function include the accurate and timely payment of supplier invoices, processing of employee reimbursement claims,

processing of THESL customer refunds and credit card expenditure reviews. Accounts Payable is also responsible for the implementation of related internal control activities and analyses.

The following table presents the total A&G costs related to the Accounts Payable function.

Table 4: Accounts Payable A&G Costs ($Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Total	0.97	1.06	1.10	1.06

The increase in costs between the bridge and test years is primarily due to general payroll increases and expected lower recovery from affiliates.

PAYROLL

Responsibilities

The primary responsibilities of the Payroll function include the accurate and timely processing and payment of employee payroll, government/institutional remittances, and Canada Revenue Agency T-slip preparation. The Payroll group works closely with Human Resources, Timekeepers, and operational representatives to ensure appropriate processes and internal controls have been designed and implemented.

The following table presents the total A&G costs related to the Payroll group.

Table 5: Payroll A&G Costs ($ Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Total	0.67	0.69	0.72	0.75

TREASURY, RATES AND REGULATORY AFFAIRS

INTRODUCTION & SUMMARY OF A&G COSTS

Treasury Department

The Treasury Department is responsible for Cash Management, Debt Management, Investor Relations, Risk Management and Insurance.

Cash Management includes traditional front office, mid-office, and back-office functions. The Front office handles the daily investing and borrowing of cash and ensures that adequate funds are available as needed. The Mid-office is responsible for risk control and for independently verifying front-office information. The Back office handles the daily reporting and reconciliation of THESL's cash position and is responsible for all interfaces to the general ledger and to the sub-ledger accounts.

Investor Relations oversees all regulatory filings with the Securities Commission, liaises with "street" analysts and credit rating analysts, and monitors the key financial ratios that are used to establish the Company's credit rating.

A formal Risk Management program is in place to assess current risk activities at an enterprise level and to ensure that controls are in place to eliminate or mitigate these risks. Certain risks can be reduced through a variety of loss prevention techniques, by contractually transferring the risks to another company, or by transferring risks to the insurance market. THESL's current insurance policies provide coverage for a variety of losses and expenses, including comprehensive general liability, all risk property and boiler and machinery insurance, liabilities of directors and officers and automobile liability.

Rates Department

The Rates Department is responsible for overseeing distribution rate development and implementation, for monitoring and reporting various power revenue and cost accounts, and for developing the annual forecasts of load and number of customers.

In addition to the calculation and application of OEB distribution rate orders, the department has been directly involved in OEB initiatives such as the Regulatory Assets Review (RP-2004-0100) and the Cost Allocation Review (EB-2005-0317). In the future, the OEB's rate design process (EB-2007-0031) will engage the department's rate analysts. With the implementation of the smart meters, and the increased focus on CDM activities, it is expected that the Rates Department will play a key role in the analysis and development of potential new rate structures, consistent with generally accepted rate-making principles. These new rate structures will benefit from the enhanced load information obtained from smart meters and help promote CDM activities.

Monitoring and reporting activities carried out by the department are inputs into both the monthly financial reporting and the daily and monthly reconciliation of IESO statements and invoices as well as liaison in the reporting and disbursement of various government-mandated rebates to customers and retailers, such as RPP and OPG rebates. THESL bills customers on a monthly or bi-monthly basis for power consumed. For financial reporting purposes, the company records earned revenue based on volumes sold in monthly periods. Department analysts are responsible for providing the monthly earned revenue and cost of power expenses for financial reporting. Reporting of various regulatory accounts (such as RSVA accounts, CDM accounts, and Smart Meter accounts, including carrying charges applying OEB-prescribed rates) is also the responsibility of the Rates Department.

THESL's revenue projections are based on load and customer forecasts. The department maintains and updates the load and customer forecast models and provides the forecast for the annual budgeting exercise. As the company's load data becomes richer, with an increased historical database and with additional data from smart meters, it is anticipated that the load models will continue to evolve.

Regulatory Affairs Department

The Regulatory Affairs Department is Toronto Hydro's contact and liaison with the OEB, the IESO and other agencies on all regulatory matters and is the main repository for regulatory records and documentation. In consultation with internal/external stakeholders, Regulatory Affairs develops THESL's positions on defined issues, prepares regulatory filings and rate applications, and makes submissions in regulatory proceedings.

Table 1: Total A&G Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Treasury	1.37	1.71	1.86	1.93	2.00
Rates	0.82	1.06	1.18	1.13	1.17
Regulatory Affairs	4.54	5.20	8.15	7.79	8.40
Insurance	2.83	2.41	2.87	2.93	2.99
Total	9.56	10.38	14.05	13.77	14.55

* Columns may not sum due to rounding

Table 2: Treasury ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Cost	1.37	1.71	1.86	1.93	2.00

Total treasury costs increase in the bridge and test years primarily due to external services increases related to credit rating, filing and legal fees.

Table 3: Rates ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Cost	0.82	1.06	1.18	1.13	1.17

Consulting fees are expected to be higher in 2007 and 2008 due to the need for external consulting services related to reviewing THESL's Cost Allocation filing, revenue model, and load forecasting model and methodology. Employee expenses (training, conference and travel expenses) increase in 2007 and 2008 to account for increased training, which has been deferred, in previous years. Rates costs are generally static for the years 2008-2010.

Table 4: Regulatory Affairs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Cost	4.54	5.20	8.15	7.79	8.40

Staffing increases account for most of the increase in 2007, as well as consulting and legal fees associated with the preparation of THESL's 2008 EDR Application. Costs in 2008 are higher due to OEB and Intervenor expenses anticipated to cover costs and cost awards associated with the 2008 EDR Application. These costs are expected to be somewhat lower in 2009 but will remain near the 2008 level due to the anticipated costs involved in consultations and hearings related to a number of OEB initiatives over that period. External service costs decline in 2009, but increase in 2010 as additional external support is again used to prepare for the next EDR Application.

Table 5: Insurance ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Cost	2.83	2.41	2.87	2.93	2.99

Insurance expenses, with the exception of 2007, are relatively flat. In 2007, an expected increase in claim costs will be offset by a reduction in THESL's reserve accrual.

DISTRIBUTION EXPENSES ADMINISTRATIVE AND GENERAL

LEGAL SERVICES – INTRODUCTION AND SUMMARY (A&G COSTS)

Legal Services provides strategic direction, leadership and legal advice in respect of a wide variety of legal issues that arise within the company in the areas of corporate/commercial, real property, claims and litigation.

Corporate/Commercial

Legal Services provides legal advice on general corporate polices, procedures and governance and provides legal review, negotiating and drafting of commercial contracts and agreements.

Real Property

Legal Services provides legal advice with respect to real estate matters including reviewing, negotiating and drafting legal documents relating to real property such as offers to connect, supply agreements, easements and real property transactions. It also investigates and responds to easement inquiry letters from prospective purchasers of real property.

Litigation

Legal Services provides legal advice in respect of claims made by, and against, the company, assists in the preparation and filing of statements of claims, statements of defense and related documentation and assists in the defense and prosecution of such matters. It also assists in reviewing, preparing and filing documents relating to insolvency and other collection matters.

Claims

Legal Services assists in the recovery of claims made by the company against third parties for damages to company property and in the processing and defending of claims and related legal proceedings against the company.

In 2006, the lawyers in legal services devoted over 3,700 hours in performing services for THESL which would otherwise have been contracted out to external lawyers. Also, staff in the real property division devoted over 3,100 hours in performing services for THESL which would otherwise have been performed by external personnel.

In 2006 the claims division dealt with over 580 liability claims and 220 property damage claims and recovered over $1.4M.

Table 1: Summary of A&G Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Total	2.49	2.64	2.66	2.75	2.84

1) The 2007 budget for expenses reflects leave of absence, which is not projected for 2008, 2009 or 2010. Excluding that unusual provision, the projected increase in 2007 over 2006 is 2.88 percent.
2) Increases between 2007 and 2008 attributable to anticipated wage increases and general inflation are offset by the elimination of the leave expense.
3) The increases in the test years (2008 through 2010) are the result of anticipated wage increases, general inflation in other costs and the view that, as a consequence of increased capital project work by THESL, legal fees will increase both in the area of contracting for the capital work and the area of raising of capital for the work.

MARKETING, COMMUNICATIONS AND PUBLIC AFFAIRS

INTRODUCTION AND SUMMARY A & G COSTS

Marketing, Communications and Public Affairs is responsible for managing all external and internal communications activities at THESL. Services include communications strategy, public relations, community relations, advertising, news media relations, executive communications, annual report, marketing communications, employee communications, customer relations, issues management, corporate website, extranet and intranet communications and graphic design. Costs in 2006-2010 reflect proactive customer communications in support of market and billing changes and infrastructure improvements.

BUDGET

The Marketing, Communications and Public Affairs expenses for the historical, bridge and test years are shown in Table 1 below.

Table 1: Expenses ($ Millions)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
3.8	3.61	3.88	4.00	4.12

MARKETING, COMMUNICATIONS AND PUBLIC AFFAIRS

Proactive communications help resolve customer problems quickly and help reduce incoming calls to the company, thereby reducing overall operating costs by helping to maintain call centre efficiency and keep construction projects on schedule.

These activities provide customers with information, and access to information, to assist them in understanding new billing systems and rate designs, and investments in local electricity infrastructure improvements.

Customer communications are important for the support of construction projects and a variety of methods are used to keep local residents and businesses informed. These

methods include newsletters and news media releases to raise broad awareness about the projects, thereby reducing public enquiries to THESL's call centre about these activities.

Proactive and reactive media relations are used to communicate information to the public in a timely manner about power outages, electrical safety, consumer issues such as fraud and local investments in the distribution network.

Communications staff is on call 24/7 to provide timely updates to the news media when power outages occur. Staff liaises directly with news reporters until the outage is resolved, providing information on the cause of the outage, the likely duration, and if necessary, appropriate measures to be taken for public safety and protection of equipment. Using a centralized news release distribution service and one point of contact throughout a power outage helps to keep the public informed, reduce operating costs by streaming news reporters to media relations officers rather than system controllers and in certain cases, provides timely information to city public safety (police, fire) and social service agencies that may require such information in order to take appropriate action in the interests of public safety.

Staff interacts directly with customers who require information about the impact of distribution system construction on their property or in their neighborhoods, or who require assistance with some other aspect of their electrical service. Staff updates city councillors and community groups who require information about local projects. Staff is also in direct contact with local business improvement area associations to help them understand how construction may impact area businesses and commerce. Outreach is in the form of one-on-one contact with customers, community meetings, local events and special information sessions or newsletters – all with a view to maintaining open communications and positive community relations. This helps reduce operating costs by

resolving customer issues prior to the commencement of construction and by reducing enquiries that otherwise would come through THESL's Call Centre.

Marketing, Communications and Public Affairs staff also informs customers of changes in their distribution rates, explains the impacts on their electricity bills of new pricing policies, advises of changes in security deposit policies and conditions of service. Staff is also an important source of information to customers on new initiatives such as Smart Meter implementation and Time-of-Use rates. To this end, printed materials such as customer bill inserts or newsletters are often produced for wide distribution to customers, as are detailed customer-specific letters. These activities help to ensure consistent messaging and reduce overall call volumes to THESL's customer care centre. Staff also manages the website and communications material, including "e-bills", which are provided to customers online via the Internet. This helps to reduce the costs associated with printing and mailing and ensures rapid and broad distribution of customer information.

Marketing, Communications and Public Affairs staff is also responsible for providing advice, planning and support for government-directed programs such as conservation and demand management; and smart meters and Time-of-Use rates.

Marketing, Communications and Public Affairs staff is a key conduit between management and employees with respect to the planning, design and production of employee communications. Employee communications help to raise awareness of the importance of workplace health and safety, encourage understanding of key policies and corporate direction, and help to build alignment around strategies and work plans that help to improve operational effectiveness. Staff provides frequent and accurate information on workplace health and safety, corporate strategies and new projects. Frequent, accurate communications help build employee awareness and alignment. The

employee communications function also facilitates the sharing of new ideas, approaches and suggestions among employees across the organization, which can help to lower costs and improve productivity.

COMMUNITY INVOLVEMENT

Community Involvement entails establishing and maintaining relationships with the provincial government and public interest groups involved in commerce, social services, environmental protection, and education. This includes “face-to-face” community relations in support of THESL’s local construction programs, liaising with various groups on local environmental issues, working with schools to provide information, supporting employees by recognizing key service to the company and at special events such as Remembrance Day Ceremonies.

INFORMATION TECHNOLOGY

INTRODUCTION AND SUMMARY OF A&G - MANDATE AND RESPONSIBILITIES

The Information Technology & Services ("IT&S") division provides the systems used by THESL, including billing, engineering and corporate applications support. IT&S delivers the hardware, software, storage and network infrastructure required to run approximately 200 software applications. This includes a mixture of legacy-based systems, standard off-the-shelf software packages and in-house developed products. These applications are critical to the provision of safe and reliable distribution service and the effective operation of THESL's business units.

IT&S' primary mandate is to ensure that THESL's activities are supported in a reliable, timely and cost-effective manner while providing high quality products and services. To meet this mandate, the goals and responsibilities of IT&S are:

- To partner with business units in order to identify and prioritize products and services needed to meet their business goals;
- To build, maintain and enhance an IT governance framework that integrates and institutionalizes good practices in support of the business objectives, by implementing Control OBjectives for Information and related Technology ("COBIT"). This IT industry standard provides a comprehensive framework and processes for the management and delivery of high quality IT-based services;
- To manage and deliver projects, services and major commitments against budget and scope; and
- To provide IT&S staff with the support needed to meet their goals and responsibilities.

Effective January 1, 2007, the IT&S organization was transferred from THC to THESL. At the time of the transfer, IT&S re-aligned its structure from an application-focused service centre to an IT functional focus (refer to Figure 1, IT&S Organization Structure).

The re-alignment has resulted in a more service-oriented focus and more effective and efficient project delivery across the organization, among other improvements. The newly established Governance, Strategy, Security and Portfolio Management frameworks and processes help manage, measure and optimize the realization of business value from the investment in IT, and help with the appropriate management of risk.

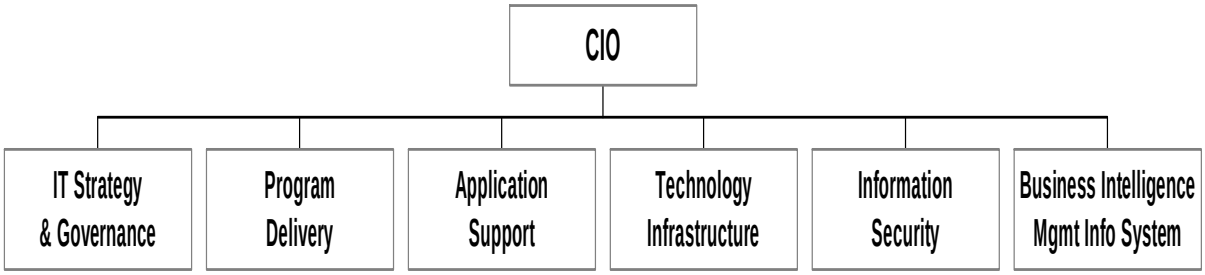


Figure 1: Information Technology & Services Organization Structure

INFORMATION TECHNOLOGY & SERVICES ORGANIZATION

The **IT Strategy and Governance** department is responsible for IT strategy, portfolio management, business planning, regulatory compliance, risk management, internal controls and enterprise architecture. This department has been mandated to develop and implement a governance framework to ensure that IT&S is aligned with THESL's business such that business activities are properly enabled and business benefits are maximized. It is also responsible for gathering and documenting the anticipated quantifiable benefits.

The **Program Delivery** department is responsible for the delivery of all IT-enabled projects. A project office provides project reporting and project measurement using the Application Development framework and Systems Development Life Cycle ("SDLC") process to ensure continuous alignment between IT&S and THESL's business units.

The **Application Support** department provides performance and capacity planning; Service Level Agreement ("SLA") development and management; 2nd and 3rd level application systems support, service and maintenance (issues that are escalated from the 1st level Help Desk); application back-up and recovery planning; critical systems monitoring and engagement of stakeholder groups to understand business unit support needs.

The **Technology Infrastructure** department is responsible for servers, computers, software, telecommunications, radio, internet and other network resources. These include: enterprise and departmental file services; enterprise database and operating systems; web and application servers; enterprise storage; storage area network; network attached storage; 1st level client support (Help Desk service); 2nd and 3rd level technology infrastructure services and back-up and recovery operations.

The **Information Security** department is responsible for the development and enforcement of policies and standards that are related to information security, business continuity and disaster recovery.

The **Business Intelligence and Management Information System** department enables business units to manage their information in ways that help increase efficiency and control costs. This is accomplished by ensuring data completeness, accuracy and validity. This service is provided through the use of the following technologies: business

intelligence and data mining tools, management information reporting tools, data cleansing and transformation tools, data mart and data warehouse.

IT&S allocates a portion of its costs to THESL business units and affiliates based on their use of computers and systems. The allocation is based on usage and includes a depreciation and ROE component as it relates to costs allocated to affiliates. Cost figures shown below are gross and do not include the recovery of allocated costs.

Table 1: IT&S Costs ($ Millions)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Costs	22.65	26.56	28.56	29.59	29.57

2006 TO 2007 VARIANCE EXPLANATIONS

The major variances between 2006 expenditures and the 2007 budget are due to:

- The External & Contract Services increases of close to $3M which are mainly due to:
  - additional software maintenance fees as a result of operation and support of new systems (Outage Management System, Call Center, Ellipse Work Planner, Geo Electric mApping Records ("GEAR"), others); and
  - the external consultants planned to be temporarily brought on board to facilitate the implementation of COBIT.
- The Occupancy and IT Charges increase of $1.1 million
- Increases in payroll costs
- These are partially offset by a decrease in direct purchases of $0.65 million from procurement process improvements implemented within IT&S

2007 TO 2010 VARIANCE EXPLANATIONS

The main contributing factors that lead to operational cost increases between the bridge year and the test years are:

- Staff payroll increases;
- Market inflationary increases on vendor contracts and lease contracts; and
- Operational impact of the major initiatives planned over the next few years.

The main contributing factors that lead to operational cost reductions are:

- Operational process improvements and efficiencies leading to the overall reduction of external staff;
- Application and technology infrastructure consolidation to reduce maintenance contract costs;
- Partnership with external vendors to help reduce hardware purchases and maintenance costs through volume purchases; and
- Re-negotiation of existing contracts to reduce operational costs.

PAYROLL COSTS EXPLANATION

The majority of staff is in the Application Support and Technology Infrastructure departments, performing the daily operational and maintenance functions necessary to operate THESL's business. The balance of the full-time staff is split between Program Delivery, Governance, Security and Business Intelligence. Their mandates revolve around the implementation of new systems, strategy and governance, data security and provision of "smart" data to help the business improve efficiency and financial cost management.

As the organization modernizes over the next few years, many new capital projects are planned. These include Outage Management / Distribution Management Systems ("OMS/DMS"), Mobile Enablement, Customer Information System ("CIS") upgrade and Smart Meter infrastructure to name a few (for a complete list of IT&S Capital Initiatives, refer to Exhibit D1, Tab 10, Schedules 1 and 2). IT&S expects that without any technology and process improvements, such a large increase in workload would result in

an increase in full-time headcount and related payroll cost. However, through consolidation of legacy applications and servers, implementation of enterprise architectures and hardware technologies, the IT&S division does not plan to increase its full-time staff complement.

The anticipated increase in payroll costs are due to annual inflationary pressures and payroll increases expected to occur in 2008, 2009 and 2010.

External & Contract Services

A large portion of IT&S operational costs are allocated to external and contract services. The major expenditure is maintenance contracts for systems that are used daily within the organization.

There are two major categories within External and Contract Services:

1) Maintenance contracts represent a collection of vendor contracts for hardware, software and telephony devices; and
2) Temporary help in the form of fixed services subdivided into consulting, temporary staff, contractors and purchased services.

Maintenance Contracts

Maintenance contract costs show year-over-year increases due to the major capital initiatives that have a significant effect on operational costs. The current on-going projects are Smart Meter, Outage Management Systems / Distribution Management Systems ("OMS/DMS"), GEAR, and CIS upgrade. The projects planned over the test years that also affect operational costs are Mobile Enablement, Service Oriented Architecture ("SOA"), business application enablement, Customer Relationship Management ("CRM"), business intelligence and data management, security, disaster recovery, business continuity and infrastructure refresh.

In order to minimize rising maintenance costs as a result of these initiatives, operational projects are underway to consolidate legacy applications and servers. Other measures being taken to maintain and lower costs are to partner with other external IT businesses in order to increase buying power for hardware devices, which consequently lowers overall maintenance support costs.

Temporary Help

Temporary help represents short term external labour services brought in to augment full-time staff, to back-fill the operations work of staff seconded to capital projects and to increase in-house knowledge by providing particular expertise not currently available internally.

With the various capital initiatives that are planned over the next three years, internal staff will be seconded to these projects in order to develop in-house knowledge while also assisting the Project Delivery team in meeting specific delivery timelines.

When in-house expertise is unavailable, temporary help from consultants is sought. Through this engagement process, the organization benefits because the promised value and benefits are delivered. The internal full-time staff benefit because their expertise is increased by working alongside industry experts. As a result, future projects of a similar nature can be accomplished with fewer or no consultants.

Through internal process improvements and development of internal full-time staff, temporary help costs are expected to decrease annually. By 2010, Temporary Help costs as part of External and Contract Services will have been reduced by more than 40 percent of the current year costs, from $3.57 to $2.02 million in 2010, without increasing full-time staff headcount.

ENVIRONMENT HEALTH AND SAFETY

INTRODUCTION

Environment, Health and Safety ("EHS") provides a range of services in the areas of Environment, Health, Safety and Early Safe Return to Work to ensure that THESL complies with all relevant environmental, health and safety legislation and meets its commitment to provide a safe and healthy workplace for employees. EHS also works to ensure that the company's strategies for achieving sustainable development and growth are successfully met through the development of appropriate EHS programs. A healthy, motivated and engaged workforce is a key driver for the utility's ability to deliver reliable and responsive service.

As THESL begins to ramp up its infrastructure modernization programs, it is also faced with a decrease in experienced trades staff as a result of retirement eligibility. EHS will work with business units to ensure compliance with all relevant EHS legislation and implementation of the appropriate EHS programs in order for THESL to safely meet the demands of the infrastructure modernization programs with a healthy, motivated, trained workforce.

As the organization begins to increase its infrastructure modernization activities, the levels of environment, health and safety risks will increase. To manage this increased risk, EHS will work to identify and address threats to the health and safety of the employees, and the environment. Proactive identification and mitigation of EHS risks will also help to avoid delays in the infrastructure modernization projects.

Three challenges facing THESL and the electricity industry generally are aging assets, an aging workforce and the need to recruit and train new employees. Approximately 50 percent of the potential retirements in the next three to five years will occur in

supervisory, trades and technical positions. These are the employees that deliver distribution service.

The organization is preparing for this transition by hiring additional apprentices within the next three years. The new apprentices will have different needs for EHS programs and training because they lack the experience of the retiring employees. As a result, EHS needs to ensure that the appropriate EHS Programs and work procedures are in place, and that the employees are appropriately trained so that they can work safely, efficiently and ultimately deliver distribution service. Conducting hazard risk analyses and training, and providing appropriate EHS programs and procedures for these new employees will require process improvements in both EHS and the business units.

EHS must constantly work to identify workplace environment, health and safety risks and ensure that it develops and implements appropriate environmental, health and safety programs, work practices and procedures for the ongoing mitigation of these risks. Ensuring that these programs are well communicated and aligned with industry standards is critical for THESL to be able to continue to meet employees' expectations for a healthy and safe workplace, customers' expectations for reliable and responsive service and society's expectations for sustainable development and growth.

EHS Costs

Table 1 below presents the EHS costs for the historical, bridge and test years.

Table 1: EHS Costs ($ Millions)

Line of Business	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Environment	0.59	0.61	0.62	0.64	0.59
Occupational Health	0.52	0.56	0.66	0.72	0.82
Safety	1.46	1.33	1.49	1.48	1.57
Early Safety Return to Work	0.38	0.23	0.46	0.48	0.50
Total	2.95	2.74	3.22	3.34	3.47

* Columns may not sum due to rounding

ENVIRONMENT

The Environment Department contributes to Sustainable Development initiatives by ensuring that THESL complies with relevant environmental legislation and addresses any environmental risks impacting the organization. This is accomplished through administration of the Environmental Assessment Program, the Waste Management Program and the Asset Retirement Obligation.

Activities

Environment performs the following activities:

- Environmental Assessments
- Environmental Program Development and Administration
- Waste Management and Disposal Administration
- Registration of Waste Sites with Ministry of Environment
- ARO – Asset Retirement Obligation, which refers to the legal obligation associated with the retirement of a tangible, long-lived asset, that must be settled as a result of existing or enacted law, regulation, ordinance, contract or other commitment
- Internal Energy Efficiency Program Administration

Costs

Table 2 below presents the Environment Department costs for the historical, bridge and test years.

Table 2: Environment Costs ($000s)

Line of Business	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Environment	0.59	0.61	0.62	0.64	0.59

From 2006 through 2010 the Environment Department costs remain relatively constant with slight variations primarily due to increases due to inflation, offset wholly or in part by decreases in accretion expense.

OCCUPATIONAL HEALTH

Occupational Health Services oversees the disability management process for absences due to occupational and non-occupational illness or injury as well as the administration of THESL's First Aid, Employment Pre-placement Medicals and Wellness programs.

Activities

Occupational Health Services performs the following activities:

- Oversight of the disability management process for absences due to occupational and non-occupational illnesses or injury
- Provision of essential services related to both the work-related and non work-related illnesses and injuries through first aid treatment follow up, referral, medical and emergency care
- Health program development and administration
- First Aid program (First Aid supplies for First Aid rooms, First Aid training)
- Wellness program development and administration

- Pre-placement Medical Exams Co-ordination – Medical conditions that may be aggravated by exposure to designated substances or any other workplace hazard should be detected via pre-placement and periodic follow-up examinations. Pre-placement medical exams provide the employer with a baseline on medical conditions and the appropriate records to ensure the employee is physically able to execute the requirements of his or her position
- Biological Monitoring Administration – Workers, who are exposed to or potentially exposed to Designated Substances (e.g., lead, asbestos and loud noise) are required to undergo a medical surveillance program, outlined in detail in Ontario Regulations 835-846. The objectives of the medical surveillance program are both preventive and remedial. By providing a regular check on workers exposed to lead, asbestos or noise to detect subsequent adverse health effects, the examining physician can alert the employer and the joint health and safety committee to exposure problems in the workplace that might otherwise go unrecognized. This will allow remedial steps to be taken. Legislation requires that this program be conducted at the expense of the employer

Costs

Table 3 below presents the Occupational Health costs for the historical, bridge and test years.

Table 3: Occupational Health Costs ($000s)

Line of Business	2006Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Occupational Health	0.52	0.56	0.66	0.72	0.82

Projected cost increases from 2007 to test year 2008 are attributable to three factors: biological monitoring will be required, the hiring of new apprentices will necessitate pre-

placement exams for new employees and a cost increase is assumed for general inflation. The anticipated cost increase in test year 2009 is attributable to additional professional assistance required due to the anticipated increase in occupational health services to support the increase in aging workforce and employee complement and an increase in costs due to general inflation. The projected test year 2010 cost increase is attributable to biological monitoring required in this year; additional professional assistance required to support the increase in aging workforce and employee complement and an increase for general inflation.

SAFETY

Safety provides strategic direction, leadership and communication to THESL employees regarding safety practices and issues. This includes working with business units to ensure that safety legislative requirements are met; that safety hazards are identified and mitigated and that the appropriate Safety programs are developed to ensure that employees are trained to work safely and efficiently while delivering core service.

Activities

Safety performs the following activities:

- Hazard Risk Analysis and Control
- Program Development and Administration (Electrical Contact Prevention, Confined Space, Fall Prevention)
- Accident Investigations
- Ergonomics
- Safety Legislative Tracking and Reporting
- Safety Management System Development and Administration
- Safety Training
- Safety Performance tracking and reporting
- Safety Benchmarking

Costs

Table 4 below presents the Safety costs for the historical, bridge and test years.

Table 4: Safety Costs ($000s)

Line of Business	2006 Actual	2007 Bridge	2008 Test	2009 Test	2010 Test
Safety	1.46	1.33	1.49	1.48	1.57

Forecast 2007 spending is lower than actual expenditures in 2006 due to safety tools and equipment purchased in 2006, which are not required in 2007. Projected cost increases in test year 2008 through to 2010 are attributable to three factors: funds required for EHS management system development, additional professional services required to ensure appropriate support is provided to the increased workforce and increased cost assumed for general inflation.

EARLY SAFE RETURN TO WORK

The Early Safe Return to Work group administers the Early Safety Return to Work program for both occupational and non-occupational injuries and illnesses.

Activities

Early Safe Return to Work performs the following activities:

- Administration of the Early Safety Return Program for Occupational and Non-Occupational claims
- Worker Accommodation program administration
- Attendance management
- Workplace Safety Insurance Board – Premium performance monitoring and reporting

Costs

Table 5 below presents the Safe Return to Work costs for the historical, bridge and test years.

Table 5: Safe Return to Work Costs ($000s)

Line of Business	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Early Safety Return to Work	0.38	0.23	0.46	0.48	0.50

Forecast 2007 spending is lower than actual expenditures in 2006 due to a $200K rebate anticipated from the Workplace Safety and Insurance Board included in 2007 budget, which is not forecast to occur in subsequent years. Projected cost increases in test years 2008, 2009 and 2010 are attributable to general inflation increases.

ORGANIZATIONAL EFFECTIVENESS

INTRODUCTION

Organizational Effectiveness ("OE") provides a range of services in the areas of organization development; project management and human resources services and planning in support of the Toronto Hydro vision, goals, employees and leaders.

The existing operations include:

- Training and Development Support
- Leadership Development and Succession Planning
- Workforce Planning
- Performance Management System
- Engagement and Change Management Support
- Employee/Labour Relations
- Project Management Support Office/Process Improvement
- Recruitment and Selection
- Benefits Program Design and Management
- Compensation Plans Design and Salary Administration
- Human Resources ("HR") Information Systems
- Co-ordination of Corporate Scorecard Development and Reporting
- Support of Business Planning / Employee Engagement & Communication Process

A skilled and knowledgeable workforce is a critical asset for THESL to allow it to undertake its asset renewal program, while continuing to meet customers' expectations for reliable and responsive service. Due to a significant percentage of retirements in its workforce anticipated in the next three to five years, there is an exceptional and pressing need to develop the organization for the future. Such a significant change in the organization will require excellent leadership to maintain and improve on performance

during this extended period of flux. Between 2007-2014, over 350 employees will reach THESL's average retirement age of 59 with eligibility for an unreduced pension or OMERS Normal Retirement Age 65. This number represents approximately 25 percent of THESL's workforce with over 50 percent of potential retirements occurring in the Supervisory, Trades and Technical positions who deliver THESL's distribution services. For the Trades positions, a 4-1/2 year Apprenticeship is required to achieve full competence. The impact of this attrition begins in 2008. Given the level of turnover expected in the coming years, recruitment, on-boarding[1] and training of these critical resources will require highly efficient processes in both OE and the business units to attract, engage and develop these new employees. OE will be key to the effective integration of the anticipated turnover of staff over the next ten years.

In addition to the integration of new employees and leadership support, the utility's performance will benefit from good governance, good management systems and sound project management of the many initiatives underway in modernizing the utility. OE supports the executive and management team in building these strengths and facilitates the execution of these management processes that will enable the utility to perform as required.

[1] On-boarding refers to a long-term process of bringing new employees into the company; making sure they know what is expected of them and how to add value. Source: Corporate Executive Board

Table 1: OE Division Costs ($ Millions)

Line of Business	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
HR Planning, Benefits and Compensation	0.53	0.87	1.05	1.09	1.13
HR Services (Recruitment/Selection and Labour Relations)	1.24	1.24	1.73	1.84	1.95
Organizational Development & Performance (includes Trades Training Supervisors, Coordinator)	1.19	1.95	2.46	2.59	2.52
Project Support Office	0.35	0.42	0.45	0.46	0.48
OE Total	**3.31**	**4.48**	**5.69**	**5.98**	**6.08**

HR PLANNING, BENEFITS AND COMPENSATION

Summary

HR Planning, Benefits and Compensation is primarily responsible for: providing support for organizational and staff planning; the design and administration of active and retiree benefits programs; design and administration of compensation systems; salary administration; job evaluation; and the management of the Human Resources Information System and reporting requirements. Services include: providing demographic data, analysis, consolidation and management of the operation's short term and long term workforce planning; designing and implementing compensation and benefits programs to attract and retain talent; supporting the design and implementation of HR strategic initiatives aligned with the goals and direction of the operation; designing, assessing and auditing internal HR policies, programs and processes to ensure transparency, effectiveness, adherence to principles and consistency of application; contributing workforce, compensation and benefits data for financial/regulatory reporting.

The demographic profile of THESL's Trades and Technical employee base indicates that well over 350 employees could choose to retire within the next six-to-eight years. To support the capital plan and provide sufficient lead-time for skills development, THESL's 2007 workforce plan calls for hiring more than 60 new employees into Trades and Technical jobs, such as the Line Trade and Designers. From 2008 to 2012, approximately 200 new employees will be hired into these jobs groups. Over 90 percent of the new hires will be deployed to Trades work. With the focus of future hiring on Trades and Technical jobs, management of the workforce plan will be vital to ensuring the required resources are in place as the need occurs.

Costs

Table 2: HR Planning, Benefits and Compensation Costs ($ Millions)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
0.53	0.87	1.05	1.09	1.13

Activities Undertaken as part of the Line of Business

- Demographic Analysis
- THESL ten-year and annual staffing plan
- Organizational Design
- Job Analysis and Job Evaluation
- Compensation Systems Management
- Active Employee and Retiree Benefits Plans Management
- Human Resource Information System Management
- Employee Attendance Analysis
- Human Resources Policies, Procedures and Controls
- Reporting of Human Resources Data for Financial and Regulatory purposes

Table 3: Variance Explanation

From	To	Comments
2006 Historical	2007 Bridge	Expect increased costs due to coverage for leave of absence, job reviews, EDR.
2007 Bridge	2008 Test	Assuming 2.3 percent increase in costs from previous year due to general inflation; assuming benefit contract renewals and initiatives remain same; obtain policy line data and external market data for specific jobs; two additional FTEs.
2008 Test	2009 Test	Assuming 2.4 percent increase in costs from previous year due to general inflation; completion of compensation study.
2009 Test	2010 Test	Assuming 2.1 percent increase in costs from previous year due to general.

HR SERVICES

Summary

HR Services supports employees and leaders in the following primary areas: labour and employee relations; recruitment, selection and on-boarding; job analysis and design; employee performance and attendance management; legislative compliance; and supporting corporate initiatives.

With an aging plant and workforce over the next ten years, HR Services will support organization leaders to significantly increase talent acquisition at an accelerated rate. From 2003 to 2006 HR services supported the organization in the recruitment and selection and on-boarding of 38 apprentices. From 2007 to 2012 HR Services will support leaders in the recruitment and selection and on-boarding of approximately 200 new hires into trades and technical positions.

In 2007, HR Services will focus on talent attraction initiatives, selection and on-boarding to acquire talented employees for the future of Toronto Hydro. Some of the attraction initiatives will include job fairs, partnerships with schools and various other

organizations, career websites, newspapers, community newspapers and various publications to increase the reach of our recruitment activities. Also key to the talent hiring process will be good governance in THESL selection process.

Costs

Table 4: HR Services Costs ($ Millions)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
1.24	1.24	1.73	1.84	1.95

Activities Undertaken as part of the Line of Business

- Job Design
- Talent Attraction Initiatives
- Recruitment and Selection of Full-time, Part-time, Summer and Co-op Students
- On-boarding
- Staff Redeployment
- Employee Performance and Attendance Management
- Employee/Labour Relations Management and associated processes
- Labour Board, Human Rights and Civil complaints, investigations and actions
- Legislative Compliance and Policy Development

Table 5: Variance Explanation

From	To	Comments
2006 Historical	2007 Bridge	Talent attraction initiatives: branding, job fairs, schools, career websites, newspapers, partnerships, publications.
2007 Bridge	2008 Test	Assuming 2.3 percent increase in costs from previous year due to general inflation. One additional FTE HR Services. Additional advertising costs for 20 new hires into trades and technical positions.
2008 Test	2009 Test	Assuming 2.4 percent increase in costs from previous year due to general inflation. Additional advertising costs for 35 new hires into trades and technical positions.
2009 Test	2010 Test	Assuming 2.1 percent increase in costs from previous year due to general inflation. Additional advertising costs for 46 new hires into trades and technical positions.

ORGANIZATIONAL DEVELOPMENT & PERFORMANCE

Summary

Organizational Development and Performance ("ODP") provides support in the following areas: Performance Management Systems, including incentive pay plans, Training and Development Systems, Trades and Technical Training, Leadership Development/Succession Planning, Change Management and Engagement, Consultation and Facilitation, Problem Solving and Strategic Project Support.

With an aging plant and workforce, over the next ten years, ODP will work closely with senior and front line leaders to ensure appropriate investment in the training and development of THESL's employees. ODP will also focus on maximizing opportunities to retain corporate memory as well as setting and maintaining expectations that emphasize THESL's goals and direction.

In 2003, THESL established an in-house Trades School given that basic training for new apprentices was insufficient to maintain safe and efficient operations and satisfactory

customer service in such a diverse distribution territory, supported by changing technology.

Within three years, THESL hired 38 trades apprentices and by 2012, the number of trades and technical apprentices is expected to approach 200. In 2007, ODP assumed responsibility for the development and training of the apprentices. At the same time, Business Transformation assumed responsibility for the apprentice budget and rotation schedule. ODP and Business Transformation are working closely together to ensure the apprentices become fully competent and capable of performing all components of their job to support the safe and efficient operation of THESL's diverse distribution system.

In addition to the Trades School, ODP provides support to the business for assessing and developing technical skills to improve employee productivity, customer understanding and consistency in safety standards.

ODP also supports large-scale engagement and communication forums about the organization's goals and direction, and executes organizational engagement surveys. These events are critical to keeping employees informed about customer expectation and business goals. ODP also provides support on Strategic Projects such as implementing an outage management system and changing nomenclature across the city to build standards.

Table 6: Organizational Development & Performance Costs ($ Millions)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
1.19	1.95	2.46	2.59	2.52

Activities Undertaken as part of the Line of Business

- Training and Development including trades school and technical training
- Performance management and evaluations, including incentive rewards strategies
- Leadership development and Succession Planning

- Team Dynamics and Team building
- Change management, engagement and communication
- Workflow improvement support
- Coordination of annual Business Planning and employee engagement process and events

Table 7: Variance Explanation

From	To	Comments
2006 Historical	2007 Bridge	Change of organizational structure, Trades Supervisors and Coordinator payroll, standby, and communication costs, trades and technical training included in Organizational Development for 2007, increase in development for front line leaders and professionals.
2007 Bridge	2008 Test	Assuming 2.3 percent increase in costs from previous year due to general inflation. $51K increase from 2007 – for training and development as well as change management support.
2008 Test	2009 Test	Assuming 2.4 percent increase in costs from previous year due to general inflation.
2009 Test	2010 Test	Assuming 2.1 percent increase in costs from previous year due to general inflation, Reduction in cost due to completion of training programs in previous years.

PROJECT SUPPORT OFFICE

Summary

The Project Support Office ("PSO") supports Senior Executives in the Business Planning Process. Through this facilitation, the PSO helps to align the Strategic and Business Plans that are undertaken to achieve the goals of the company.

The PSO supports the development of Key Performance Indicators ("KPIs") and scorecard reporting within THESL's Management Control and Reporting System. These are THESL's management tools that provide the operating performance information and

forum for effective management of business processes, enabling appropriate target setting, performance tracking, effective decision-making and direction of the company's resources.

The PSO provides support on Project Management and Project Risk Management on Key Projects undertaken by THESL, such as Geo Electric mApping Records ("GEAR"), Distribution Management System ("DMS") and Customer Information System ("CIS"); these projects deliver improvements to business processes and systems, enabling THESL to modernize and leverage technology for operational advantage. The PSO provides the means for Senior Management to execute appropriate governance over these key strategic and regulatory-mandated projects. The PSO provides "standard" project management training and is the custodian of project tools.

Costs

Table 8: Project Support Office ($ Millions)

2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
0.35	0.42	0.45	0.46	0.48

Activities Undertaken as part of the Line of Business

- Maintenance on Project Management standards and education of project leaders
- Support to the effective use of Project Management tools to ensure project success and good governance
- Facilitation of executive oversight and management of corporate Key Projects portfolio
- Facilitation of business process documentation and improvement
- Education and support of effective utilization of Management Control & Reporting System

- Education and assistance in development of KPIs scorecards and targets for alignment throughout organization
- Support of executive team through their Strategic & Business Planning cycle

Table 9: Variance Explanation

From	To	Comments
2006 Historical	2007 Bridge	Increase based on project management and business transformation initiatives.
2007 Bridge	2008 Test	Assuming 2.3 percent increase in costs from previous year due to general inflation.
2008 Test	2009 Test	Assuming 2.4 percent increase in costs from previous year due to general inflation.
2009 Test	2010 Test	Assuming 2.1 percent increase in costs from previous year due to general inflation.

CONSERVATION AND DEMAND MANAGEMENT ("CDM") PLAN

Introduction

This CDM Exhibit provides the full scope of Toronto Hydro-Electric System Limited's ("THESL") CDM programs to be carried out between 2008 and 2010. In addition to the CDM programs included for this Application, as described in Schedule 2 of this Exhibit, the Ontario Power Authority-funded ("OPA") CDM programs are summarized for information. The Total Resource Cost ("TRC") Test benefit/cost ratios are provided to demonstrate the viability of the CDM programs in this Electricity Distribution Rate ("EDR") application.

Ontario's Minister of Energy authorized electricity distributors to apply to the Ontario Energy Board ("OEB") for the 2005 rate implementation of their third installment of market adjusted revenue requirement ("MARR"), on the condition that an equivalent amount of incremental revenue be invested in conservation and demand management activities ("3rd Tranche CDM") by those distributors. In a letter dated May 31, 2004 to electricity distributors, the Minister further identified some of the activities that might be included in a distributor's CDM Plan ("Plan").

On November 4, 2004 THESL filed with the OEB the Plan as part of the 3rd Tranche CDM funding process. The Plan was based on investing $39.8M in CDM during the period from January 1, 2005 to September 30, 2007. The key thrusts of the Plan were to promote a conservation culture and reduce the summer peak demand in Toronto. The OEB issued its Final Order granting approval of the Plan on February 3, 2005. THESL has since implemented the Plan successfully in accordance with the Board's guidelines. As of the end of 2006, THESL has already achieved peak demand reductions of 62MW and energy savings of 247,344 MWh.

With the 3rd Tranche CDM funding, CDM has become an important part of THESL's core business. Both customers and the distribution system benefit from the results of CDM activities. Customers benefit from the electricity usage savings, and the distribution system benefits from improved reliability achieved through lowering system peak demand. THESL has established a CDM Operation with a base staff of CDM professionals, to operate and maintain the infrastructure to continue to manage and deploy CDM programs, and a demand response center that can activate demand reductions in response to peak demand challenges. It is also evident that Torontonians have responded enthusiastically to the CDM programs rolled out by THESL.

As the 3rd Tranche CDM funding is coming to an end, THESL has been working with the OPA for additional CDM program funding. Under the Government's 300 MW Toronto CDM directive, THESL has entered into an agreement with the OPA to provide transitional funding in 2007 for a number of planned CDM programs and funding for conservation programs in the years 2008-2010, based on a contract signed May 7, 2007 in reference to the Government's directive "Toronto Reliability Supply and Conservation Directive to the OPA". In addition, THESL has received 2007 funding for three of the five OPA standard programs under the $400M LDC CDM directive.

Since the OPA is in its early stage of CDM development, it will fund CDM only on a program-by-program, and on a year-by-year basis. This creates a significant uncertainty not only for the development and planning of future CDM programs, but also as to the on-going maintenance of THESL's CDM operation established under the 3rd Tranche funding. It is critical that THESL continue to maintain and support the CDM technologies and equipment that it has implemented, in order to achieve the full benefits of prior CDM programs. The CDM programs presented in this EDR application are fundamental to ensure the continuity of CDM at THESL.

OBJECTIVES

THESL's overall CDM objectives are as follows:

- To address the electricity peak demand challenge in the City of Toronto;
- To promote a conservation culture among THESL customers;
- To help improve the reliability of the THESL distribution system; and
- To assist THESL customers in managing their electricity usage, especially during peak periods and to implement long-term energy efficiency solutions.

Within the above overall CDM objectives, the goal of the CDM programs included for this Application is to maintain the established CDM operation and infrastructure to ensure the sustainability of CDM at THESL.

CDM PROGRAMS OVERVIEW

There are three major CDM initiative areas, or CDM program portfolios:

Conservation	Programs are deployed to actively engage customers to implement permanent efficiency improvements or become conservation conscious to reduce electricity usage.
Demand Response	Control equipment and devices are installed to allow the customers' discretionary loads to be reduced or turned off during peak demand periods.
Distributed Energy	Renewable generation and standby generators are used to displace loading on the electricity supply system.

The following CDM functional organization has been put in place at THESL to support the three CDM portfolios of activities.

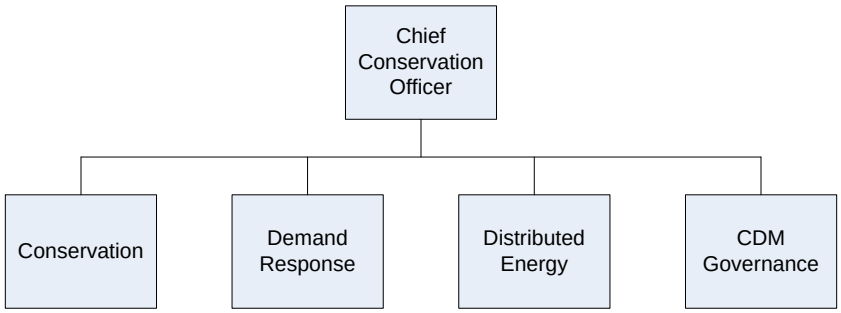


Figure 1: CDM Functional Organization

With funding from the 3rd Tranche and the OPA, programs have been designed in each CDM portfolio to encourage participation from all customer sectors. To ensure CDM programs are carried out with proper control, a governance and management CDM function has been established. CDM control processes have also been developed and implemented for the CDM organization.

For the period 2008-2010, consistent with the OEB report in EB-2006-0266, "Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond", THESL seeks funding from the OPA where there is a relevant OPA program. In areas not covered by the OPA, THESL is seeking funding through distribution rates as follows:

1) The infrastructure necessary for the demand response operation (peaksaver centre and retention of demand response capacities previously acquired);
2) CDM program governance.

The CDM portfolios and the CDM programs within the portfolios included in this Application are as shown in the following table:

Table 1: CDM Portfolios and CDM Programs

Exhibit Schedule	CDM Portfolio	CDM Programs
2	Demand Response	Residential Load Control
3	CDM Governance	CDM Program Governance

The CDM programs included in this Application as well as the CDM programs currently approved by the OPA are summarized in Table 2.

The kW reductions from the Residential Load Control program have not been incorporated into the EDR load forecast because they will have little impact on the distribution revenue. Residential Load Control is a demand response program deployed to address summer peak demand by responding to dispatches from the Independent Electricity System Operator's ("IESO") Emergency Load Reduction Program ("ELRP"). Emergency demand reduction is expected to be activated only a handful of times over the summer period. Moreover, little or no reduction in overall kWh energy consumption is anticipated, since the energy not consumed during the load reduction period will likely be consumed immediately after the control period. The purpose of demand response is to shift load during periods of extreme peak demand. Since the distribution rate of the customers in this program is based on kWh, the impact on distribution revenue will be minimal.

CDM BENEFITS

In addition to supporting the Government's initiative in CDM, THESL's CDM programs have resulted in, and will continue to bring about, benefits to ratepayers as well as the distribution system. Customers in all sectors are involved in THESL's CDM programs, and in the process reduce their electricity usage and become conservation conscious. The reduction in electricity usage during system peak reduces the demand on the distribution system, thereby helping to improve the reliability of the system.

The 50MW Residential Load Control demand response capacity shown in Table 2 for 2008 will have been installed prior to 2008, but will be maintained and controlled using the infrastructure and operational facilities included in this Application. This demand response capacity will be available to help reduce the system peak demand when there is a need to do so. To justify the costs of the infrastructure and operational facilities included in this Application, the total costs used for the TRC Test calculation have included the infrastructure and operational facilities costs for 2008-2010 and the annual recurring costs to 2022, in addition to the costs incurred to establish the 50MW demand response capacity. The TRC Test benefits are the avoided costs related to generation, transmission and distribution for the same period.

The Net TRC Benefit is $44,183,000, which reflects the value of the THESL CDM program in this Application and provides a measure of the net tangible benefit of the CDM program to the society.

It should also be noted that THESL plans to participate in the OPA residential load control standard program in the years 2008-2010. This will result in additional installed demand response capacity for the Residential Load Control program. This additional demand response capacity is not shown because THESL does not have approval from the OPA for the program as yet.

Table 2: Summary of THESL CDM Programs – EDR-funded and OPA-funded ($000s)

Year	Program	Funding Source	OPEX Labor	OPEX Other	CAPEX	Total Cost	Program Annual Savings kw	Program Annual Savings kwh	TRC Net Benefits	TRC Benefit/Cost	
2008	Mass Market	OPA	42	1,833	0	1,875	530	26,633,000	6,150	3.89	
	Social Housing	OPA	42	1,015	0	1,057	420	10,420,000	1,477	1.52	
	Business Incentive Program	OPA	42	2,625	0	2,667	6,670	26,667,000	875	1.26	
	Program Support	OPA	378	455	0	833	N/A	N/A	N/A	N/A	
	OPA Programs Total		504	5,928	0	6,432	7,610	63,719,000	8,502	N/A	
	Residential Load Control	OEB	527	687	385	1,599	50,000	0	44,183	2.22	Note 1
	CDM Program Governance	OEB	261	64	0	326	N/A	N/A	N/A	N/A	
	OEB Programs Total		788	752	385	1,925	50,000	0	44,183	N/A	
	Grand Total		1,292	6,680	385	8,357	57,610	63,719,000	52,685	N/A	
2009	Mass Market	OPA	42	1,833	0	1,875	530	26,633,000	6,150	3.89	
	Social Housing	OPA	42	1,015	0	1,057	420	10,420,000	1,477	1.52	
	Business Incentive Program	OPA	42	2,625	0	2,667	6,670	26,667,000	875	1.26	
	Program Support	OPA	378	455	0	833	N/A	N/A	N/A	N/A	
	OPA Programs Total		504	5,928	0	6,432	7,610	63,719,000	8,502	N/A	
	Residential Load Control	OEB	549	731	491	1,771					Note 2
	CDM Program Governance	OEB	272	66	0	338	N/A	N/A	N/A	N/A	
	OEB Programs Total		822	797	491	2,110	0	0	0	N/A	
	Grand Total		1,326	6,726	491	8,542	7,610	63,719,000	8,502	N/A	
2010	Mass Market	OPA	21	917	0	938	260	13,316,000	3,075	3.89	
	Social Housing	OPA	21	508	0	529	210	5,210,000	739	1.52	
	Business Incentive Program	OPA	21	1,312	0	1,333	3,330	13,333,000	437	1.26	
	Program Support	OPA	189	228	0	417	N/A	N/A	N/A	N/A	
	OPA Programs Total		252	2,964	0	3,216	3,800	31,860,000	4,251	N/A	
	Residential Load Control	OEB	573	811	246	1,631					Note 2
	CDM Program Governance	OEB	284	68	0	352	N/A	N/A	N/A	N/A	
	OEB Programs Total		857	880	246	1,983	0	0	0	N/A	
	Grand Total		1,109	3,844	246	5,199	3,800	31,860,000	4,251	N/A	

Note 1: TRC Test results reflect all the costs for the 2008-2010 Residential Load Control operation and the 50MW demand response capacity installed prior to 2008

Note 2: Residential Load Control program costs for 2008-2010 are reflected in the 2008 TRC Test results

CDM PLAN

DEMAND RESPONSE PORTFOLIO

The objective of the Demand Response program in this Application is to properly maintain and effectively control the already acquired demand response capacities to activate load reductions in response to system emergency needs, or other conditions deemed appropriate by THESL system control, the IESO or the OPA.

TARGET CUSTOMERS

The targeted customers are residential and small commercial.

OVERVIEW

Significant peak demand reduction is achieved by remotely reducing the load cycle of a large number of home and small business central air-conditioners, and turning off the electric water heaters and other non-critical loads during critical peak demand periods. This program is very effective, and is environmentally beneficial since it allows existing generation, transmission and distribution resources to be used more efficiently without requiring any additional investment in generation, transmission or distribution facilities.

Establishing demand response capacity and dispatching demand reductions when needed is a very cost effective way of reducing Ontario summer peak demand, which helps to avoid the import of costly power and thus lower electricity costs in the long run.. With the demand response capacity established, demand reductions can be delivered for durations of typically two to four hours at a time when needed. These reductions can help to prevent the overloading of the distribution system, and allow participating customers who reduce their peak-period demand to benefit from the eventual implementation of Time-of-Use rates.

The capability to reduce electricity demand as necessary makes demand response very effective for addressing peak demand problem. The deterministic nature of the demand reductions through direct control, as verified by Measurement and Verification ("M&V"), also distinguishes demand response from most of the other CDM programs, both in the electricity and gas industries.

It should be noted that the programs in this Application are only for maintaining the demand response capacities already established and for supporting the demand response operation to activate demand reductions. Programs to further expand the demand response capacities are not included in this Application. These programs include the OPA residential load control standard program, which will be implemented when THESL's OPA Application is approved.

BUDGET AND PROGRAM DESCRIPTION

Table 1 shows the Demand Response CDM budget to be funded by EDR.

Table 1: Demand Response Portfolio Budget ($000s)

	2008 Test			2009 Test			2010 Test		
	CAPEX	OPEX	Total	CAPEX	OPEX	Total	CAPEX	OPEX	Total
Demand Response Operation	150	848	998	250	885	1,135	0	967	967
Control Devices Maintenance	225	266	491	231	274	505	236	307	543
Measurement & Verification	10	100	110	10	122	132	10	110	120
Residential Load Control	**385**	**1,214**	**1,599**	**491**	**1,281**	**1,772**	**246**	**1,384**	**1,630**
Demand Response	**385**	**1,214**	**1,599**	**491**	**1,281**	**1,772**	**246**	**1,384**	**1,630**

The CDM program activities to be supported by the budget dollars are explained in the following sections.

Residential Load Control

The THESL direct load control program for residential and small customers, called ***peaksaver ac***, has been very successful. The initial target was 2,600 installations by June, 2006. By the end of 2006 more than 24,000 installations had been completed. The program was also selected by the Government for roll out throughout Ontario.

Significant demand response capacity has already been installed from the 3rd Tranche funding, and, contingent upon OPA funding, additional capacity will continue to be installed. Demand response operation facilities and supporting processes are vital for dispatching, or activating, the demand reductions as and when needed. In addition, there are other program activities necessary to maintain the demand response capacity already

established and to ensure the continued viability of the Residential Load Control program.

Demand Response Operation

Table 2 shows the Demand Response Operation work items and the budget.

Table 2: Demand Response Operation Costs ($000s)

	2008 Test	2009 Test	2010 Test
1) IT software and IT support for systems, network, and load control communications	251	257	263
2) Demand Response center facility and Call Center support	186	190	195
3) Demand Response operation and program management	411	438	459
4) Demand Response systems efficiency enhancements	150	250	50
Total	998	1,135	967

Demand Response Operation for the Residential Load Control program consists of the following:

1) Software and Systems Support

The Demand Response System, to remotely activate the load control devices, is at the heart of the Residential Load Control program. This load control computer system is made up of the load control software, the database, the network on which the software is operated, the pager-network for communicating with the load control devices, as well as the supporting systems used to compute the demand reductions achieved. The Demand Response System is also used for the interactions with the various bodies relevant to demand response, and for monitoring the Ontario electricity supply and demand. The IT systems making up the Demand Response System needs to be maintained, supported and enhanced as requirements arise.

This IT systems infrastructure is necessary to enable the demand response operation to respond expeditiously to demand reduction requirements of the IESO, the OPA, and THESL system control.

2) Demand Response Facility and Call Center Support

The facility is needed to house the demand response operation, and the call center function is necessary to respond to participant issues related to the Residential Load Control program.

3) Operation and Program Management

The most important aspect of the Demand Response Operation is the actual operation and management of demand response activities based on established processes. The work processes are necessary to properly interact with the IESO with respect to the ELRP, the other internal and external parties relevant to the demand response program, as well as the Residential Load Control program participants. The internal parties include the THESL system control operation and customer service. The relevant external parties include the OPA and the media. Interactions with the participants are an important part of the operation, with respect to control device problems and troubleshooting.

It should be pointed out that the demand response dispatching operation is also responsible for dispatching demand reductions for the CII Load Control program.

4) System Enhancements Implementation

It is anticipated that the computer systems for Residential Load Control demand response operation will be enhanced with additional functionalities to make the operation more effective and efficient. As an example, it would be very helpful to

have a computer function that could gather weather forecast information and use it in conjunction with the temperature-time-of-day average load reduction matrices to compute the load reductions for the various load groups for offering to the IESO when there is an emergency demand response notification. Enhancements will also be needed to allow interface to other THESL systems to facilitate the use of demand response for system planning, as demand response capacities attributed to the distribution system feeders and transformers become a resource to support capacity planning.

Control Devices Maintenance

It is anticipated that two to three percent of the devices in the field could fail each year. Maintenance program processes are currently being reviewed and the preferred option will be selected for roll out in 2008 to identify the failed devices and replace them. This is a vital component of the Residential Load Control program. The failed devices need to be replaced in order to retain the level of demand reduction capacity already established.

Measurement &Verification

An integral part of the demand response program is the M&V to determine the demand reduction attained. This M&V is based on a rigorous statistical methodology that requires interval metering be installed at randomly selected sites to measure the result of load control activation. The resulting information is analyzed statistically to determine the average load reduction under different conditions for extrapolation to the population of peaksaver participants.

The sample size needed to achieve the 10 percent accuracy at 90 percent confidence level, and the sample selection method (using the Dahlenius-Hodges, or D-H analysis to determine the strata boundaries) are explained in the M&V Plan submitted to the IESO to support THESL's registration for the ELRP. A coefficient of variation of 0.7, which is

more stringent than the 0.5 suggested by the IESO, has been used to arrive at the sample size of 150.

The kW reduction resulting from the air-conditioner load control has a strong correlation with the maximum temperature of the day. This is distinct from the correlation between the kWh energy savings and the Degree-Day measure. By analyzing the participants' interval meter data between those who are activated and those who are not, for different maximum daily temperatures and different times of day, a matrix is generated with average per participant load reduction under the various conditions. This load reduction matrix is used to determine the demand reduction when all the load control devices are activated, by extrapolation from the statistically significant sample to the population.

Given that new participants are added and some existing participants drop out each year, it is important that random samples be selected to replace the existing samples, and the analysis be performed to update the load reduction information.

CDM BENEFITS

Ontario's summer electricity supply problems typically occur as demand approaches system peak. According to the Provincial system load profile, the top 10 percent of the electricity demand only occurs over approximately 180 hours, or two percent, of the year. Demand response, which allows for a reduction in demand when it is needed, is the most cost-effective way to address this peak demand problem. By reducing sufficient demand during the peak period, tangible benefits are accrued from the avoided generation, transmission and distribution costs from the deferment or even elimination of certain capital expenditures.

After a demand response capacity has been established, and properly maintained, the demand reductions can be activated to derive the benefits year after year. This is the basic purpose of the demand response program at THESL.

Table 4 shows the projection of demand response capacities that will be controlled and the net TRC benefits.

Table 4: Demand Response Portfolio Benefits

	2008 Test			2009 Test			2010 Test		
	kW	Cum. kW	Net TRC Benefit ($000s)	kW	Cum. kW	Net TRC Benefit ($000s)	kW	Cum. kW	Net TRC Benefit ($000s)
Residential Load Control	0	50,000	44,183	0	50,000	-	0	50,000	-

The Residential Load Control demand response capacity for the 2008 season represents the cumulative capacity established from the 3rd Tranche funding as well as the 2007 OPA funding for the program. The Residential Load Control demand response capacity of 50,000kW represents approximately 40,000 residential and small commercial participants. This demand response capacity, along with the demand response operation, is included in the TRC Test, which incorporates all the Residential Load Control program EDR-funded costs in 2008-2010 as well as the costs incurred to install the 50MW capacity. The TRC Test net benefit reflects the value of the Residential Load Control program, including the 2008-2010 EDR-funded work plan for infrastructure, operation, and program maintenance.

The Net TRC benefits, calculated based on the OEB TRC Guide, take into consideration the benefits from the avoided costs of generation, transmission and distribution and all the costs of deployment, including future recurring operational costs, projected for the

life of the load control equipment. An equipment life of 15 years has been used. The Net TRC Test Benefit amount is shown to justify the budget amounts included in this Application.

CDM PLAN

GOVERNANCE

THESL has developed and implemented governance processes for all CDM programs in order to properly control the program activities, ensure integrity of the financial and energy savings of the program and to prepare the necessary program reports for the THESL management and the OEB.

TARGET CUSTOMERS

Even though the customers are not directly impacted by this CDM function, all customers ultimately benefit from CDM programs that are properly controlled through appropriate governance processes.

OVERVIEW

CDM programs typically involve many participants and stakeholders, including customers, service providers and THESL staff. CDM activities involve marketing, enrolment, legal work, contract execution, project control, field installation of devices, dispatch operation, M&V of results, systems support and maintenance of the installed infrastructure. These disparate activities must be properly controlled. In addition, monthly, quarterly and annual CDM reports need to be prepared for THESL management and for the OEB.

To ensure proper governance, THESL requires that an appropriate organization be in place with the accountability to manage and support the various CDM activities including the development and enforcement of governance processes.

BUDGET AND PROGRAM ITEMS

Table 1 shows the 2008-2010 CDM program governance budgets for EDR funding. The 2006 actual and 2007 projection are shown for reference. It is seen that the budgets for EDR funding are significantly lower than the 2006 and 2007 figures. The reason for this is that the 2008-2010 budget dollars only cover the governance costs for the existing CDM programs, and not the CDM programs that will be funded by the OPA. It is anticipated that the OPA funding will provide for program administration and governance.

Table 1: CDM Program Governance ($000s)

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
CDM Admin and Governance	643	535	326	338	352
CDM Program Governance	643	535	326	338	352

Note: All dollars are for OPEX. There is no CAPEX in CDM Governance

CDM Program Governance

The CDM program office provides governance and prepares reports that meet the requirements of THESL management and the OEB. To operate effectively, this program office must be adequately staffed, and equipped with the requisite skills, tools and processes to provide proper administrative control and on-going support.

The responsibilities of the CDM Programs Governance group include the following:

- Developing and maintaining administrative, financial tracking and governance processes;
- Administering the governance and control processes to ensure adherence to company and OEB rules, regulations, terms, conditions and accounting policies and practices;

- Preparing and verifying of monthly, quarterly, and annual reports for THESL Executives, Board of Directors, and the OEB;
- Developing and controlling of project tracking processes and infrastructure
- Providing support in project approval process;
- Tracking and validating all the financial transactions, including invoices and payments, against the relevant supporting documents;
- Performing the various calculations, including the TRC Tests, for CDM projects;
- Performing internal audit of CDM energy benefits/savings and financial results;
- Supporting external audits of CDM programs and results;
- Providing support to regulatory groups and processes;
- Providing financial-related and general support for each CDM program and overall CDM portfolio; and
- Overseeing the development and submission of the work plan budgets to funding agencies.

CDM BENEFITS

Governance procedures and processes are implemented and enforced to ensure CDM programs are properly controlled and managed.

TAXES AND PILS

INTRODUCTION

The revenue requirement in this application reflects an amount for Payments in Lieu of Taxes ("PILs") recovery of $40,850,253 for 2008, $39,469,707 for 2009 and $38,100,719 for 2010. THESL has employed a model based on the 2006 Ontario Energy Board ("OEB") Tax Model with some adjustments such as appropriate income tax rates for each of 2008, 2009 and 2010 to compute PILs amounts. The basic computations, methodology, principles and detail of the 2006 OEB Tax Model have been followed, but modified as necessary for the three test years.

PRUDENT MANAGEMENT OF PILS/TAXES

The amount of PILs paid by THESL in any given year is tied to net income. As such, the relative magnitude is based on the profitability of THESL. However, THESL manages its tax costs diligently in an effort to keep the effective rate of tax as low as possible. A dedicated group of tax personnel administers the taxes and ensures that the PILs are managed prudently. The company takes advantage, where it can, of available tax deductions and tax credits, such as research and development tax credits, to minimize its tax burden.

REGULATORY TAXES EXPENSE METHODOLOGY

The tax amounts calculated by THESL for inclusion in rates for the 2008, 2009 and 2010 years represent taxes payable for the stand alone distribution-only business. The regulatory taxes computed are based upon the principles set out in Chapter 7 of the Electricity Distribution Rate Handbook ("DRH").

TAX MODEL BASED ON THE 2006 OEB TAX MODEL FOR FORWARD TEST YEAR ("FTY")

As THESL is filing on a FTY basis, the following variations from the 2006 OEB Tax Model have been made:

- Adjustments in reconciling net income for accounting purposes to taxable income are based on projected results for 2008, 2009 and 2010. Only material adjustments have been included.
- Capital cost allowance is computed based on an estimated 2008, 2009 and 2010 Schedule 8, filed at Exhibit P1, Tab 1 (Schedule of Capital Cost Allowance). Projected capital additions for 2008, 2009 and 2010 are used. A separate computation of 2007 capital cost allowance is performed to derive 2008 opening balances that reflect projected 2007 capital additions. Maximum capital cost allowance is taken for 2007 and for each of 2008, 2009 and 2010.
- The cumulative eligible capital deduction for each of 2008, 2009 and 2010 is calculated for each specific year. Maximum cumulative eligible capital deductions are taken for all years.

Schedule 1 (Calculation of Net Income (Loss) for Income Tax Purposes) adjustments

- For 2008 to 2010, tax adjustments are made on Schedule 1 only for material items that can be reasonably expected to be incurred in the test year. For example, no add back is made for non-deductible meals and entertainment. Historically this amount has been small relative to taxable income.
- Material changes in reserves are not expected in the test years except for accrued employee future benefits and the general reserve for bad debts. These reserves are included on Schedule 13 (Continuity of Tax Reserves) of the tax model for each of 2008, 2009, and 2010.

DISCLOSURE OF PILS TAX ADMINISTRATION AND TAX RULINGS

THESL has not received any specific tax rulings or assessment policy that is inconsistent with the 2006 OEB Tax Model.

TAX RE-ASSESSMENTS

The Ministry of Finance has not yet completed its review of any of the THESL tax returns for prior tax years. Therefore, the 2008, 2009 and 2010 PILs amounts computed for inclusion in the 2008, 2009 and 2010 EDR do not contain any adjustments resulting from a reassessment of PILs of a previous year.

PRINCIPLES APPLICABLE TO SPECIFIC COMPONENTS OF THE CALCULATION

THESL has followed the 2006 OEB Tax Model to calculate PILs with appropriate legislative changes such as corporate and capital tax rates and capital cost allowance rates.

TAX TREATMENT OF DIVIDENDS PAID IN PRIOR YEARS

Dividends were paid in the preceding three years. The dividends were treated as payments out of tax paid retained earnings and therefore were not treated as deductible for tax purposes.

NON-RECOVERABLE AND DISALLOWED EXPENSES

There are no non-recoverable expenses reflected in the 2008, 2009 and 2010 EDR Model. Hence, no adjustment is required in respect of non-recoverable expenses for the 2008, 2009, 2010 regulatory tax calculations.

CAPITAL TAX EXEMPTIONS

As THESL is the only regulated entity in the Toronto Hydro corporate group, the Ontario capital tax computations for THESL take into account the full Ontario capital tax exemptions available. No federal large corporations tax is computed as this was eliminated in 2006.

Computations of the Ontario capital tax are made based on projected balance sheet amounts. For comparison purposes, a computation of the Ontario capital tax based on the applied-for rate base is also presented. The greater of the two methods is used as the tax input in the applicable test year's EDR Model revenue requirement calculation.

LOSS CARRY-FORWARDS

THESL has no non-capital or capital loss carry-forwards at the end of December 2006, and does not expect to have such loss carry-forwards at the end of December 2008, 2009 and 2010.

THESL's only business within its legal entity is an electricity distribution business. Accordingly, Schedule 7-1 (Continuity of Loss Carry-Forwards) is neither applicable nor included as part of this application.

UNDEPRECIATED CAPITAL COST ("UCC") AND CAPITAL COST ALLOWANCE ("CCA")

As THESL is filing this application using an FTY basis, CCA is computed for 2008, 2009 and 2010 based on projections of the change in capital assets over the 2007 to 2010 years. A separate Schedule 8 is prepared to compute CCA for 2007 and to derive the projected undepreciated capital cost balances at January 1, 2008. In doing this, maximum CCA is claimed in 2007. Maximum CCA is also claimed in the 2008, 2009 and 2010

PILs tax models. As well, any additions projected for 2007 through 2010 are subjected to the half-year rule.

The PILs regime came into effect on October 1, 2001 at which time THESL was deemed to have commenced a new taxation year for purposes of determining its liability for PILs. Accordingly, THESL was deemed to have disposed of its assets at its then fair market value and to have reacquired such assets at the same amount. The difference between the financial statement carrying value and the tax basis of assets is referred to as the fair market value "bump". The effects of the 2001 fair market value "bump" are reflected in the 2007, 2008, 2009 and 2010 CCA computations.

Attached is Schedule 7-2 (October 2001 FMV Adjustment) filed at Exhibit P1, Tab 1, that provides information relating to the fair market value "bump". Also attached is a supplementary schedule to Schedule 7-2, filed at Exhibit P1, Tab 1, Schedule 1 that provides information on the remaining dollar value of the increase or decrease of the "bump" at December 31, 2010.

There is a difference for accounting and tax purposes with respect to the fair market value "bump" as no bump was recorded for accounting purposes. Schedule 7-2 provides information on the "bump" for tax purposes only.

REGULATORY TAX TREATMENT OF ELIGIBLE CAPITAL EXPENDITURE ("ECE")

As with the amount of CCA on depreciable capital property included in the PILs tax calculation, the amount of cumulative eligible capital deduction is based on the projected balance of cumulative eligible property in 2008, 2009 and 2010. A separate completed Schedule 10 for the 2007 year is used to derive the 2008 opening balance of cumulative eligible capital. The 2009 opening balance follows from the 2008 closing balance and

similarly the 2010 opening balance follows from the 2009 closing. Maximum cumulative eligible capital deduction is claimed for all years.

The cumulative eligible capital used in the computation includes the October 1, 2001 fair market value "bump".

Schedule 7-2 provides details of the fair market value "bump" for undepreciated capital cost and eligible capital property.

INTEREST DEDUCTION

Actual interest expense is less than the deemed interest expense calculated by the EDR Model for 2008, 2009 and 2010. Therefore actual interest expense has been used in the calculation of PILs in the Tax Model.

CAPITALIZED INTEREST

Interest is not capitalized to construction work in progress for tax purposes. However, interest is capitalized for accounting purposes in 2008 through 2010 projections.

Attached is a completed Schedule 7-3 (Interest Expense), filed at Exhibit P1 Tab 1, Schedule 1 that details the derivation of relevant interest calculations.

NON-DISTRIBUTION ELIMINATION

THESL's business is solely the distribution of electricity and thus there are no adjustments to arrive at wires only figures.

TAX CREDITS

THESL expects a level of expenditure similar to that of prior years to qualify for research and development tax credits in the years 2008 to 2010. Estimated investment tax credits

arising out of expenditures on qualifying Scientific Research and Experimental Development projects carried on by THESL in 2005 and 2006 equal approximately $200,000 per year. This represents estimated qualifying expenditures (after including a proxy for overhead) of $1,000,000 per year at an investment tax credit rate of 20%. Expenditures before overhead proxy are estimated at approximately $610,000.

CAPITAL LEASES

No capital leases capitalized for accounting purposes are deducted for tax purposes.

TAX PAYABLE FILINGS

Details of actual taxes paid by THESL from 2004 to 2006 are outlined in the table below as well as the forecasted taxes to be paid from 2007 to 2010. Explanations of the variances for the forecasted years are provided below.

Table 1: Summary of PILs by Year ($ Millions)

	2004 Historical	2005 Historical	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Income Taxes	39.2	57.2	52.6	33.8	35.3	34.7	34.7
Capital tax	5.8	5.8	6.1	5.8	5.6	4.8	3.4
Total PILs	45.0	63.0	58.7	39.6	40.9	39.5	38.1

2006 to 2007

The decrease in PILs of approximately of $19.1M is mainly due to a decrease in income before taxes, and differences between the tax and book treatment of various costs.

2007 to 2008

The increase in PILs of approximately $1.3M is mainly due to an increase in income before taxes, and differences between the tax and book treatment of various costs.

2008 to 2009

The decrease in PILs of approximately $1.4M is mainly due to a reduction in capital taxes due to a reduction in the capital tax rate and differences between the tax and book treatment of various costs.

2009 to 2010

The decrease in PILs of approximately $1.4M is mainly due to a reduction in capital taxes due to a further reduction in the capital tax rate and differences between the tax and book treatment of various costs.

REVENUE OFFSETS

INTRODUCTION

The purpose of this evidence is to present THESL's Revenue Offsets.

THESL earns revenue from its distribution tariff. THESL also earns other revenues from non-distribution related services, from rentals and from short-term investment income. These other revenues are used to offset the revenue requirement to be collected through the distribution tariff.

THESL's forecast of Other Revenue Offets is summarized as follows:

Table 1: Other Revenue ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
24.5	30.9	30.5	26.3	21.7	24.3

RATES AND CHARGES

THESL follows the 2006 EDR definition and has divided Other Revenue into the following categories:

- Revenue from Specific Service Charges including Pole Attachment
- Late Payment Charges
- Other Distribution Revenue
- Other Income and Deduction

Revenue from Specific Service Charges including Pole Attachment

THESL charges user fees for certain services. Some of these services, such as Account Setup, are provided at customers' request. Others result from THESL's business operations, such as collection fees resulting from customers' non-payment of bills.

In the 2006 EDR, THESL adopted the OEB-approved charges for services for which a fee is applicable. In 2006, the OEB also provided a formula to determine a standard, province-wide pole attachment rate of $22.35 per pole per year.

THESL proposes no change to the Specific Service Charges and Pole Attachment Rates in the current application as shown in Exhibit I1, Tab 1, Schedule 2.

Specific Service Charges

The detailed breakdown of the Specific Service Charges for 2006 to 2010 is presented in Exhibit I1, Tab 1, Schedule 3 and the total for each year is summarized as follows:

Table 2: Specific Service Charges ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
5.4	4.3	5.3	5.9	6.0	6.2

Actual Specific Service Charges in 2006 are lower than the Approved 2006 EDR amount by $1.1 million. This is mainly because the new Specific Service Changes were effective May 1, 2006 and the full impact of the rate increases were not realized until 2007.

For the same reason, the 2007 bridge year revenue is higher than the 2006 actual.

In the test years 2008 to 2010, the increase in Specific Service Charges is driven by the expected increase in the number of customers resulting from the conversion of bulk-metered apartment buildings to individually-metered suites. THESL does not charge newly initiated accounts for Account Setup, but does for subsequent change of occupancy. It is estimated the customers initiated in 2008 will result in an increase in Account Setup Charges of $117,000 in 2009. Similarly, the customers initiated in 2008 and 2009 will result in an increase of Account Setup Charges of $273,000 in 2010.

Based on the upward trend observed in collection activities in the first few months of 2007 and the expected increase in the number of customers and related collection activities, Collection Charges are projected to increase to $2.5 million in 2008.

Pole Attachment

In 2006, the OEB provided a formula to determine a standard, province-wide pole attachment rate of $22.35 per pole per year. THESL also has a number of poles for which the fees fall under reciprocal joint use agreements with third parties. The rates for joint use of poles are negotiated rather than based on the OEB-approved rates.

Table 3: Pole Attachment ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
1.4	1.7	1.5	1.5	1.5	1.5

In 2008 to 2010, Pole Attachment will generate approximately $1.5 million each year. The increase in the 2006 Actual is related to the timing of billing by third parties.

Late Payment Charges

THESL proposes to continue charging a 1.5 percent per month (19.56 percent per annum) penalty for late payments. The annual Late Payment Charges are summarized as follows:

Table 4: Late Payment Charges ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
4.6	4.6	4.1	5.0	5.0	5.0

Revenue from Late Payment Charges has averaged approximately $4.6 million per year. THESL's 2006 actual Late Payment Charges of $4.6 million matched the Approved 2006 EDR amount.

In 2007, Late Payment Charges were forecast to decrease. Furthermore, there is an expected increase in the number of customers resulting from the conversion of bulk-metered apartment buildings to individually-metered suites. As a result, Late Payment Charges are projected to increase to $5 million in the test years 2008 to 2010.

Other Distribution Revenue

Other Distribution Charges include revenues from RPP Administration Charges and Retail Service Charges as defined by the OEB in the 2006 Distribution Rate Handbook. Rental incomes derived from THESL properties such as Duct Rental are included in Other Distribution Revenue.

A detailed breakdown of the Retail Service Charges is presented in Exhibit I1, Tab 1, Schedule 4 and summarized as follows:

Table 5: Other Distribution Revenue ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
9.7	8.2	7.2	6.7	6.9	7.2

The 2006 Actual Other Distribution Revenue is lower than the 2006 EDR amount by $1.5 million. The variance is mainly attributed to the following charges:

Table 6: Comparison of Other Distribution Revenue ($ Millions)

Description	Approved 2006 EDR	2006 Historical	2006 Historical vs. Approved 2006 EDR	Drivers
Retailers' Variable Charge	0.9	0.6	(0.3)	Decrease in retailers' customers
LDC Consolidated Billing	0.5	0.3	(0.2)	Decrease in retailers' customers
Other Retailers' Service Fees	0.4	0.1	(0.3)	Decrease in retailers' customers
RPP Admin Charge	1.7	1.8	0.1	Retailers' customers switching back to RPP.
Duct Rental	4.8	3.3	(1.5)	Contracts renewed under updated terms
Interval Meter Telephone Charges	0.4	0.6	0.2	More customers converted to interval meters
Stale Dated Cheques	0.3	0.5	0.2	More rebate cheques being issued

There is a decrease of $1 million in Other Distribution Revenue in 2007. This is due to a further decrease in the number of retailers' customers, a decrease in settlement discounts and a decrease in stale dated cheques.

The 2008 decrease in Other Distribution Revenue is due to the following changes:

- THESL discontinued its water meter reading service in 2007, resulting in a decrease of $0.3 million in service revenue.
- THESL proposes to eliminate telephone charges for customers with interval meters, resulting in a $0.6 million drop in Interval Meter Telephone Charges in 2008. The costs will be recovered from the customer charges of the applicable customer classes. This is consistent with the way smart meters costs are recovered from the other customer classes.
- A projected increase of $0.2 million in settlement discounts.
- A projected increase of $0.2 million in Duct Rental.

Other Income and Deductions

Table 7: Other Income and Deductions ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
3.3	12.1	12.5	7.3	2.3	4.4

THESL earns revenue by providing services to customers and third parties, earns interest income from short-term investments of its idle cash balances and earns revenue from gains on the sale of scrap metal and from disposal of utility properties.

Further details on these revenue sources are presented in Exhibit I1, Tab 1, Schedule 5 and discussed in the following section.

Merchandise and Jobbing

Some THESL business units provide services to customers and third parties for a fee. The charges are based on fully burdened labour, material and vehicle rates. The main services include the following:

- customer requests for isolation, protection and temporary removals of lines
- providing standby personnel when third parties perform work on facilities located within THESL properties and plants
- Maintenance of third party facilities located within THESL property
- Income generated from the sale of scrap metals inventory

Table 8: Merchandise and Jobbing ($ Millions)

	Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Revenue	8.9	12.0	8.2	9.3	9.4	9.5
Expenses	(8.6)	(9.3)	(6.7)	(6.8)	(7.0)	(7.2)
Net Revenue	0.3	2.7	1.5	2.5	2.4	2.2

The 2006 Actual net revenue of $2.7 million was higher than the amount of $0.3 million projected for the 2006 EDR. The revenue from Merchandise and Jobbing depends on the number and type of the activities in the year. Some activities may generate a higher margin. For example, scrap metals are sold in the market and could yield a profit. The profit depends on the strength of the market, the US dollar exchange rate, and on how much scrap is available for processing.

For the test years, 2008 to 2010, THESL projects net revenue of about $2.4 million per year based on various business units' forecast of revenues and cost.

Gains from Sale of Utility Properties

THESL expects to dispose of several properties in 2007 to 2010. The sale of properties is discussed in more detail in Exhibit C2, Tab 2, Schedule 2 and the gains are summarized as follows:

Table 9: Gains from Sale of Utility Properties ($ Millions)

	Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Gains on Sale		0.6	11.8	0.8	0.0	3.9
50% Gains on Sale		0.3	5.9	0.4	0.0	2.0

Based on the OEB's usual approach, THESL proposes the gain will be shared between the ratepayers and the shareholders on a 50/50 basis in the determination of the Revenue Offsets.

Interest Income from Short Term Investment

THESL actively manages idle working capital cash balances by investing excess cash in low risk Canadian and U.S. money market instruments. This activity provides a dual benefit. First, the interest earned from cash management offsets THESL's long-term and short-term interest expense, thereby increasing its interest coverage ratios. This helps to maintain THC's investment-grade credit rating, which in turn has the pecuniary benefit of allowing THESL to post lower prudentials with the IESO, and to arrange short-term borrowings at more favourable rates, as necessary. Secondly, since the interest earned from investments is an offset to overall distribution revenue, other things being equal, ratepayers benefit from lower overall rates than in the absence of such a revenue offset.

Table 10: Interest on Short Term Investment ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
3.1	8.7	5.0	4.4	(0.1)	0.2

The interest income will depend on the amount of available cash in the year. In the 2006 EDR, it was assumed that THESL would have needed to rebalance its capital structure to its deemed 65-percent-debt to 35-percent-equity structure. Instead, given the significant capital requirement forecast over the next ten years, management decided to draw down THESL's cash balances prior to accessing debt capital markets for new borrowings. This resulted in THESL retaining its working cash balances which generated an additional interest income of $5.6 million in 2006.

Because of the significant increase in capital spending over 2008 to 2010, available cash will decrease and interest income will fall accordingly.

Applicable Specific Service Charges

Table 1

	Col. 1	Col. 2
1	**Description**	**OEB Standard Rate ($)**
2	Account Setup/Change on Occupancy Charge	30.00
3	Collection of Account Charge - no disconnection	30.00
4	Disconnect/Reconnect at Meter - after hours	185.00
5	Disconnect/Reconnect at Meter - regular hours	65.00
6	Disconnect/Reconnect at Pole - after hours	415.00
7	Disconnect/Reconnect at Pole - regular hours	185.00
8	Duplicate Invoices for Previous Billing	15.00
9	Easement Letter	15.00
10	Income Tax Letter	15.00
11	Install/Remove Load Control Device - after hours	185.00
12	Install/Remove Load Control Device - regular hours	65.00
13	Meter Dispute Charge plus Measurement Canada fees (if meter found correct)	30.00
14	Returned Cheque Charge (plus bank charges)	15.00
15	Special Meter Reads	30.00
16	Specific Charge for Access to the Power Poles $/pole/year	22.35

Revenue from Specific Service Charges ($000s)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	**Description**	**Approved 2006 EDR**	**2006 Historical**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
2	Set Up Charge	2,850	2,162	2,800	2,800	2,917	3,073
3	NSF Collection Charges	120	103	100	100	100	100
4	Collection Service Charges	1,800	1,709	2,000	2,500	2,500	2,500
5	Connection-Reconnection Charge	568	314	400	490	490	490
6	Special Meter Read	30	-	5	5	5	5
7	Duplicate Invoices for Previous Billing	15	-	-	-	-	-
8	Easement Letter	18	0	-	-	-	-
9	Income Tax Letter	15	0	5	8	8	8
11	**Total Specific Service Charges**	**5,416**	**4,287**	**5,310**	**5,903**	**6,020**	**6,176**

Other Distribution Revenue ($000s)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	**Description**	**Approved 2006 EDR**	**2006 Historical**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
2	Retailers' Fixed Charge	3	3	-	3	3	3
3	Retailers' Variable Charge	869	579	500	500	500	500
4	LDC Consolidated Billing	498	330	300	300	300	300
5	Retail Consolidated Billing	- 24	- 17	- 16	- 16	- 16	- 16
6	Service Transaction Request	4	29	25	25	25	25
7	Service Transaction Processing	2	24	20	20	20	20
8	Other Retailers' Service Fees	412	131	140	140	140	140
9	RPP Admin Charge	1,654	1,804	1,800	1,800	1,890	2,010
10	TTC Rectification	304	304	300	300	300	300
11	Duct Rental	4,795	3,320	3,263	3,408	3,556	3,707
12	Miscellaneous Rent and Revenue	64	40	-	-	-	-
13	Interval Meter Telephone Charges	448	633	550	-	-	-
14	Settlement Discounts Taken	153	206	-	180	180	180
15	Stale Dated Cheques	286	530	-	-	-	-
16	Water Meter Reading	240	306	300	-	-	-
17	**Total Other Distribution Revenue**	**9,706**	**8,222**	**7,182**	**6,660**	**6,898**	**7,169**

Other Income and Deductions ($000s)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	Description	**Approved 2006 EDR**	**2006 Historical**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
1	Merchandise and Jobbing Revenue	8,917	11,963	8,236	9,288	9,375	9,465
2	Merchandise and Jobbing Expenses	(8,650)	(9,270)	(6,689)	(6,790)	(7,005)	(7,241)
3	Net Merchandise and Jobbing Revenue	267	2,693	1,547	2,498	2,370	2,224
5	Gain/Loss on Disposals		299	5,878	393	20	1,970
6	Interest Income	3,057	9,086	5,036	4,380	(88)	221
7	**Other Income and Deductions**	**3,324**	**12,078**	**12,461**	**7,271**	**2,302**	**4,415**

REVENUE REQUIREMENT AND SUFFICIENCY / DEFICIENCY

This evidence provides a summary of the revenue required by THESL to continue to provide safe and reliable service to its customers.

THESL earns the majority of its revenue through the distribution tariff and earns other revenues through the provision of non-distribution related activities. These other revenues offset the required revenue to be collected from THESL's distribution service customers.

The recovery of Regulatory Assets is not included in the revenue requirement. Regulatory Assets are recovered through a separate rate rider. Regulatory Assets, deferral accounts and recoveries are explained in Exhibit J1, Tab 1, Schedule 2.

SERVICE REVENUE REQUIREMENT

Service Revenue Requirement is comprised of distribution expenses, cost of capital and PILs.

The distribution expenses, consisting of OM&A, depreciation and amortization, and property taxes are explained in further detail in Exhibits D1, F1 and F2. A summary of distribution expenses is contained in Exhibit J1, Tab 2, Schedule 1.

Cost of capital is calculated based on a weighted average of interest expense and return on equity. THESL's capital structure for ratemaking purposes is determined in accordance with the OEB's Cost of Capital guidelines issued on November 30, 2006 as explained in Exhibit E1, Tab 1, Schedule 1. The cost of capital based on the Board's deemed capital structure is calculated in Exhibit J1, Tab 2, Schedule 2. Income Taxes and PILs are explained in detail in Exhibit H1, Tab 1, Schedule 1.

The calculation of Service Revenue Requirement is contained in Exhibit J1, Tab 2, Schedule 3 and summarized as follows:

Table 1: Service Revenue Requirement ($ Millions)

	Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Distribution Expenses	288.6	294.0	304.0	349.7	367.3	388.2
Interest Expense	62.7	61.3	66.1	68.6	71.5	76.9
Return on Equity	58.6	57.3	58.2	65.5	77.5	83.5
PILS	46.7	46.0	39.5	40.9	39.5	38.1
Service Revenue Requirement	456.6	458.6	467.9	524.7	555.7	586.7

REVENUE OFFSETS

THESL earns revenue from its distribution tariff as well as other revenues from non-distribution related services, rentals and short term investment income. These other revenues are used to offset the revenue requirement to be collected from the distribution tariff.

Forecast of Other Revenues are explained in detail in Exhibit I1, Tab 1 and summarized as follows:

Table 2: Revenue Offset ($ Millions)

Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
24.5	30.9	30.5	26.3	21.7	24.3

BASE REVENUE REQUIREMENT

Since THESL collects revenues from sources other than distribution charges, these other revenue sources must be removed from the Service Revenue Requirement in order to determine the base revenue to be collected in the distribution tariff.

Base Revenue Requirement is Service Revenue Requirement less Other Revenue Offset and determined for the years 2008, 2009 and 2010 as follows:

Table 3: Base Revenue Requirement ($ Millions)

	Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Service Revenue Requirement	456.6	458.6	467.9	524.7	555.7	586.7
Other Revenue Offset	24.5	30.9	30.5	26.3	21.7	24.3
Base Revenue Requirement	432.1	427.7	437.4	498.4	534.0	562.4

The Base Revenue Requirement is allocated and collected from the various customer classes through distribution rates.

OVERALL REVENUE DEFICIENCY

Revenue deficiency/sufficiency is determined as the difference between revenue at current rates (before rates are adjusted to recover the required revenue), and service revenue requirement for a specific test year.

For example, 2008 revenue (at current rates) is calculated based on the 2008 forecast of sales quantities and at the 2007 approved rates. 2009 revenue (at current rates) is calculated based on the 2009 forecast of sales quantities and at the 2008 proposed rates.

2010 revenue (at current rates) is calculated based on the 2010 forecast of sales quantities and at the 2009 proposed rates.

The 2008 to 2010 revenue calculations are shown in Exhibit M1, Tab 3, Schedule 1, Schedule 2 and Schedule 3, respectively.

Gross revenue deficiency is determined by subtracting Service Revenue Requirement from Total Operating Revenue. THESL's gross revenue deficiencies are forecast as follows:

Table 4: Gross Revenue Deficiency ($ Millions)

	2007 Bridge	2008 Test	2009 Test	2010 Test
Sales Revenue at Current Rates and Other Revenue	464.1	463.0	525.9	566.5
Service Revenue Requirement	467.9	524.7	555.7	586.7
Gross Revenue Deficiency = Revenue at Current Rate minus Service Revenue Requirement	(3.8)	(61.7)	(29.8)	(20.1)

Detailed calculations for the indicated and requested rate of return, and the gross and net revenue deficiencies are shown in Exhibit J1, Tab 2, Schedule 4. Utility net income is shown in Exhibit J1, Tab 2, Schedule 5.

CAUSES OF REVENUE DEFICIENCY

The detailed calculations are contained in Exhibit J1, Tab 2, Schedule 6 and summarized in Table 5 and Table 6, below.

Table 5: Summary of the Components of Revenue Deficiency ($ Millions)

	Approved 2006 EDR	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
OM&A Including Municipal and Property Taxes	161.7	169.4	171.6	196.0	206.5	213.8
Depreciation and Amortization	126.9	124.6	132.4	153.7	160.9	174.4
Interest Expense	62.7	61.3	66.1	68.6	71.5	76.9
Return on Equity	58.6	57.3	58.2	65.5	77.5	83.5
PILs	46.7	46.0	39.5	40.9	39.5	38.1
Service Revenue Requirement	456.6	458.6	467.9	524.7	555.7	586.7
Distribution. Revenue at Current rates	432.1	425.5	433.6	436.7	504.2	542.2
Other Revenue	24.5	30.9	30.5	26.3	21.7	24.3
Total Operating Revenue	456.6	456.3	464.1	463.0	525.9	566.5
Gross Revenue Deficiency	0.0	(2.2)	(3.8)	(61.7)	(29.8)	(20.1)

Table 6: Summary of Components of Rate Base ($ Millions)

	Approved 2006 EDR	2006 Historical*	2007 Bridge**	2008 Test**	2009 Test**	2010 Test**
Net Fixed Assets	1,553.4	1,526.5	1,584.4	1,712.2	1,870.2	2,000.3
Working Capital	307.6	293.0	262.4	266.4	268.1	269.6
Total Rate Base	1,861.0	1,819.5	1,846.8	1,978.6	2,138.3	2,269.9

*In this schedule, the $2M of Miscellaneous Intangible Plant is not included in the 2006 historical actual, to be consistent with this treatment in the approved 2006 EDR for comparison purposes. However, this amount is related to capital contribution and is included in the 2007-2010 rate base calculation.

**Due to rounding, Net Fixed Assets are not the same as in Exhibit D1.

Table 5 shows 2008 Service Revenue Requirement forecast of $524.7 million and total 2008 operating revenue forecast of $463.0 million, resulting in a revenue deficiency of $61.7 million. In 2007, the revenue deficiency is $3.8 million.

The increase in revenue deficiency of $57.9 million is primarily the result of the capital program to modernize the aging distribution plant as explained in Exhibit D1, Tab 8. As shown in Table 6, rate base is projected to increase by $131.8 million in 2008, comprising an increase of net fixed assets of $127.8 million and an increase in working capital of $4 million.

In 2008, OM&A is projected to increase by $24.4 million and is described in more detail in Exhibits F1 and F2. Depreciation and amortization will increase by $21.3 million due to the increase in net fixed assets as discussed in Exhibit D1. The cost of capital, comprising interest expense and return on equity, will increase by $9.8 million in 2008. The changes in cost of capital are discussed in Exhibit E1.

Total Operating Revenue in 2008 is forecast to decrease by $1.1 million. This drop is due to the decrease of $4.2 million in Other Revenue, offset by an increase of $3.1 million in

distribution revenue. The reduction in Other Revenue in 2008 is explained in Exhibit I1, Tab 1, Schedule 1. It is primarily attributable to the reduction in gains on sale of utility property and the reduction in Other Distribution Revenue, partially offset by increases in Specific Service Charges and Late Payment Charges.

THESL notes that the change in working capital methodology and calculation has reduced the rate base. Previously, THESL was allowed working capital based on 15 percent of the cost of power and controllable distribution costs. In accordance with the OEB directive issued as part of the Decisions With Reason (EB-2005-0421), THESL commissioned Navigant Consulting Inc. to conduct a lead lag study to support its working capital allowance calculations in the current rate application.

Navigant Consulting Inc., whose study examined the net cash working capital requirement using expense levels between August 2005 and September 2006 was $298 million or approximately 12.45 percent of OM&A expenses and the cost of power. The Navigant report has been filed in Exhibit D1, Tab 15, Schedule 1.

For comparison purposes, the 2006 actual working capital allowance was calculated as 15 percent of the cost of power and controllable costs. The Lead Lag Study results were applied to the 2007-2010 forecast expenses to arrive at the working capital expenses. In each of these years, THESL's requested working capital allowance is approximately $51 million less than the working capital that is calculated based on 15 percent of the cost of power and controllable costs as shown in Exhibit J1, Tab 1, Schedule 7.

REVENUE REQUIREMENT

REGULATORY ASSETS AND DEFERRAL ACCOUNTS

This evidence provides a summary of THESL's regulatory assets, retail settlement variance accounts and deferral accounts. The account balances are recovered through separate rate riders and not included in the revenue requirement.

THESL established these accounts in accordance with the methodologies and requirements provided by the OEB as set out in the Accounting Procedures Handbook ("APH") and as set out in directions issued by the OEB from time to time.

SUMMARY OF REGULATORY ASSET ACCOUNTS

Detailed account balances are shown in Exhibit J1, Tab 2, Schedule 8 and summarized as follows:

Table 1: Summary of Regulatory Asset Balances ($ Millions)

	December 2006	December 2007	April 2008
RSVA	(8.0)	(17.3)	(22.8)
RARA Recovery of Approved Amounts	37.5	10.7	1.5
New Accounts	(5.5)	(9.6)	(10.3)
Total Balance	**24.0**	**(16.1)**	**(31.5)**

The following categories of Regulatory Assets will be discussed separately:

- Retail Settlement Variance Accounts ("RSVA")
- Recovery of Approved Regulatory Assets ("RARA")
- New accounts

RSVA

In accordance with the OEB's direction, at market opening, THESL established RSVA accounts to track the difference in cost of power expenses charged by the IESO and the revenue THESL charges its customers at retail rates. As well, THESL has tracked the costs in preparation for market opening in a transition cost regulatory asset account.

THESL received the OEB's approval to recover 25% of its accumulated RSVA and transition costs incurred to December 31, 2002 as Phase 1 of the Regulatory Asset Recovery, commencing April 1, 2004.

In September 2004, THESL and four other distribution companies were selected to undergo a public hearing process in Phase 2 of the Regulatory Asset Recovery (RP-2004-0100). On December 9, 2004, THESL received the OEB's approval to recover the balance as at December 31, 2003 over a three-year period commencing April 1, 2005 and ending March 31, 2008.

As part of the 2006 EDR, THESL requested and received approval for recovery of the RSVA balance as at December 31, 2004 and the projected balance for the OEB Fee Deferral and the Pension Cost Deferral accounts as at April 30, 2006. These recoveries were added to the then existing rate riders and were spread over a 23-month period from May 1, 2006 to March 31, 2008 to coincide with the end of Regulatory Asset Recovery Phase 2.

THESL continues to track the difference in cost of power expenses charged by the IESO and the revenue THESL charges its customers at retail rates in the RSVA accounts. Thus, the balances of these accounts represent activities since January 1, 2005 and forecast to December 31, 2010 based on recent trends of monthly balances.

Table 2: Summary of RSVA Account Balances ($ Millions)

	December 2006	December 2007	April 2008
$RSVA_{LV\ Charges}$ (1550)	0.2	0.4	0.5
$RSVA_{WMS}$ (1580)	(13.7)	(21.0)	(23.6)
$RSVA_{One\text{-}Time\ Charges}$ (1582)	2.9	4.7	5.4
$RSVA_{Network}$ (1584)	0.4	(0.1)	(2.3)
$RSVA_{Connection}$ (1586)	(6.0)	(5.7)	(7.1)
$RSVA_{Power}$ (1588)	8.2	4.3	4.3
RSVA Total	**(8.0)**	**(17.3)**	**(22.8)**

RARA

In its Decision with Reasons issued December 9, 2004 with respect to Phase 2 of RP-2004-0100, the OEB provided directions to Distributors on the implementation of rate riders.

- "9.0.17 – The remaining ongoing accounts will contain monthly activities post Dec 31, 2003 and shall include interest after this date on these activities.
- 9.0.18 – RARA (1590) will be debited by the approved total recovery amounts. Monthly rate riders will be credited to RARA (1590). Interest shall continue to apply to this account.
- 9.0.19 – At end of three-year period, the residual value (positive or negative) balance in the RARA (1590) shall be disposed of to rate classes in proportion to the recovery share as established when rate riders were implemented."

THESL followed the OEB's guidelines for the Phase 2 recovery, and for the amounts that were approved as part of the 2006 EDR Application.

The current RARA balance represents the residual value and carrying charges on the approved amounts.

Table 3: Summary of Approved Regulatory Assets Account 1590 ($ Millions)

	December 2006	December 2007	April 2008
Regulatory Assets Recovery	(45.4)	(72.7)	(81.8)
Approved Amounts Phase II	78.7	78.9	79.0
Carrying Charges	4.2	4.5	4.4
Total Balance	**37.5**	**10.7**	**1.5**

New Accounts

Tax Variance

The OEB granted a variance account to track the changes in PILs resulting from legislation changes that affect the amount of PILs included in the approved rates. The 2006 rates included recovery of Large Corporation Tax ("LCT") and Capital Cost Allowance ("CCA"). The LCT was eliminated and the CCA rate was changed subsequent to the finalization of the 2006 rates. These two changes resulted in an excess of $2.5 million per year of LCT and an excess of $1.7 million per year of CCA being included in the 2006 rates. In the 2007 rate application, the OEB eliminated LCT recovery included in the rates effective May 1, 2007. However, the change in CCA has not been reflected in the 2007 rates.

As a result, a LCT variance of $2.5 million has been recorded for the period from May 1, 2007 to April 30, 2008. A total of $3.4 million of CCA variance would be recorded from May 1, 2006 to April 30, 2008. Carrying charges are calculated for both accounts under USoA 1562 as shown Exhibit J1,Tab 2, Schedule 8.

Pre-market Opening Line Loss Variance

Before market opening, OPG implemented a Wholesale Energy Surcharge from June 1, 2001 to April 30, 2002. The OEB directed LDCs to charge five-percent line losses and to

track the variance from their actual line losses. Based on THESL's actual line losses of 3.1%, THESL has determined a variance of $2.9 million in customers' favour. Carrying charges are calculated for this variance as shown in Exhibit J1, Tab 2, Schedule 8.

As the OEB has not provided specific directions to record this variance, THESL did not apply to clear these amounts in Phase 2 of RP-2004-0100. THESL proposes to clear this amount and carrying charges as part of the 2008 EDR Application.

The following is a summary of the new account balances.

Table 4: Summary of New Variance Account Balances ($ Millions)

	December 2006	December 2007	April 2008
Tax Variance 1562	(1.7)	(5.4)	(5.9)
Tax Variance 1562 (carrying charges)	(0.0)	(0.2)	(0.3)
Pre-market Opening Line Loss Variance	(2.9)	(2.9)	(2.9)
Pre-market Opening Line Loss Variance 1571 (carrying charges)	(0.9)	(1.1)	(1.1)
Total Balance	**(5.5)**	**(9.6)**	**(10.3)**

PLANNED DISPOSITION OF REGULATORY ASSETS

In the Minimum Filing Requirements, the OEB directed Distributors to provide balances and detailed methods of recovery of existing accounts proposed to be cleared as part of the main rate case.

THESL is requesting disposition of certain Regulatory Asset accounts as follows:

- $RSVA_{WMS}$ balances in this account fluctuate widely depending on market conditions and cannot be forecast with accuracy. As a result, THESL proposes to

clear the actual balance as at December 31, 2006. Carrying charges for this balance will be calculated to April 30, 2008.

- For RARA, the estimated balance up to Apr 30, 2008 will be cleared, as the monthly amounts are reasonably predictable. THESL notes that its Regulatory Asset Recovery is scheduled to end on March 31, 2008, one month ahead of the end of the rate year on April 30, 2008. Toronto also notes that at March 31, 2008, recovery is projected to exceed the approved amount by $0.8 million and the carrying charges for the approved amount are estimated to be $4.4 million. As a result, there will be a net balance of $3.6 million in THESL's favour.

  In view of the net debit balance and the early ending date for the rate rider, THESL has requested the OEB's approval in a separate letter, for an extension of the rate rider recovery period, from March 31, 2008 to April 30, 2008. This would avoid having rate changes in two consecutive months and it would reduce the net balance to $1.5 million.

- For Tax Variance, the balance up to April 30, 2008 will be cleared as the amounts can be forecast accurately.

- Pre-Market Opening Line Loss Variance, balance with carrying charges calculated up to April 30, 2008 will be cleared.

THESL's proposed disposition of regulatory assets is summarized in the following table:

Table 5: Summary of Proposed Disposition ($ Millions)

	Balance as at December 31, 2006	Carrying Charges for Jan 1, 2007 to April 30, 2008	Balance as at April 30, 2008 Including Carrying Charges
RSVAWMS (1580)	(13.7)	(0.9)	(14.6)
RARA (1590)			1.5
Tax Variance (1562)			(6.3)
Pre-market Opening Line Loss Variance (1571)			(4.0)
Total Amount Requested for Disposition			(23.3)

THESL proposes to clear the regulatory assets by means of a rate rider credit over a 12-month period from May 1, 2008 to April 30, 2009.

Consistent with the OEB's direction for Regulatory Asset Recovery Phase 2 (RP-2004-0100), THESL proposes continued use of the OEB-approved Regulatory Asset Recovery Account (1590) to record the approved amount and to track the revenue from the new rate rider. Carrying charges will apply to this account, on a monthly basis using a simple interest calculation, at the same rate as other deferral accounts. The residual amount will be trued up at the end of the recovery period.

THESL is not seeking clearance of the following accounts:

- The other RSVA accounts: One-time, Connection, Network and Low Voltage Charges, will not be cleared as the increasing debit balances from One-Time Charges and Low Voltage Charges are expected to offset the credit balances from Connection and Network Charges.

- $RSVA_{Power}$, will not be cleared. The balance is attributable mainly to Global Adjustment that may fluctuate widely depending on market conditions. Also, the OEB has established a quarterly review process for commodity-related variance accounts such as $RSVA_{Power}$.

- Smart Meters

  In the OEB's Decision with Reasons for the 2006 EDR (EB 2005-0421), the smart meters costs were removed from THESL's distribution revenue requirement. Effective May 1, 2006, THESL commenced recovering smart meter costs through a rate rider of $0.47 (per 30 days) per residential customer and $1.04 (per 30 days) per general service customer. The OEB further directed LDCs to track the recovery, capital costs, operating costs and depreciation expenses in a number of variance accounts as regulatory assets.

  Effective May 1, 2007, THESL changed the smart meter rate to $0.68 for all customers for the 12-month ending April 30, 2008 pursuant to the OEB's Decision and Order for EB-2007-0582.

  In the current EDR application, THESL proposes to transfer the smart meter regulatory asset balances to net fixed assets. The associated costs will be included in the revenue requirement and recovered through the distribution tariff. As a result, the smart meter rate rider will be removed from the fixed customer charge, effective May 1, 2008.

REGULATORY ASSET RECOVERY BY CUSTOMER GROUPS

Consistent with the methodology accepted by the OEB in RP-2004-0100, Toronto Hydro proposes to allocate the Regulatory Assets to the customer classes based on the following principles:

- If costs are incurred based on energy consumption, Regulatory Assets will be allocated based on energy consumption
- If costs are incurred for the benefit of all customers irrespective of their energy consumption, Regulatory assets will be allocated based on number of customers
- If costs have been incurred in the past from customers using distribution revenues, Regulatory Asset will be allocated based on distribution revenue.

RSVA ***WMS***

As WMS are charged based on energy consumption, the amount recorded in the variance accounts will be allocated to customers based on class kWh.

Regulatory Assets Recovery Account

THESL proposes to recover this amount in proportion to the amount of rate riders recovered from various customer classes from April 1, 2005 to April 30, 2008.

Tax Variance

Since PILs was recovered from both the fixed and variable components of the distribution rates, the variance amount will be allocated to the customer classes based on distribution revenue.

Pre-Market Opening Line Loss Variance

THESL had determined the Line Loss Variance by class of customers, taking into account the lower distribution loss factor of the Large Use (>5000 kW) customers. The calculated line loss variance and carrying charges will be assigned to customers classes directly.

The various allocation percentages are provided as follows:

Table 6: Allocation Percentages

Rate Class	kWh	Distribution Revenue	Cumulative Rate Riders	Line Loss Variance
Residential	21.3%	38.5%	52.9%	18.1%
Gen Service <50 kW	10.0%	13.6%	12.7%	8.8%
Gen Service 50-1000 kW	38.2%	30.4%	24.4%	33.9%
Gen Service 1000-5000 kW	19.7%	12.1%	6.3%	17.5%
Large Use	10.1%	4.7%	3.2%	21.2%
Street Lighting	0.4%	0.4%	0.2%	0.4%
Unmetered Scattered Load	0.2%	0.3%	0.3%	0.2%

Development of Rate Riders

THESL proposes a single rate rider per rate class, set on a volumetric basis, consistent with the OEB's Decision with Reasons for RP-2004-0100. The development of the rate riders is shown in Exhibit J1, Tab 2, Schedule 10 and summarized in the following Table 7.

Table 7: Rate Riders

Rate Class	Allocated Regulatory Assets Dispostion Amounts ($)	$ Rate Rider
Residential	(5,440,088)	$(0.0010)/kWh
Gen Service <50 kW	(2,469,420)	$(0.0010)/kWh
Gen Service 50-1000 kW	(8,463,486)	$(0.32)/kVA
Gen Service 1000-5000 kW	(4,240,723)	$(0.36)/kVA
Large Use	(2,560,975)	$(0.47)/kVA
Street Lighting	(97,963)	$(0.30)/kVA
Unmetered Scattered Load	(52,355)	$(0.0009)/kWh

The impact of the rate riders are shown separately and combined with the distribution rate changes in Exhibit O1, Tab 1, Schedules 2 and 3, respectively.

Account Balance after Disposition

THESL proposes to follow the OEB's decision on Regulatory Assets Recovery Phase 2 (RP-2004-0100) as described in the previous section on the implementation of rate riders.

- The remaining ongoing accounts will contain monthly activities post disposition and will include interest after this date on these activities.
- The Regulatory Asset Recovery Account (1590) will be credited by the approved total disposition amounts. Monthly rate riders will be debited to RARA (1590). Interest shall continue to apply to this account.

Detailed account balances with the proposed disposition are shown in Exhibit J1, Tab 2, Schedule 9 and summarized in the following Table 8.

Table 8: Projected Regulatory Asset Balances at December 31 after Proposed Disposition ($ Millions)

	2008 Test	2009 Test	2010 Test
$RSVA_{WMS}$ (1580)	(14.1)	(21.9)	(30.0)
$RSVA_{Power}$ (1588)	4.5	4.7	4.9
Other RSVA (1582,1584,1586,1550)	(0.6)	0.5	1.4
RARA Recovery of Approved Amounts (1590)	(8.3)	(0.6)	(0.6)
New Accounts	0	0	0
Projected Balance	**(18.5)**	**(17.3)**	**(24.4)**

THESL notes the OEB has established a procedure to review the regulatory asset accounts periodically. If the $RSVA_{WMS}$ credit balance increases as projected over 2008-

2010 due to moderate electricity demand, THESL may apply for disposition of this account balance or some other account balances during these reviews.

Variance Accounts Requested

THESL requests a variance account to track the difference between annual OEB Cost Assessment and intervenors' cost awards and the forecast amount that is included in THESL's revenue requirement. The account will also record the costs of any OEB-mandated studies over the 2008-2010 period. This account will be similar in nature to the variance account the OEB granted on December 20, 2004 to track the difference in OEB cost assessment included in the 1999 rates and the actual OEB cost assessments in 2004 and subsequent years.

Distribution Expenses ($ Millions)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1		**Approved 2006 EDR**	**2006 Historical**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
2	Operating, Maintenance & Administration	153.8	161.3	164.3	188.5	198.7	205.8
3	Depreciation and Amortization	126.9	124.6	132.4	153.7	160.9	174.4
4	Municipal and Property Taxes	7.9	8.2	7.3	7.6	7.8	8.0
5	**Distribution Expenses before PILS**	**288.6**	**294.0**	**304.0**	**349.7**	**367.3**	**388.2**

Summary of Cost of Capital

Table 1: Year Ending December 31, 2006

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	**Particulars**	**Utility Capital Structure ($ Millions)**	**Deemed Structure (A)**	**Cost Rate (B)**	**Requested Return on Rate Base ($ Millions)**
2		**(A)**			**(A) * (B)**
3	Long Term Debt	1,182.7	65.0%	5.18%	61.3
4	Unfunded Short Term Debt				
5	Total Debt	1,182.7	65.0%	5.18%	61.3
6					
7	Preferred Shares				
8	Common Equity	636.8	35.0%	9.00%	57.3
9	Total Equity	636.8	35.0%	9.00%	57.3
10	Total Rate Base*	1,819.5	100.0%	6.52%	118.6

*In this schedule, the $2M of Miscellaneous Intangible Plant is not included in the 2006 historical actual, to be consistent with this treatment in the approved 2006 EDR for comparison purposes. However, this amount is related to capital contribution and is included in the 2007-2010 rate base calculation.

Table 2: Year Ending December 31, 2007

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	**Particulars**	**Utility Capital Structure ($ Millions)**	**Deemed Structure (A)**	**Cost Rate (B)**	**Requested Return on Rate Base ($ Millions)**
2		**(A)**			**(A) * (B)**
3	Long Term Debt	1,200.4	65.0%	5.51%	66.1
4	Unfunded Short Term Debt				
5	Total Debt	1,200.4	65.0%	5.51%	66.1
6					
7	Preferred Shares				
8	Common Equity	646.4	35.0%	9.00%	58.2
9	Total Equity	646.4	35.0%	9.00%	58.2
10	Total Rate Base**	1,846.8	100.0%	6.73%	124.3

**Due to rounding, Net Fixed Assets are not the same as in Exhibit D1.

Summary of Cost of Capital

Table 3: Year Ending December 31, 2008

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	**Particulars**	**Utility Capital Structure ($ Millions)**	**Deemed Structure (A)**	**Cost Rate**	**Requested Return on Rate Base ($ Millions)**
2		**(A)**		**(B)**	**(A) * (B)**
3	Long Term Debt	1,157.5	58.5%	5.57%	64.5
4	Unfunded Short Term Debt	79.1	4.0%	5.17%	4.1
5	Total Debt	1,236.6	62.5%	5.55%	68.6
6					
7	Preferred Shares				
8	Common Equity	742.0	37.5%	8.83%	65.5
9	Total Equity	742.0	37.5%	8.83%	65.5
10	Total Rate Base	1,978.6	100.0%	6.78%	134.1

Table 4: Year Ending December 31, 2009

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	**Particulars**	**Utility Capital Structure ($ Millions)**	**Deemed Structure (A)**	**Cost Rate**	**Requested Return on Rate Base ($ Millions)**
2		**(A)**		**(B)**	**(A) * (B)**
3	Long Term Debt	1,197.4	56.0%	5.59%	67.0
4	Unfunded Short Term Debt	85.5	4.0%	5.24%	4.5
5	Total Debt	1,283.0	60.0%	5.57%	71.5
6					
7	Preferred Shares				
8	Common Equity	855.3	40.0%	9.06%	77.5
9	Total Equity	855.3	40.0%	9.06%	77.5
10	Total Rate Base	2,138.3	100.0%	6.96%	148.9

Table 5: Year Ending December 31, 2010

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1	**Particulars**	**Utility Capital Structure ($ Millions)**	**Deemed Structure (A)**	**Cost Rate**	**Requested Return on Rate Base ($ Millions)**
2		**(A)**		**(B)**	**(A) * (B)**
3	Long Term Debt	1,271.1	56.0%	5.67%	72.1
4	Unfunded Short Term Debt	90.8	4.0%	5.28%	4.8
5	Total Debt	1,361.9	60.0%	5.64%	76.9
6					
7	Preferred Shares				
8	Common Equity	908.0	40.0%	9.19%	83.5
9	Total Equity	908.0	40.0%	9.19%	83.5
10	Total Rate Base	2,269.9	100.0%	7.06%	160.3

Calculation of Service Revenue Requirement ($ Millions)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1		**Approved 2006 EDR**	**2006 Historical**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
2	Operating, maintenance & Administration	153.8	161.3	164.3	188.5	198.7	205.8
3	Depreciation and amortization	126.9	124.6	132.4	153.7	160.9	174.4
4	Municipal and Property Taxes	7.9	8.2	7.3	7.6	7.8	8.0
5	PILS	46.7	46.0	39.5	40.9	39.5	38.1
6	**Cost of Service (excluding return)**	**335.4**	**340.0**	**343.6**	**390.6**	**406.8**	**426.3**
7	**Interest Charges**	62.7	$61.3	66.1	68.6	71.5	76.9
8	Return on Equity	58.6	$57.3	58.2	65.5	77.5	83.5
9	**Return on Rate Base (cost of Capital)**	**121.3**	**118.6**	**124.3**	**134.1**	**148.9**	**160.3**
10	**Service Revenue Requirement**	**456.6**	**458.6**	**467.9**	**524.7**	**555.7**	**586.7**
11	**Other Revenue Offset**	24.5	30.9	30.5	26.3	21.7	24.3
12	**Base Revenue Requirement**	**432.1**	**427.7**	**437.4**	**498.4**	**534.0**	**562.4**

Calculation of Revenue Deficiency

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**	**Source of Data**
2	Rate Base** ($ Million)	1,846.8	1,978.6	2,138.3	2,269.9	Exhibit D1,Tab 4, Schedule 1
3	Net Utility Income ($ Million)	121.9	93.7	129.2	146.9	Exhibit J1,Tab 2, Schedule 5
4	Indicated Rate of Return	6.6%	4.7%	6.0%	6.5%	Line (3) / Line (2)
5	Requested Return on Rate Base/Utility Cost of Capital	6.7%	6.8%	7.0%	7.1%	Exhibit J1, Tab 2, Schedule 2
6	Sufficiency (Deficiency) in rate of return	-0.13%	-2.04%	-0.92%	-0.59%	Line (4) - Line (5)
7	Revenue at existing rates and Other Revenue ($ Million)	464.1	463.0	525.9	566.5	Exhibit J1, Tab 2, Schedule 5
8	Service Revenue Requirement ($ Million)	467.9	524.7	555.7	586.7	Exhibit J1, Tab 2, Schedule 3
9	**Net Revenue Sufficiency (Deficiency) ($ Million)**	**-2.4**	**-40.4**	**-19.7**	**-13.5**	Line (6) * Line (2)
10	**Gross Revenue Sufficiency (Deficiency) ($ Million)**	**-3.8**	**-61.7**	**-29.8**	**-20.1**	Line (7) - Line (8)

**Due to rounding, Net Fixed Assets are not the same as in Exhibit D1.

Net Utility Income at Current Rates ($ Millions)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**Income Components**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**	
2	Distribution Revenue at Current Rates (Note 1)	433.6	436.7	504.2	542.2	
3	Other Revenue	30.5	26.3	21.7	24.3	
4	**Total Operating Revenue**	**464.1**	**463.0**	**525.9**	**566.5**	line (1)+(2)
5	Operation, Maintenance & Administration	164.3	188.5	198.7	205.8	
6	Depreciation and Amortization	132.4	153.7	160.9	174.4	
7	Municipal and Property Taxes	7.3	7.6	7.8	8.0	
8	Capital Taxes	5.8	5.6	4.8	3.4	
9	**Distribution Expenses (excluding interest expense)**	**309.8**	**355.3**	**372.1**	**391.6**	line (4)+(5)+(6)+(7)
10	**Utility Income Excluding Interest and Before Income Taxes**	**154.3**	**107.6**	**153.8**	**174.9**	line (3) - (8)
11	Income Tax Expense	32.4	14.0	24.6	28.1	
12	**Net Utility Income Excluding Interest**	**121.9**	**93.7**	**129.2**	**146.9**	

Note 1: Distribution Revenue at current rates is defined as follows:
2007 Bridge Year: Using the 2007 load forecast and the approved May 1, 2007 rates for 12 months
2008 Test Year: At the approved May 1, 2007 rates and 2008 load forecast
2009 Test Year: At the proposed May 1, 2008 rates and 2009 load forecast
2010 Test Year: At the proposed May 1, 2009 rates and 2010 load forecast

Summary of Components of Gross Revenue Deficiency

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1		**Approved 2006 EDR**	**2006 Historical***	**2007 Bridge****	**2008 Test****	**2009 Test****	**2010 Test****	**Notes:**
2	Net Fixed assets ($M)	1,553.4	1,526.5	1,584.4	1,712.2	1,870.2	2,000.3	Exhibit D1, Tab 4, Schedule 1
3	Working capital ($M)	307.6	293.0	262.4	266.4	268.1	269.6	Exhibit D1, Tab 4, Schedule 1
4	Rate Base ($M)	1,861.0	1,819.5	1,846.8	1,978.6	2,138.3	2,269.9	Exhibit D1, Tab 4, Schedule 1
5	Debt %	65.0%	65.0%	65.0%	62.5%	60.0%	60.0%	Exhibit J1, Tab 2, Schedule 2
6	Deemed Debt ($M)	1,209.6	1,182.7	1,200.4	1,236.6	1,283.0	1,361.9	line (4) * line (5)
7	Equity %	35.0%	35.0%	35.0%	37.5%	40.0%	40.0%	Exhibit J1, Tab 2, Schedule 2
8	Deemed Equity ($M)	651.3	636.8	646.4	742.0	855.3	908.0	line (4) * line (6)
9	Interest Rate	5.18%	5.18%	5.51%	5.55%	5.57%	5.64%	Exhibit J1, Tab 2, Schedule 2
10	Rate of Return	9.00%	9.00%	9.00%	8.83%	9.06%	9.19%	Exhibit J1, Tab 2, Schedule 2
11	Weighted Average Cost of Capital	6.52%	6.52%	6.73%	6.78%	6.96%	7.06%	Exhibit J1, Tab 2, Schedule 2
12	Interest Expense ($M)	62.7	61.3	66.1	68.6	71.5	76.9	line (9) * line (6)
13	Return on Equity ($M)	58.6	57.3	58.2	65.5	77.5	83.5	line (10) * line (8)
14	**Cost of Capital (Return on Rate Base)**	**121.3**	**118.6**	**124.3**	**134.1**	**148.9**	**160.3**	line (12) + line (13)
15	OM&A including Municipal and Property Taxes ($M)	161.7	169.4	171.6	196.0	206.5	213.8	Exhibit J1, Tab 2, Schedule 3
16	Depreciation and Amortization ($M)	126.9	124.6	132.4	153.7	160.9	174.4	Exhibit J1, Tab 2, Schedule 3
17	Interest Expense ($M)	62.7	61.3	66.1	68.6	71.5	76.9	Exhibit J1, Tab 2, Schedule 3
18	Return on Equity ($M)	58.6	57.3	58.2	65.5	77.5	83.5	Exhibit J1, Tab 2, Schedule 3
19	PILS ($M)	46.7	46.0	39.5	40.9	39.5	38.1	Exhibit J1, Tab 2, Schedule 3
20	**Service Revenue Requirement ($M)**	**456.6**	**458.6**	**467.9**	**524.7**	**555.7**	**586.7**	Sum of line (15) to (19)
21	Distribution Revenue at existing rates ($M)	432.1	425.5	433.6	436.7	504.2	542.2	Exhibit J1, Tab 2, Schedule 5
22	Other Revenues ($M)	24.5	30.9	30.5	26.3	21.7	24.3	Exhibit J1, Tab 2, Schedule 5
23	**Total Operating Revenue ($M)**	**456.6**	**456.3**	**464.1**	**463.0**	**525.9**	**566.5**	line (21) + line (22)
24	**Gross Revenue Sufficieny (Deficiency) $M**	**0.0**	**-2.2**	**-3.8**	**-61.7**	**-29.8**	**-20.1**	**line (23) - line (20)**

*In this schedule, the $2M of Miscellaneous Intangible Plant is not included in the 2006 historical actual, to be consistent with this treatment in the approved 2006 EDR for comparison purposes. However, this amount is related to capital contribution and is included in the 2007-2010 rate base calculation.

**Due to rounding, Net Fixed Assets are not the same as in Exhibit D1.

Calculation of Working Capital

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2007 Expenses ($ Millions)**	**Working Capital Factor**		**Expenses * Working Capital Factor ($ Millions)**	**15% Cost of Power and Controllable Expenses ($ Millions)**
2	Cost of Power	1,918.5	10.6%		203.9	
3	OM&A	171.6	14.1%		24.2	
4	Interest on Long Term Debt	64.4	7.7%		5.0	
5	Income and Capital Taxes	27.4	9.2%		2.5	
6	DRC	180.0	10.5%		18.8	
7	Sub-Total Working Requirement				254.5	
8	GST at 6%		Net Lag Days	Expenses * Net Lag Days/365 * 6% GST		
9	Revenue	2,371.7	-18.5	-7.2		
10	Cost of power	1,918.5	43.6	13.7		
11	OM&A Expenses	171.6	46.9	1.3		
12	GST Working Capital Requirement				7.9	
13	**2007 Total Working Capital**				**262.4**	**313.5**

Table 2

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2008 Expenses ($ Millions)**	**Working Capital Factor**		**Expenses * Working Capital Factor ($ Millions)**	**15% Cost of Power and Controllable Expenses ($ Millions)**
2	Cost of Power	1,922.6	10.6%		204.4	
3	OM&A	196.0	14.1%		27.7	
4	Interest on Long Term Debt	64.3	7.7%		5.0	
5	Income and Capital Taxes	28.7	9.2%		2.6	
6	DRC	180.4	10.5%		18.9	
7	Sub-Total Working Requirement				258.5	
8	GST at 6%		Net Lag Days	Expenses * Net Lag Days/365 * 6% GST		
9	Revenue	2,448.6	-18.5	-7.4		
10	Cost of power	1,922.6	43.6	13.8		
11	OM&A Expenses	196.0	46.9	1.5		
12	GST Working Capital Requirement				7.8	
13	**2008 Total Working Capital**				**266.4**	**317.8**

Table 3

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2009 Expenses ($ Millions)**	**Working Capital Factor**		**Expenses * Working Capital Factor ($ Millions)**	**15% Cost of Power and Controllable Expenses ($ Millions)**
2	Cost of Power	1,923.7	10.6%		204.5	
3	OM&A	206.5	14.1%		29.2	
4	Interest on Long Term Debt	67.0	7.7%		5.2	
5	Income and Capital Taxes	27.7	9.2%		2.5	
6	DRC	180.4	10.5%		18.9	
7	Sub-Total Working Requirement				260.2	
8	GST at 6%		Net Lag Days	Expenses * Net Lag Days/365 * 6% GST		
9	Revenue	2,486.6	-18.5	-7.6		
10	Cost of power	1,923.7	43.6	13.8		
11	OM&A Expenses	206.5	46.9	1.6		
12	GST Working Capital Requirement				7.8	
13	**2009 Total Working Capital**				**268.1**	**319.5**

Table 4

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2010 Expenses ($ Millions)**	**Working Capital Factor**		**Expenses * Working Capital Factor ($ Millions)**	**15% Cost of Power and Controllable Expenses ($ Millions)**
2	Cost of Power	1,925.6	10.6%		204.7	
3	OM&A	213.8	14.1%		30.2	
4	Interest on Long Term Debt	71.8	7.7%		5.6	
5	Income and Capital Taxes	26.6	9.2%		2.4	
6	DRC	180.5	10.5%		18.9	
7	Sub-Total Working Requirement	2,418.4			261.8	
8	GST at 6%		Net Lag Days	Expenses * Net Lag Days/365 * 6% GST		
9	Revenue	2,511.9	-18.5	-7.6		
10	Cost of power	1,925.6	43.6	13.8		
11	OM&A Expenses	213.8	46.9	1.6		
12	GST Working Capital Requirement				7.8	
13	**2010 Total Working Capital**				**269.6**	**320.9**

December 2006-April 2008 Regulatory Asset Account Balances ($)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		**Account**	**December 2006**	**December 2007**	**April 2008**
2	1550_Low Voltage Variance Acct	1550	151,124	404,616	489,760
3	1550_Low Voltage Variance Acct (Interest)	1550	1,679	13,907	20,587
4		**1550 Total**	**152,803**	**418,524**	**510,346**
5	1562_Deferred Payments in Lieu of Taxes	1562	(1,679,588)	(5,370,861)	(5,941,157)
6	1562_Deferred Payments in Lieu of Taxes (Interest)	1562	(22,407)	(233,578)	(319,024)
7		**1562 Total**	**(1,701,995)**	**(5,604,439)**	**(6,260,181)**
8	1571_Pre-market Opening Energy Variance	1571	(2,880,375)	(2,880,375)	(2,880,375)
9	1571_Pre-market Opening Energy Variance (Interest)	1571	(948,603)	(1,080,813)	(1,124,882)
10		**1571 Total**	**(3,828,978)**	**(3,961,188)**	**(4,005,257)**
11	1580_RSVA_WMS	1580	(14,551,983)	(21,011,165)	(23,359,959)
12	1580_RSVA_WMS (Interest)	1580	851,895	60,427	(274,520)
13		**1580 Total**	**(13,700,088)**	**(20,950,738)**	**(23,634,478)**
14	1582_RSVA_ONE-TIME	1582	2,636,238	4,294,349	4,897,298
15	1582_RSVA_ONE-TIME (Interest)	1582	281,766	434,481	503,644
16		**1582 Total**	**2,918,004**	**4,728,830**	**5,400,942**
17	1584_RSVA_Network	1584	559,054	55,365	(2,177,594)
18	1584_RSVA_Network (Interest)	1584	(158,534)	(125,447)	(136,786)
19		**1584 Total**	**400,520**	**(70,082)**	**(2,314,380)**
20	1586_RSVA_Connection	1586	(5,018,038)	(4,521,352)	(5,881,171)
21	1586_RSVA_Connection (Interest)	1586	(935,595)	(1,138,965)	(1,215,771)
22		**1586 Total**	**(5,953,634)**	**(5,660,317)**	**(7,096,942)**
23	1588_RSVA_POWER	1588	8,739,658	4,571,476	4,571,476
24	1588_RSVA_POWER (Interest)	1588	(547,101)	(321,327)	(251,383)
25		**1588 Total**	**8,192,557**	**4,250,149**	**4,320,092**
26	1590_Recovery of Regulatory Asset Balances	1590	(45,444,450)	(72,728,838)	(81,835,403)
27	1590_RARA Approved Amount	1590	78,730,202	78,943,538	79,001,933
28	1590_RARA Approved Amount Carrying Charges	1590	4,224,083	4,533,903	4,364,567
29		**1590 Total**	**37,509,835**	**10,748,603**	**1,531,097**
30					
31	**Subtotals**				
32	**RSVA (1550,1582,1584,1586) excl.WMS, Power**		**(2,482,307)**	**(583,046)**	**(3,500,034)**
33	**RSVA-WMS (1580)**		**(13,700,088)**	**(20,950,738)**	**(23,634,478)**
34	**RSVA-Power (1588)**		**8,192,557**	**4,250,149**	**4,320,092**
35	**RARA (1590)**		**37,509,835**	**10,748,603**	**1,531,097**
36	**Tax Variance (1562)**		**(1,701,995)**	**(5,604,439)**	**(6,260,181)**
37	**Pre Market Opening Variance (1571)**		**(3,828,978)**	**(3,961,188)**	**(4,005,257)**
38	**Total**		**23,989,024**	**(16,100,659)**	**(31,548,761)**

2008-2010 Regulatory Asset Account Balances($)
(After Proposed Disposition)

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		**Account**	**2008**	**2009**	**2010**
2	1550_Low Voltage Variance Acct	1550	660,046	915,476	1,170,906
3	1550_Low Voltage Variance Acct (Interest)	1550	37,853	73,523	120,917
4		**1550 Total**	**697,899**	**988,999**	**1,291,822**
5	1562_Deferred Payments in Lieu of Taxes	1562	-	-	-
6	1562_Deferred Payments in Lieu of Taxes (Interest)	1562	-	-	-
7		**1562 Total**	**-**	**-**	**-**
8	1571_Pre-market Opening Energy Variance	1571	-	-	-
9	1571_Pre-market Opening Energy Variance (Interest)	1571	-	-	-
10		**1571 Total**	**-**	**-**	**-**
11	1580_RSVA_WMS	1580	(13,505,563)	(20,551,943)	(27,598,324)
12	1580_RSVA_WMS (Interest)	1580	(568,247)	(1,336,390)	(2,427,963)
13		**1580 Total**	**(14,073,809)**	**(21,888,333)**	**(30,026,286)**
14	1582_RSVAONE-TIME	1582	6,103,197	7,912,046	9,720,895
15	1582_RSVAONE-TIME (Interest)	1582	669,645	987,836	1,389,052
16		**1582 Total**	**6,772,843**	**8,899,882**	**11,109,947**
17	1584_RSVA_NW	1584	(1,518,069)	(2,523,227)	(3,715,843)
18	1584_RSVA_NW (Interest)	1584	(158,776)	(242,489)	(376,589)
19		**1584 Total**	**(1,676,846)**	**(2,765,717)**	**(4,092,432)**
20	1586_RSVA_CN	1586	(4,993,158)	(4,995,016)	(5,137,188)
21	1586_RSVA_CN (Interest)	1586	(1,359,926)	(1,584,832)	(1,813,009)
22		**1586 Total**	**(6,353,084)**	**(6,579,848)**	**(6,950,197)**
23	1588_RSVAPOWER	1588	4,571,476	4,571,476	4,571,476
24	1588_RSVAPOWER (Interest)	1588	(111,496)	98,335	308,165
25		**1588 Total**	**4,459,980**	**4,669,810**	**4,879,641**
26	1590_Recovery of Regulatory Asset Balances	1590	15,550,007	-	-
27	1590_RARA Approved Amount	1590	(23,284,522)	101,220	121,464
28	1590_RARA Approved Amount Carrying Charges	1590	(593,216)	(719,546)	(714,165)
29		**1590 Total**	**(8,327,731)**	**(618,326)**	**(592,701)**
30					
31	**Subtotals**				
32	**RSVA (1550,1582,1584,1586) excl.WMS, Power**		**(559,188)**	**543,316**	**1,359,141**
33	**RSVA-WMS (1580)**		**(14,073,809)**	**(21,888,333)**	**(30,026,286)**
34	**RSVA-Power (1588)**		**4,459,980**	**4,669,810**	**4,879,641**
35	**RARA (1590)**		**(8,327,731)**	**(618,326)**	**(592,701)**
36	**Tax Variance (1562)**		**-**	**-**	**-**
37	**Pre Market Opening Variance (1571)**		**-**	**-**	**-**
38	**Total**		**(18,500,749)**	**(17,293,534)**	**(24,380,205)**
39					

Rate Rider Development

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
1	**Allocators**			**Residential**	**GS < 50 kW**	**GS 50-1000kW (Interval and Non Interval Metered)**	**GS 1000-5000kW**	**Large Users**	**Unmetered Scattered Load**	**Street Lighting**	**Total**
2	2008 Forecast kVA			N/A	N/A	25,938,545	11,740,732	5,428,878	N/A	317,526	**43,425,682**
3	2008 Forecast kWh (Not Adjusted for Losses)			5,498,828,031	2,575,446,564	9,850,462,000	5,086,725,921	2,589,940,302	57,950,907	110,184,165	**25,769,537,891**
4	Line Loss Variance by Class ($)		**2001**	313,794	159,968	598,009	303,447	370,107	3,599	5,491	**1,754,416**
5			**2002**	206,324	94,590	378,383	199,832	239,328	2,128	5,374	**1,125,960**
6			**Total**	**520,118**	**254,558**	**976,392**	**503,279**	**609,435**	**5,728**	**10,865**	**2,880,375**
7	RARA $ (from April 1, 2005 to April 30, 2008)			55,783,800	13,395,441	25,732,627	6,678,452	3,419,722	301,415	201,516	**105,512,973**
8	2007 Distribution Revenue $ (excluding Transformer Allowance)			171,800,840	60,654,439	135,222,933	53,850,884	21,098,145	1,136,447	1,664,665	**445,428,353**
9											
10	**Allocation Percentages**										
11	Energy Consumed - kWhs	kWh		21.3%	10.0%	38.2%	19.7%	10.1%	0.2%	0.4%	**100.0%**
12	Line Loss Variance by Class	LLV		18.1%	8.8%	33.9%	17.5%	21.2%	0.2%	0.4%	**100.0%**
13	Cumulative Regulatory Asset Recovery by Class	RARA		52.9%	12.7%	24.4%	6.3%	3.2%	0.3%	0.2%	**100.0%**
14	Distribution Revenue	Distrbution Revenue		38.5%	13.6%	30.4%	12.1%	4.7%	0.3%	0.4%	**100.0%**

Table 2

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
1	**Regulatory Asset Accounts**	**Proposed Disposition Amounts ($)**	**Allocator**	**Residential**	**GS < 50 kW**	**GS 50-1000kW (Interval and Non Interval Metered)**	**GS 1000-5000kW**	**Large Users**	**Unmetered Scattered Load**	**Street Lighting**	**Total**
2	RSVA_WMS (1580) Dec 31, 2006 balance with Carrying Charges calculated to April 30, 2008	(14,590,669)	kWh	(3,113,427)	(1,458,214)	(5,577,315)	(2,880,096)	(1,466,420)	(32,812)	(62,386)	(14,590,669)
3	Regulatory Asset Recovery of Approved Amount RARA (1590) April 30, 2008 balance with Carrying Charges calculated to April 30, 2008	1,531,097	RARA	809,478	194,381	373,406	96,911	49,624	4,374	2,924	1,531,097
4	Pre-Market Opening Line Loss Variance with Carrying Charges (April 30, 2008)	(4,005,257)	LLV	(723,241)	(353,972)	(1,357,705)	(699,826)	(847,440)	(7,965)	(15,108)	(4,005,257)
5	Tax Variance (1562) with Carrying Charges (April 30, 2008)	(6,260,181)	Distribution Revenue	(2,412,898)	(851,616)	(1,901,871)	(757,712)	(296,739)	(15,952)	(23,393)	(6,260,181)
6	**Total**	**(23,325,010)**		(5,440,088)	(2,469,420)	(8,463,486)	(4,240,723)	(2,560,975)	(52,355)	(97,963)	**(23,325,010)**

Table 3

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1		**Residential**	**GS < 50 kW**	**GS 50-1000kW (Interval and Non Interval Metered)**	**GS 1000-5000kW**	**Large Users**	**Unmetered Scattered Load**	**Street Lighting**
2		**kWh**	**kWh**	**kVA**	**kVA**	**kVA**	**kWh**	**kVA**
3	**Incremental Rate Riders**	$ (0.0010)	$ (0.0010)	$ (0.32)	$ (0.36)	$ (0.47)	$ (0.0009)	$ (0.30)

LOADS, CUSTOMERS AND REVENUE

The purpose of this evidence is to present the Company's load, customer and distribution revenue forecast for the test years. The detailed test year forecasts are shown in Exhibit K1, Tab 7, Schedules 1-5. The bridge year forecasts are in Exhibit K1, Tab 6, Schedules 1-7, and the historical loads, customers and revenues are shown in Exhibit K1, Tab 1, Schedules 1-4 and Tab 5, Schedules 1-5.

Table 1 below provides a summary of the loads, revenue, and customer forecasts. The revenue forecast is calculated based on proposed distribution rates, excluding commodity, and excluding rate riders.

Table 1: Total Load, Revenues and Customers

Year	Total GWh	Total kVA	Total Distribution Revenue	Total Customers
2006(A)	26,437	42,897,735	425,479,276	855,688
2007	26,629	43,480,578	433,639,162	861,529
2008	26,688	43,425,682	498,333,086	886,287
2009	26,685	43,229,017	533,655,409	916,290
2010	26,707	42,920,729	562,282,591	956,841

Notes:

1. Streetlights and Unmetered loads measured as connections
2. Total kVA are billed kVA (eg: not including residential or GS<50 classes) net of CDM savings.
3. Total Customers are as of year-end and streetlight and unmetered loads measured as connections.

On a rate class basis, forecast sales and revenues are shown in Table 2 below.

Table 2: Sales and Revenue by Rate Class

Year	Residential	GS<50	GS 50-1000kW Non-Interval Metered	GS 50-1000kW Interval Metered	GS 1000-5000kW	Large Users	Unmetered Load	Street lighting
Load (GWh)								
2006(A)	5,352	2,471	6,143	3,660	5,145	2,592	58	106
2007	5,427	2,571	3,884	6,015	5,070	2,578	58	110
2008	5,499	2,575	1,365	8,486	5,087	2,590	58	110
2009	5,613	2,574	662	9,060	5,093	2,596	58	110
2010	5,786	2,575	153	9,404	5,100	2,601	58	111
Distribution Revenue ($000s)								
2006(A)	169,445	58,556	87,500	41,046	48,236	17,892	1,143	1,661
2007	171,887	60,665	54,847	77,192	48,361	17,886	1,136	1,665
2008	206,635	69,859	21,166	121,736	52,888	20,325	1,625	4,101
2009	229,809	73,549	10,611	136,142	54,964	21,492	1,874	5,214
2010	252,470	77,020	2,455	143,887	55,750	22,201	2,103	6,396

Table 3 shows historical and forecast annual use per customer.

Table 3: Annual Use Per Customer

Year	Residential	GS<50	GS 50-1000kW Non-Interval Metered	GS 50-1000kW Interval Metered	GS 1000-5000kW	Large Users	Unmetered Load	Street lighting
Load (kWh per connection)								
2004(A)	9,177	38,150	672,860	2,264,227	10,109,919	55,182,300	4,029	681
2005(A)	9,629	39,448	684,004	2,249,366	10,171,293	54,534,032	3,967	684
2006(A)	8,958	36,885	633,745	2,147,957	9,874,854	54,005,801	2,946	661
2007	9,037	38,383	628,908	1,126,423	9,734,987	52,619,498	3,255	686
2008	8,910	38,478	639,023	897,836	9,629,926	52,855,925	3,270	689
2009	8,708	38,481	621,753	859,639	9,508,055	52,981,396	3,279	691
2010	8,510	38,533	575,747	830,904	9,391,244	53,086,705	3,285	692
Annual Growth %								
2005(A)	4.9%	3.4%	1.7%	-0.7%	0.6%	-1.2%	-1.6%	0.3%
2006(A)	-7.0%	-6.5%	-7.3%	-4.5%	-2.9%	-1.0%	-25.7%	-3.3%
2007	0.9%	4.1%	-0.8%	-47.6%	-1.4%	-2.6%	10.5%	3.8%
2008	-1.4%	0.2%	1.6%	-20.3%	-1.1%	0.4%	0.5%	0.5%
2009	-2.3%	0.0%	-2.7%	-4.3%	-1.3%	0.2%	0.3%	0.2%
2010	-2.3%	0.1%	-7.4%	-3.3%	-1.2%	0.2%	0.2%	0.2%

Note: Use per customer based on mid-year customer

LOAD FORECAST METHODOLOGY

The Company's revenue and load forecast is developed in a three-step process. First, a total system purchased energy forecast is developed based on multifactor regression techniques that incorporate historical load, weather, and economic data. Second, a system demand forecast is developed based on historical and forecast load factor relationships. Finally, energy and demand by rate class are forecast based on historical billing statistics. A forecast of customers by rate class is also determined using time-series econometric methodologies. Revenues are determined by applying the proposed distribution rates to the rate class billing determinants for the forecast period.

KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth), load characteristics (peak hours per month) and calendar variables (days in month, seasonal). The regression model uses monthly kWh and monthly values of independent variables from 1998 through to the latest actual values (June 2006) to determine the monthly regression coefficients.

Data for Toronto Hydro's total system load is available only as far back as January 1998. With the amalgamation of the six former municipal utilities in 1998, consistent data is available only for this time period. The monthly model therefore has over 100 data points, which is a reasonable data set for use in a multiple regression analysis.

Historically, load growth for Toronto Hydro has been fairly stable (on a normalized basis), averaging 0.6 percent annually over the 1999-2005 period. Figure 1 and Table 4 below show historical loads.

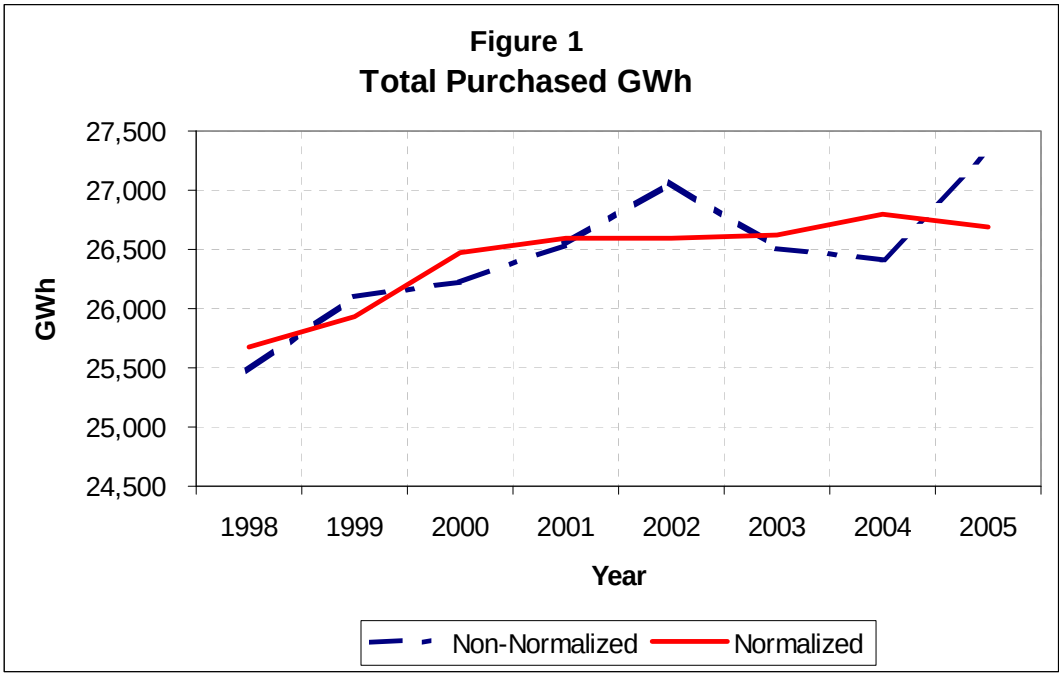


Table 4: Historical Annual Load

Year	Non-Normalized GWh	Growth GWh	Percent Change (%)	Normalized GWh	Growth GWh	Percent Change (%)
1998	25,478			25,682		
1999	26,105	627	2.5	25,932	250	1.0
2000	26,228	124	0.5	26,472	539	2.1
2001	26,543	314	1.2	26,588	116	0.4
2002	27,070	527	2.0	26,595	7	0.0
2003	26,517	(553)	(2.0)	26,619	24	0.1
2004	26,417	(100)	(0.4)	26,794	175	0.7
2005	27,312	895	3.4	26,693	(101)	(0.4)
Annual Average			1.0			0.6

The main drivers of load growth over time are economic conditions, while the primary driver of year-over-year changes is weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses both growth in the Company's customer base as well as general economic conditions within the Company's operating area – is captured in the model using an index of economic output, Real Gross Domestic Product ("GDP").

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days ("HDD" – a measure of coldness in winter) and Cooling Degree Days ("CDD" – measure of summer heat) are modelled.

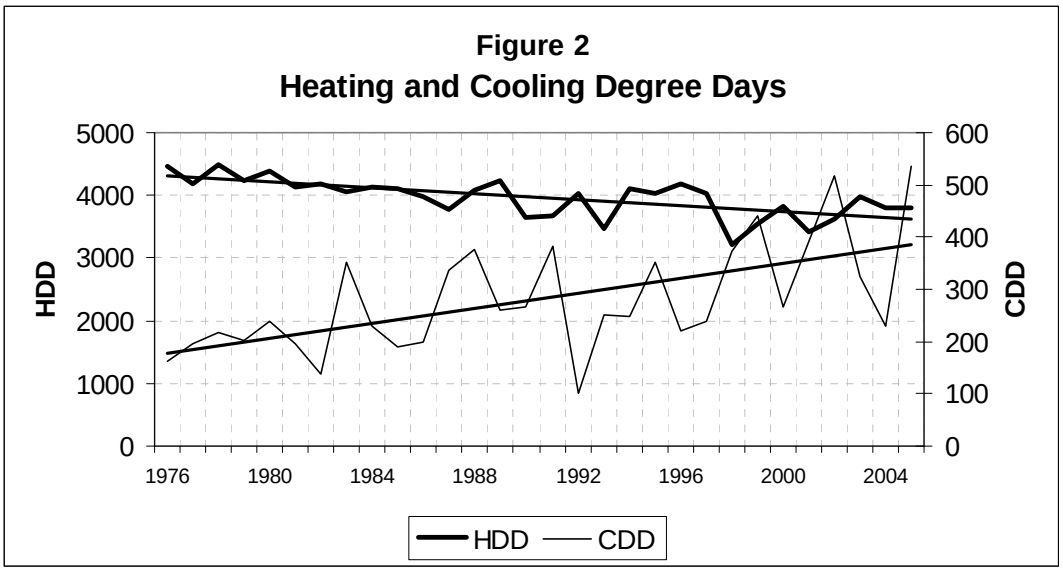
The third main factor determining energy use in the monthly model can be classified as "calendar factors". For example, the number of days in a particular month will impact energy use. The modelling of purchased energy uses number of days in the month, hours of peak load in a month, and two dummy[1] variables – one to capture the typically lower usage in the spring and fall months, and the other to capture the impact of the 2003 August blackout on energy use in that month.

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Based on *a priori* assumptions about which input variables will impact energy use, different models were fit. Using stepwise regression techniques different explanatory variables were tested with the ultimate model being determined both by model statistics and by forecast accuracy.

[1] A dummy variable is a way of capturing a one-time, or recurring, impact in a time series model. It takes on the value of either 0 or 1.

Appendix A contains the historical and forecast load and input variable details. Also shown is the in-sample model forecast of load. The results of the model testing are shown in Appendix B.

From the regression model, the forecast of energy usage is determined by applying the model coefficients to forecasts of the input variables. The forecast for heating and cooling degree-day inputs is based on a ten-year historical average of HDD and CDD. A ten-year average was chosen over the 30-year average based on analysis of the annual HDD and CDD data that shows a definite trend (see Figure 2 below). The forecast of Ontario GDP is based on forecasts of 2007 GDP growth from the six Canadian chartered banks for 2007, and extended over the test years using time-series forecasting methodology. The forecasts of the calendar variables are based on the 2008-2010 calendars.



The forecast determined by the regression model is evaluated on a monthly basis against historical monthly load to determine any outlier months. For those months where the

model predicts load which is beyond historical maximum and minimum bands, a manual adjustment to the model forecast may be applied based on professional judgement. In the case of the current forecast, an adjustment was applied to a number of points throughout the forecast (see Appendix C for details).

In total, the manual adjustments adjust the forecast downwards in each of 2008-2010 by less than 0.8 percent of total load, and in the Company's view improve the forecast.

The preceding describes the process to develop the kWh load forecast that is used to determine revenues. The company has also provided, in Appendix D, sensitivity analysis around the base load forecast. This analysis provides the impacts on the total load for both a one-percent and a five-percent variance in the degree-day, and a one-percent and a two-percent variance in economic growth parameters of the model.

Peak Demand Forecast

The forecast of peak demand by customer class, which is used to determine revenue for those customers billed on a demand basis, is established using historical relationships between energy and demand.

Appendix E shows the historical and forecast load factors and peak demand forecast.

CDM impact on kWh and kW Forecast

The load forecast as described above does not explicitly take into account any load impacts arising from CDM programs undertaken by the Company. Savings derived from the planned CDM programs are developed based on the programs, program designs, anticipated take-up and free-rider estimates. Details on THESL's CDM programs are contained in Exhibit G1, Tab 1, Schedules 1-3.

CDM savings, by rate class, are shown in Table 5 below. The demand (and revenue) forecast shown in Table 1 above is net of these savings.

Table 5: CDM Savings by Customer Class

Year	Residential	GS<50	GS 50-1000kW Non-Interval Metered	GS 50-1000kW Interval Metered	GS 1000-5000kW	Large Users	Unmetered Load	Street lighting
Energy Savings (kWh)								
2007	113,934,294	38,748,806	0	44,479,206	49,339,876	16,836,000	2,727,864	0
2008	144,735,041	46,748,806	0	63,145,873	55,591,874	16,836,000	2,727,864	0
2009	175,535,788	54,748,806	0	81,812,540	61,843,872	16,836,000	2,727,864	0
2010	190,936,162	58,748,806	0	91,145,873	64,969,871	16,836,000	2,727,864	0
Demand Savings (kVA)								
2007	0	0	0	13,364	16,734	8,372	0	0
2008	0	0	0	18,608	17,010	8,372	0	0
2009	0	0	0	23,852	17,286	8,372	0	0
2010	0	0	0	26,474	17,424	8,372	0	0

Customer Forecast

The forecast of customer numbers by rate class is shown in Table 6.

Table 6: Total Customers

Year	Residential	GS<50	GS 50-1000kW Non-Interval Metered	GS 50-1000kW Interval Metered	GS 1000-5000kW	Large Users	Unmetered Load	Street lighting	Total (w/o street lighting)	Total
Customers										
1999	578,029	69,815	9,282	124	490	41	9,347	158,614	667,128	825,742
2000	578,460	67,879	9,934	177	465	46	13,357	159,021	670,318	829,339
2001	582,669	67,296	10,166	284	483	47	12,781	159,785	673,726	833,511
2002	586,714	67,274	9,641	886	482	46	13,766	159,821	678,809	838,630
2003	590,109	67,064	9,484	1,424	497	47	13,094	159,821	681,719	841,540
2004	594,976	66,505	9,621	1,525	498	47	14,450	159,821	687,622	847,443
2005	597,469	67,147	9,871	1,627	517	47	13,408	159,861	690,086	849,947
2006	599,080	67,017	9,680	1,764	516	49	17,721	159,861	695,827	855,688
2007	604,842	66,961	2,671	8,900	525	49	17,721	159,861	701,668	861,529
2008	629,617	66,906	1,600	10,001	532	49	17,721	159,861	726,426	886,287
2009	659,663	66,850	530	11,076	539	49	17,721	159,861	756,429	916,290
2010	700,310	66,795	0	11,558	547	49	17,721	159,861	796,980	956,841
Annual Increase										
2000	431	-1,936	652	53	-25	5	4,010	407	3,190	3,597
2001	4,209	-583	232	107	18	1	-576	764	3,408	4,172
2002	4,045	-22	-525	602	-1	-1	985	36	5,083	5,119
2003	3,395	-210	-157	538	15	1	-672	0	2,910	2,910
2004	4,867	-559	137	101	1	0	1,355	0	5,902	5,902
2005	2,493	642	250	102	19	0	-1,042	40	2,464	2,504
2006	1,611	-130	-191	137	-1	2	4,314	0	5,742	5,742
2007	5,762	-56	-7,009	7,136	9	0	0	0	5,841	5,841
2008	24,775	-56	-1,070	1,101	7	0	0	0	24,758	24,758
2009	30,047	-55	-1,070	1,075	7	0	0	0	30,003	30,003
2010	40,647	-55	-530	482	7	0	0	0	40,551	40,551

Note: Customers numbers as of year-end

Customer additions in the company's operating area have been fairly flat over recent history, with about 3,500 to 4,500 new customers (excluding Unmetered loads and streetlighting) added annually.

On top of natural customer growth forecast based on historical trends, over the forecast period however, the mix of customers is expected to be altered significantly as a result of the Smart Meter program, and specifically the Government of Ontario's "Installation of Smart Meters and Smart Sub-Metering Systems in Condominiums" legislation which calls for individually-metered multi-residential units.

The forecast of customers for the residential sector in 2008 through 2010 anticipates that new residential condominium buildings in Toronto will incorporate individually-metered units, and thus where previously the load associated with these customers would have been billed as a single General Service customer, it will now be billed as individual residential units.

Additionally, it is anticipated that most existing multi-unit buildings will also be converted to individual meters by the end of 2010, and the associated load will convert from being bulk-metered to individually-metered.

Appendix A - Load Forecast Input Data

Table 1

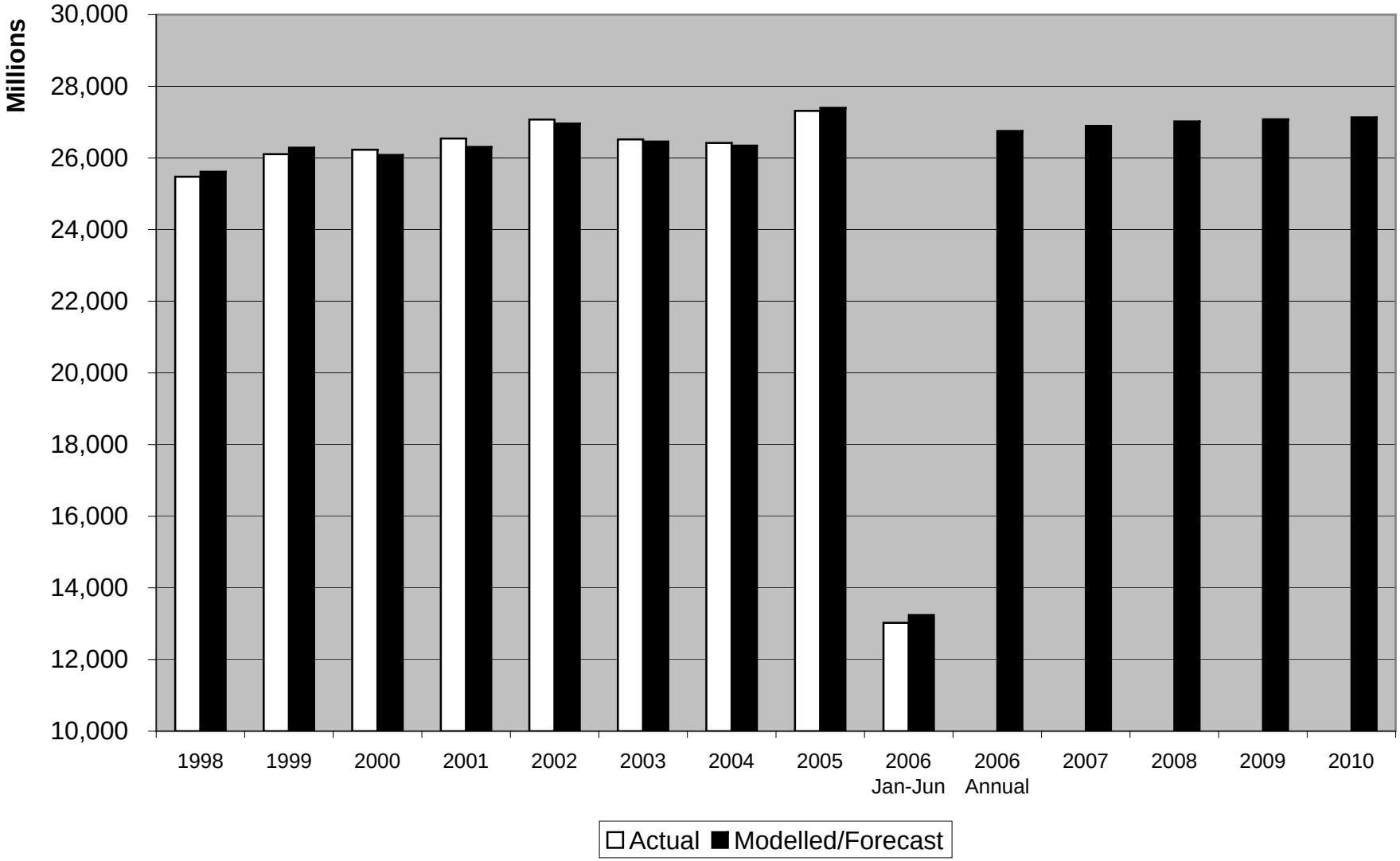
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
1	**Date**	**Total kWhs Purchased**	**Peak Hrs.%**	**Ontario Real GDP Monthly Index**	**Actual HDD**	**Actual CDD**	**Square of days in the month**	**Blackout dummy**	**Spring fall dummy**	**Modelled / Forecast Total kWhs Purchased**	**Modelled Variance From Actual (kWhs)**	**Modelled Variance From Actual (%)**
2	January-98	2,268,691,908	45.2	101.0	624.8	0.0	961	0	0	2,261,201,406	- 7,490,502	-0.3%
3	February-98	2,005,397,353	47.6	102.1	512.2	0.0	784	0	0	2,041,416,490	36,019,138	1.8%
4	March-98	2,177,707,945	47.3	103.1	492.3	0.0	961	0	1	2,163,279,419	- 14,428,526	-0.7%
5	April-98	1,915,449,783	46.7	103.6	282.0	0.0	900	0	1	1,990,938,633	75,488,851	3.9%
6	May-98	2,030,073,727	43.0	104.1	59.1	28.6	961	0	1	2,011,254,081	- 18,819,646	-0.9%
7	June-98	2,162,083,337	48.9	104.6	54.7	82.4	900	0	0	2,198,303,579	36,220,242	1.7%
8	July-98	2,311,481,591	47.3	105.2	1.0	101.3	961	0	0	2,286,199,005	- 25,282,586	-1.1%
9	August-98	2,326,048,060	43.0	105.8	3.4	117.7	961	0	0	2,321,222,034	- 4,826,026	-0.2%
10	September-98	2,057,677,788	46.7	106.5	39.7	45.0	900	0	1	2,018,357,746	- 39,320,042	-1.9%
11	October-98	1,987,588,350	45.2	107.4	223.4	0.0	961	0	1	2,024,335,225	36,746,875	1.8%
12	November-98	2,056,010,399	46.7	108.4	392.6	0.0	900	0	1	2,062,202,915	6,192,517	0.3%
13	December-98	2,179,353,405	45.2	109.4	535.1	0.0	961	0	0	2,237,848,499	58,495,094	2.7%
14	January-99	2,372,811,722	43.0	110.0	749.8	0.0	961	0	0	2,341,257,358	- 31,554,364	-1.3%
15	February-99	2,056,885,200	47.6	110.7	548.1	0.0	784	0	0	2,084,442,527	27,557,327	1.3%
16	March-99	2,223,685,098	49.5	111.4	550.6	0.0	961	0	1	2,227,502,141	3,817,043	0.2%
17	April-99	1,951,365,928	46.7	112.2	296.7	0.0	900	0	1	2,022,734,364	71,368,436	3.7%
18	May-99	2,011,698,402	43.0	113.0	97.1	19.4	961	0	1	2,026,342,501	14,644,099	0.7%
19	June-99	2,258,793,232	48.9	113.8	25.0	96.0	900	0	0	2,252,928,994	- 5,864,238	-0.3%
20	July-99	2,523,396,363	45.2	114.3	0.0	196.5	961	0	0	2,609,351,175	85,954,813	3.4%
21	August-99	2,231,897,414	45.2	114.7	8.4	79.1	961	0	0	2,234,318,440	2,421,026	0.1%
22	September-99	2,109,327,199	46.7	115.2	49.3	48.9	900	0	1	2,060,585,726	- 48,741,473	-2.3%
23	October-99	2,026,187,683	43.0	115.9	267.6	0.0	961	0	1	2,060,534,360	34,346,677	1.7%
24	November-99	2,083,566,014	48.9	116.5	367.5	0.0	900	0	1	2,082,870,932	- 695,082	0.0%
25	December-99	2,255,262,264	45.2	117.2	579.3	0.0	961	0	0	2,282,880,344	27,618,080	1.2%
26	January-00	2,386,897,446	43.0	117.5	738.9	0.0	961	0	0	2,356,647,325	- 30,250,121	-1.3%
27	February-00	2,192,459,227	48.3	117.9	612.7	0.0	841	0	0	2,198,324,710	5,865,483	0.3%
28	March-00	2,173,158,290	49.5	118.2	418.6	0.0	961	0	1	2,177,889,943	4,731,653	0.2%
29	April-00	2,006,840,160	42.2	118.4	339.2	0.0	900	0	1	2,040,524,062	33,683,902	1.7%
30	May-00	2,070,945,216	47.3	118.5	139.6	23.7	961	0	1	2,099,292,883	28,347,667	1.4%
31	June-00	2,132,970,174	48.9	118.7	34.5	41.1	900	0	0	2,093,584,617	- 39,385,557	-1.8%
32	July-00	2,241,291,564	43.0	119.1	6.6	71.8	961	0	0	2,211,489,962	- 29,801,602	-1.3%
33	August-00	2,329,925,940	47.3	119.6	11.5	92.5	961	0	0	2,303,598,168	- 26,327,772	-1.1%
34	September-00	2,101,631,395	44.4	120.0	99.5	35.2	900	0	1	2,044,986,592	- 56,644,803	-2.7%
35	October-00	2,062,413,545	45.2	120.0	212.7	1.2	961	0	1	2,057,943,861	- 4,469,684	-0.2%
36	November-00	2,140,651,832	48.9	119.9	432.0	0.0	900	0	1	2,126,204,057	- 14,447,775	-0.7%
37	December-00	2,389,284,009	40.9	119.9	780.3	0.0	961	0	0	2,374,355,126	- 14,928,883	-0.6%
38	January-01	2,395,116,958	47.3	120.0	684.9	0.0	961	0	0	2,356,531,908	- 38,585,050	-1.6%
39	February-01	2,145,131,243	47.6	120.0	587.6	0.0	784	0	0	2,131,428,120	- 13,703,123	-0.6%
40	March-01	2,292,615,174	47.3	120.1	566.6	0.0	961	0	1	2,249,970,531	- 42,644,643	-1.9%
41	April-01	2,014,050,963	44.4	120.5	293.8	1.4	900	0	1	2,038,344,051	24,293,088	1.2%
42	May-01	2,072,660,160	47.3	120.9	111.5	12.2	961	0	1	2,054,055,819	- 18,604,341	-0.9%
43	June-01	2,253,766,123	46.7	121.3	29.8	79.7	900	0	0	2,212,778,635	- 40,987,488	-1.8%
44	July-01	2,318,039,691	45.2	121.2	9.3	100.9	961	0	0	2,323,605,550	5,565,859	0.2%
45	August-01	2,521,769,178	47.3	121.0	0.0	160.0	961	0	0	2,520,539,321	- 1,229,857	0.0%
46	September-01	2,098,233,758	42.2	120.8	73.6	35.7	900	0	1	2,024,497,251	- 73,736,507	-3.5%
47	October-01	2,118,056,429	47.3	121.3	232.5	2.0	961	0	1	2,085,092,349	- 32,964,080	-1.6%
48	November-01	2,102,465,501	48.9	121.7	325.8	0.0	900	0	1	2,075,593,381	- 26,872,120	-1.3%
49	December-01	2,210,982,297	40.9	122.1	505.0	0.0	961	0	0	2,236,664,247	25,681,950	1.2%
50	January-02	2,321,169,174	47.3	122.6	572.2	0.0	961	0	0	2,305,160,146	- 16,009,028	-0.7%
51	February-02	2,115,253,676	47.6	123.2	540.2	0.0	784	0	0	2,115,554,838	301,162	0.0%
52	March-02	2,258,433,031	43.0	123.8	545.6	0.0	961	0	1	2,228,090,973	- 30,342,058	-1.3%
53	April-02	2,099,524,906	48.9	124.0	329.5	8.3	900	0	1	2,111,001,503	11,476,597	0.5%
54	May-02	2,086,745,039	47.3	124.2	227.5	7.8	961	0	1	2,109,569,297	22,824,258	1.1%
55	June-02	2,207,938,708	44.4	124.4	36.2	70.0	900	0	0	2,182,350,466	- 25,588,242	-1.2%
56	July-02	2,632,596,360	47.3	124.9	0.0	192.4	961	0	0	2,636,552,553	3,956,193	0.2%
57	August-02	2,504,648,078	45.2	125.4	0.2	142.7	961	0	0	2,466,299,903	- 38,348,175	-1.5%
58	September-02	2,262,892,800	44.4	125.9	21.8	87.6	900	0	1	2,190,909,861	- 71,982,939	-3.2%
59	October-02	2,128,860,347	47.3	126.1	292.2	10.0	961	0	1	2,155,779,686	26,919,339	1.3%

1	Date	Total kWhs Purchased	Peak Hrs.%	Ontario Real GDP Monthly Index	Actual HDD	Actual CDD	Square of days in the month	Blackout dummy	Spring fall dummy	Modelled / Forecast Total kWhs Purchased	Modelled Variance From Actual (kWhs)	Modelled Variance From Actual (%)
60	November-02	2,146,043,266	46.7	126.2	445.0	0.0	900	0	1	2,139,805,986	- 6,237,280	-0.3%
61	December-02	2,306,274,923	43.0	126.4	619.4	0.0	961	0	0	2,319,245,771	12,970,848	0.6%
62	January-03	2,477,590,442	47.3	126.8	814.5	0.0	961	0	0	2,443,422,507	- 34,167,935	-1.4%
63	February-03	2,238,134,200	47.6	127.2	699.0	0.0	784	0	0	2,209,657,442	- 28,476,758	-1.3%
64	March-03	2,289,846,372	45.2	127.5	581.1	0.0	961	0	1	2,267,834,317	- 22,012,055	-1.0%
65	April-03	2,096,327,191	46.7	127.4	372.5	2.4	900	0	1	2,112,925,265	16,598,074	0.8%
66	May-03	2,037,892,596	45.2	127.2	177.9	0.0	961	0	1	2,056,251,588	18,358,992	0.9%
67	June-03	2,148,356,368	46.7	127.0	43.4	52.9	900	0	0	2,149,029,573	673,205	0.0%
68	July-03	2,389,669,035	47.3	126.7	0.2	118.3	961	0	0	2,401,428,695	11,759,660	0.5%
69	August-03	2,277,084,342	43.0	126.4	2.0	128.0	961	1	0	2,277,084,342	0	0.0%
70	September-03	2,078,542,054	46.7	126.0	54.9	24.0	900	0	1	2,013,249,903	- 65,292,151	-3.1%
71	October-03	2,096,949,754	47.3	126.4	276.0	0.0	961	0	1	2,115,943,546	18,993,792	0.9%
72	November-03	2,117,989,786	44.4	126.9	398.5	0.0	900	0	1	2,106,334,804	- 11,654,982	-0.6%
73	December-03	2,268,669,978	45.2	127.3	561.5	0.0	961	0	0	2,302,081,071	33,411,093	1.5%
74	January-04	2,501,998,529	45.2	127.4	849.1	0.0	961	0	0	2,452,677,300	- 49,321,229	-2.0%
75	February-04	2,234,108,612	46.0	127.5	631.7	0.0	841	0	0	2,224,156,905	- 9,951,707	-0.4%
76	March-04	2,264,115,079	49.5	127.7	487.3	0.0	961	0	1	2,240,374,214	- 23,740,865	-1.0%
77	April-04	2,045,083,540	46.7	128.3	331.5	0.0	900	0	1	2,086,350,064	41,266,524	2.0%
78	May-04	2,053,760,778	43.0	128.9	158.9	8.6	961	0	1	2,068,529,853	14,769,075	0.7%
79	June-04	2,107,802,970	48.9	129.6	44.2	31.6	900	0	0	2,098,528,898	- 9,274,072	-0.4%
80	July-04	2,283,266,058	45.2	130.2	3.6	86.4	961	0	0	2,299,147,154	15,881,096	0.7%
81	August-04	2,239,009,124	45.2	130.9	12.8	59.6	961	0	0	2,218,879,585	- 20,129,539	-0.9%
82	September-04	2,158,953,092	46.7	131.5	30.0	41.2	900	0	1	2,071,582,489	- 87,370,603	-4.0%
83	October-04	2,073,135,931	43.0	131.9	226.3	1.5	961	0	1	2,088,898,479	15,762,548	0.8%
84	November-04	2,109,067,029	48.9	132.2	379.1	0.0	900	0	1	2,133,022,273	23,955,244	1.1%
85	December-04	2,346,844,116	45.2	132.5	643.4	0.0	961	0	0	2,359,465,746	12,621,630	0.5%
86	January-05	2,467,007,284	43.0	132.6	770.0	0.0	961	0	0	2,415,501,424	- 51,505,860	-2.1%
87	February-05	2,171,472,019	47.6	132.8	616.4	0.0	784	0	0	2,182,451,703	10,979,684	0.5%
88	March-05	2,316,441,471	47.3	133.0	608.6	0.0	961	0	1	2,308,163,005	- 8,278,466	-0.4%
89	April-05	2,036,335,963	46.7	133.2	306.8	0.0	900	0	1	2,087,292,726	50,956,763	2.5%
90	May-05	2,043,892,184	45.2	133.4	189.4	0.8	961	0	1	2,082,428,032	38,535,848	1.9%
91	June-05	2,438,660,873	48.9	133.7	8.9	146.3	900	0	0	2,463,515,738	24,854,865	1.0%
92	July-05	2,576,436,582	43.0	133.9	0.0	188.7	961	0	0	2,628,814,550	52,377,968	2.0%
93	August-05	2,467,424,363	47.3	134.2	0.2	140.7	961	0	0	2,495,209,041	27,784,678	1.1%
94	September-05	2,194,024,026	46.7	134.5	22.6	52.1	900	0	1	2,111,298,351	- 82,725,675	-3.8%
95	October-05	2,103,390,094	43.0	134.6	220.2	7.6	961	0	1	2,113,242,006	9,851,912	0.5%
96	November-05	2,141,349,894	48.9	134.7	388.4	0.0	900	0	1	2,145,141,762	3,791,868	0.2%
97	December-05	2,355,650,589	43.0	134.9	665.3	0.0	961	0	0	2,367,082,459	11,431,870	0.5%
98	January-06	2,319,644,565	45.2	135.2	551.8	0.0	961	0	0	2,319,185,404	- 459,161	0.0%
99	February-06	2,155,413,787	47.6	135.4	604.2	0.0	784	0	0	2,183,452,439	28,038,652	1.3%
100	March-06	2,265,251,223	49.5	135.7	516.6	0.0	961	0	1	2,278,375,516	13,124,293	0.6%
101	April-06	1,983,341,502	42.2	136.0	293.3	0.0	900	0	1	2,066,197,401	82,855,899	4.2%
102	May-06	2,097,027,705	47.3	136.3	136.9	26.0	961	0	1	2,155,351,664	58,323,959	2.8%
103	June-06	2,203,262,536	48.9	136.6	19.5	72.6	900	0	0	2,238,269,796	35,007,260	1.6%
104	July-06		43.0	136.9	4.3	121.9	961	0	0	2,422,696,497		
105	August-06		47.3	137.2	5.8	105.4	961	0	0	2,392,050,775		
106	September-06		44.4	137.4	55.0	40.9	900	0	1	2,089,176,856		
107	October-06		45.2	137.7	249.1	2.5	961	0	1	2,128,236,405		
108	November-06		48.9	138.0	410.8	0.0	900	0	1	2,145,065,685		
109	December-06		40.9	138.3	604.7	0.0	961	0	0	2,334,521,075		
110	January-07		47.3	138.6	732.6	0.0	961	0	0	2,433,887,296		
111	February-07		47.6	138.9	603.1	0.0	784	0	0	2,192,494,732		
112	March-07		47.3	139.1	549.6	0.0	961	0	1	2,294,640,048		
113	April-07		44.4	139.4	332.7	1.2	900	0	1	2,099,231,062		
114	May-07		47.3	139.7	162.8	11.0	961	0	1	2,086,677,985		
115	June-07		46.7	140.0	31.8	71.2	900	0	0	2,238,579,429		
116	July-07		45.2	140.2	4.3	121.9	961	0	0	2,442,789,730		
117	August-07		47.3	140.5	5.8	105.4	961	0	0	2,401,520,853		
118	September-07		42.2	140.8	55.0	40.9	900	0	1	2,087,670,439		
119	October-07		47.3	141.1	249.1	2.5	961	0	1	2,128,246,800		
120	November-07		48.9	141.4	410.8	0.0	900	0	1	2,145,452,470		
121	December-07		40.9	141.6	604.7	0.0	961	0	0	2,343,879,790		

1	Date	Total kWhs Purchased	Peak Hrs.%	Ontario Real GDP Monthly Index	Actual HDD	Actual CDD	Square of days in the month	Blackout dummy	Spring fall dummy	Modelled / Forecast Total kWhs Purchased	Modelled Variance From Actual (kWhs)	Modelled Variance From Actual (%)
122	January-08		47.3	141.9	732.6	0.0	961	0	0	2,443,261,722		
123	February-08		48.3	142.2	603.1	0.0	841	0	0	2,237,802,191		
124	March-08		43.0	142.5	549.6	0.0	961	0	1	2,282,849,924		
125	April-08		48.9	142.7	332.7	1.2	900	0	1	2,098,541,209		
126	May-08		45.2	143.0	162.8	11.0	961	0	1	2,086,504,256		
127	June-08		46.7	143.3	31.8	71.2	900	0	0	2,248,009,436		
128	July-08		47.3	143.6	4.3	121.9	961	0	0	2,462,821,931		
129	August-08		43.0	143.9	5.8	105.4	961	0	0	2,389,770,930		
130	September-08		46.7	144.1	55.0	40.9	900	0	1	2,119,013,074		
131	October-08		47.3	144.4	249.1	2.5	961	0	1	2,128,693,524		
132	November-08		44.4	144.7	410.8	0.0	900	0	1	2,146,001,727		
133	December-08		45.2	145.0	604.7	0.0	961	0	0	2,374,516,941		
134	January-09		45.2	145.3	732.6	0.0	961	0	0	2,442,111,793		
135	February-09		47.6	145.5	603.1	0.0	784	0	0	2,211,329,106		
136	March-09		47.3	145.8	549.6	0.0	961	0	1	2,313,487,074		
137	April-09		46.7	146.1	332.7	1.2	900	0	1	2,099,038,091		
138	May-09		43.0	146.4	162.8	11.0	961	0	1	2,086,354,328		
139	June-09		48.9	146.7	31.8	71.2	900	0	0	2,268,404,083		
140	July-09		47.3	146.9	4.3	121.9	961	0	0	2,472,267,695		
141	August-09		43.0	147.2	5.8	105.4	961	0	0	2,399,216,695		
142	September-09		46.7	147.5	55.0	40.9	900	0	1	2,128,458,838		
143	October-09		45.2	147.8	249.1	2.5	961	0	1	2,128,543,595		
144	November-09		46.7	148.1	410.8	0.0	900	0	1	2,145,396,374		
145	December-09		45.2	148.3	604.7	0.0	961	0	0	2,383,962,705		
146	January-10		43.0	148.6	732.6	0.0	961	0	0	2,440,961,865		
147	February-10		47.6	148.9	603.1	0.0	784	0	0	2,220,774,870		
148	March-10		49.5	149.2	549.6	0.0	961	0	1	2,315,528,532		
149	April-10		46.7	149.5	332.7	1.2	900	0	1	2,099,483,855		
150	May-10		43.0	149.7	162.8	11.0	961	0	1	2,085,800,092		
151	June-10		48.9	150.0	31.8	71.2	900	0	0	2,277,849,848		
152	July-10		45.2	150.3	4.3	121.9	961	0	0	2,471,117,767		
153	August-10		45.2	150.6	5.8	105.4	961	0	0	2,419,258,152		
154	September-10		46.7	150.9	55.0	40.9	900	0	1	2,137,904,603		
155	October-10		43.0	151.1	249.1	2.5	961	0	1	2,128,393,666		
156	November-10		48.9	151.4	410.8	0.0	900	0	1	2,145,791,021		
157	December-10		45.2	151.7	604.7	0.0	961	0	0	2,389,408,470		
158	Annual											
159	1998	25,477,563,644	553	105	3,220	375	n/a	n/a	n/a	25,616,559,032	138,995,388	0.5%
160	1999	26,104,876,518	553	114	3,539	440	n/a	n/a	n/a	26,285,748,862	180,872,344	0.7%
161	2000	26,228,468,798	549	119	3,826	266	n/a	n/a	n/a	26,084,841,306	- 143,627,491	-0.5%
162	2001	26,542,887,475	552	121	3,420	392	n/a	n/a	n/a	26,309,101,163	- 233,786,312	-0.9%
163	2002	27,070,380,307	552	125	3,630	519	n/a	n/a	n/a	26,960,320,983	- 110,059,324	-0.4%
164	2003	26,517,052,119	552	127	3,982	326	n/a	n/a	n/a	26,455,243,053	- 61,809,066	-0.2%
165	2004	26,417,144,859	553	130	3,798	229	n/a	n/a	n/a	26,341,612,960	- 75,531,899	-0.3%
166	2005	27,312,085,342	551	134	3,797	536	n/a	n/a	n/a	27,400,140,797	88,055,455	0.3%
167	2006 Jan-Jun	13,023,941,317	281	136	2,122	99	n/a	n/a	n/a	13,240,832,220	216,890,903	1.7%
168	2006 Annual	n/a	550	137	3,452	369	n/a	n/a	n/a	26,752,579,513	n/a	n/a
169	2007	n/a	552	140	3,742	354	n/a	n/a	n/a	26,895,070,634	n/a	n/a
170	2008	n/a	553	143	3,742	354	n/a	n/a	n/a	27,017,786,865	n/a	n/a
171	2009	n/a	553	147	3,742	354	n/a	n/a	n/a	27,078,570,377	n/a	n/a
172	2010	n/a	553	150	3,742	354	n/a	n/a	n/a	27,132,272,741	n/a	n/a

Note: Forecast Volumes before CDM Adjustment

Figure 1: Actual & Modelled/Forecast kWhs



Appendix B - Load Forecast Model Evaluation Matrix

Table 1

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
	Model 1	**Model 2**	**Model 3**	**Model 4**	**Model 5**	**Model 6**	**Model 7**	**Model 8**	**Model 9**	**Model 10**	**Model 11**	**Model 12**
Independent Variables (t-stats)												
Constant value	1.74	-0.73	-0.12	-0.81	5.60	8.90	8.31	5.51	**3.45**	6.71	9.28	-2.10
No. of Customers	-1.27											
GDP Index	1.83	7.29	3.80	8.22	7.16	6.95	4.63	7.12	**7.16**	6.92	6.97	7.16
Energy Prices	0.42											
Peak Hours	3.73	2.50	0.97	2.11	2.76		3.53	2.75		0.88		
Peak Hours %									**2.73**			2.73
Days of Month		8.40	6.05	9.45								12.34
Days of Month Squared					11.23	11.73		10.94	**12.29**	10.77	11.57	
HDD	10.28	25.86	13.77	28.43	21.01	20.44	14.63	20.83	**20.98**	17.77	18.17	21.10
CDD	11.81	31.09		34.29	22.68	22.40	16.67	22.56	**22.67**	23.31	23.59	22.74
21C DD			18.54									
Summer Dummy	1.24											
Winter Dummy	-1.93											
Spring Dummy	-2.48											
Spring/Fall Dummy					-4.45	-3.94	-1.60	-4.40	**-4.42**			-4.48
Adjusted Spring/Fall Dummy										-3.57	-4.02	
Leap Year Dummy								0.07				
Blackout Dummy				-4.35	-3.59	-3.88	-1.85	-3.57	**-3.60**	-3.72	-3.91	-3.60
Model Statistics												
Adj R-squared	87.00	93.20	82.53	93.02	94.26	93.86	86.71	94.20	**94.25**	93.89	93.90	94.28
Durbin-Watson	2.51	1.65	1.62	1.42	1.91	2.12	2.48	1.92	**1.92**	1.64	1.70	1.90
F-Test	50.25	246.88	90.77	249.84	238.14	258.49	110.84	206.17	**237.69**	222.56	260.12	239.00
In Sample MAPE	1.64%	1.35%	2.33%	1.26%	1.25%	1.31%	1.96%	1.25%	**1.26%**	1.29%	1.30%	1.25%
Ex-Post RMSE	2.48%	1.78%	3.20%	2.01%	2.40%	2.50%	3.47%	2.41%	**2.41%**	2.44%	2.45%	2.40%
THEIL	0.28	0.22	0.35	0.20	0.20	0.21	0.30	0.20	**0.20**	0.20	0.21	0.20
Estimation Period	Jan 98 - Jun 06											

Appendix C - Adjustments to Model Forecast Loads

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**2007**	**1998-2005 Maximun**	**1998-2005 Minimum**	**2007 Regression**	**Manual Adjustment to 1998-2005 Maximum**	**2007 Load Forecast after Manual Adjustment**
2	Jan	2,501,998,529	2,268,691,908	2,433,887,296	0	2,433,887,296
3	Feb	2,238,134,200	2,005,397,353	2,192,494,732	0	2,192,494,732
4	Mar	2,316,441,471	2,173,158,290	2,294,640,048	0	2,294,640,048
5	Apr	2,099,524,906	1,915,449,783	2,111,231,062	-12,000,000	2,099,231,062
6	May	2,086,745,039	2,011,698,402	2,129,677,985	-43,000,000	2,086,677,985
7	Jun	2,438,660,873	2,107,802,970	2,238,579,429	0	2,238,579,429
8	Jul	2,632,596,360	2,241,291,564	2,442,789,730	0	2,442,789,730
9	Aug	2,521,769,178	2,231,897,414	2,401,520,853	0	2,401,520,853
10	Sep	2,262,892,800	2,057,677,788	2,087,670,439	0	2,087,670,439
11	Oct	2,128,860,347	1,987,588,350	2,151,246,800	-23,000,000	2,128,246,800
12	Nov	2,146,043,266	2,056,010,399	2,175,452,470	-30,000,000	2,145,452,470
13	Dec	2,389,284,009	2,179,353,405	2,343,879,790	0	2,343,879,790
14	Total	27,762,950,977	25,236,017,625	27,003,070,634	-108,000,000	26,895,070,634
		Adjustment%	-0.4%			

Table 2

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**2008**	**1998-2005 Maximun**	**1998-2005 Minimum**	**2007 Regression**	**Manual Adjustment to 1998-2005 Maximum**	**2008 Load Forecast after Manual Adjustment**
2	Jan	2,501,998,529	2,268,691,908	2,443,261,722	0	2,443,261,722
3	Feb	2,238,134,200	2,005,397,353	2,261,802,191	-24,000,000	2,237,802,191
4	Mar	2,316,441,471	2,173,158,290	2,282,849,924	0	2,282,849,924
5	Apr	2,099,524,906	1,915,449,783	2,142,541,209	-44,000,000	2,098,541,209
6	May	2,086,745,039	2,011,698,402	2,128,504,256	-42,000,000	2,086,504,256
7	Jun	2,438,660,873	2,107,802,970	2,248,009,436	0	2,248,009,436
8	Jul	2,632,596,360	2,241,291,564	2,462,821,931	0	2,462,821,931
9	Aug	2,521,769,178	2,231,897,414	2,389,770,930	0	2,389,770,930
10	Sep	2,262,892,800	2,057,677,788	2,119,013,074	0	2,119,013,074
11	Oct	2,128,860,347	1,987,588,350	2,160,693,524	-32,000,000	2,128,693,524
12	Nov	2,146,043,266	2,056,010,399	2,163,001,727	-17,000,000	2,146,001,727
13	Dec	2,389,284,009	2,179,353,405	2,374,516,941	0	2,374,516,941
14	Total	27,762,950,977	25,236,017,625	27,176,786,864	-159,000,000	27,017,786,864
		Adjustment%	-0.6%			

Table 3

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**2009**	**1998-2005 Maximun**	**1998-2005 Minimum**	**2007 Regression**	**Manual Adjustment to 1998-2005 Maximum**	**2009 Load Forecast after Manual Adjustment**
2	Jan	2,501,998,529	2,268,691,908	2,442,111,793	0	2,442,111,793
3	Feb	2,238,134,200	2,005,397,353	2,211,329,106	0	2,211,329,106
4	Mar	2,316,441,471	2,173,158,290	2,313,487,074	0	2,313,487,074
5	Apr	2,099,524,906	1,915,449,783	2,141,038,091	-42,000,000	2,099,038,091
6	May	2,086,745,039	2,011,698,402	2,127,354,328	-41,000,000	2,086,354,328
7	Jun	2,438,660,873	2,107,802,970	2,268,404,083	0	2,268,404,083
8	Jul	2,632,596,360	2,241,291,564	2,472,267,695	0	2,472,267,695
9	Aug	2,521,769,178	2,231,897,414	2,399,216,695	0	2,399,216,695
10	Sep	2,262,892,800	2,057,677,788	2,128,458,838	0	2,128,458,838
11	Oct	2,128,860,347	1,987,588,350	2,159,543,595	-31,000,000	2,128,543,595
12	Nov	2,146,043,266	2,056,010,399	2,183,396,374	-38,000,000	2,145,396,374
13	Dec	2,389,284,009	2,179,353,405	2,383,962,705	0	2,383,962,705
14	Total	27,762,950,977	25,236,017,625	27,230,570,378	-152,000,000	27,078,570,378
		Adjustment%	-0.6%			

Table 4

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1	**2010**	**1998-2005 Maximun**	**1998-2005 Minimum**	**2007 Regression**	**Manual Adjustment to 1998-2005 Maximum**	**2010 Load Forecast after Manual Adjustment**
2	Jan	2,501,998,529	2,268,691,908	2,440,961,865	0	2,440,961,865
3	Feb	2,238,134,200	2,005,397,353	2,220,774,870	0	2,220,774,870
4	Mar	2,316,441,471	2,173,158,290	2,333,528,532	-18,000,000	2,315,528,532
5	Apr	2,099,524,906	1,915,449,783	2,150,483,855	-51,000,000	2,099,483,855
6	May	2,086,745,039	2,011,698,402	2,136,800,092	-51,000,000	2,085,800,092
7	Jun	2,438,660,873	2,107,802,970	2,277,849,848	0	2,277,849,848
8	Jul	2,632,596,360	2,241,291,564	2,471,117,767	0	2,471,117,767
9	Aug	2,521,769,178	2,231,897,414	2,419,258,152	0	2,419,258,152
10	Sep	2,262,892,800	2,057,677,788	2,137,904,603	0	2,137,904,603
11	Oct	2,128,860,347	1,987,588,350	2,158,393,666	-30,000,000	2,128,393,666
12	Nov	2,146,043,266	2,056,010,399	2,203,791,021	-58,000,000	2,145,791,021
13	Dec	2,389,284,009	2,179,353,405	2,393,408,470	-4,000,000	2,389,408,470
14	Total	27,762,950,977	25,236,017,625	27,344,272,742	-212,000,000	27,132,272,742
		Adjustment %	-0.8%			

Notes:
Before CDM load reduction impact

Appendix D - Load Forecast Sensitivity Analysis

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4
1		**2008**	**2009**	**2010**
2	**Base Purchased GWh Forecast**	27,018	27,079	27,132
3				
4	**Degree Day Sensitivity**			
5	HDD			
6	+1%	27,027	27,092	27,141
7	-1%	27,007	27,065	27,124
8	+5%	27,068	27,122	27,169
9	-5%	26,965	27,011	27,083
10	CDD			
11	+1%	27,028	27,090	27,143
12	-1%	27,007	27,067	27,121
13	+5%	27,072	27,133	27,187
14	-5%	26,963	27,023	27,075
15				
16	**Economic Activity**			
17	+1%	27,060	27,148	27,223
18	-1%	26,973	26,997	27,036
19	+2%	27,106	27,210	27,304
20	-2%	26,930	26,965	26,928

Notes:
1. Economic Acitivity "+/- 1%" or "+/-2%" refers to the value of annual growth rate %
2. "Base purchase" is before CDM load reduction impact

Appendix E - Peak Demand Forecast

Table 1

	Col. 1	Col. 2	Col. 3
1		**System load factors**	**Annual total of monthly peak demand kW**
2	1998	74.5%	46,740,793
3	1999	75.2%	47,412,666
4	2000	74.4%	48,106,072
5	2001	74.7%	48,638,179
6	2002	73.4%	50,511,240
7	2003	74.5%	48,746,917
8	2004	74.8%	48,244,696
9	2005	75.4%	49,615,970
10	2006	73.5%	49,292,194
11	2007	74.0%	49,313,200
12	2008	73.8%	49,392,896
13	2009	73.6%	49,641,284
14	2010	73.6%	49,740,117

Notes:
2007-2010 Annual kW net of CDM load reduction impact

kWh, kW, Customer Growth, and Load Factors

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1	**Year**	**kWh Purchase**	**System Load Factors % WAG**	**kW - Network**	**kW - Line Connection**	**kW - Transformer Connection**	**Customer Count***	**Customer Growth YOY %**
2	2006 Historical	26,437,085,050	73.5%	49,292,194	48,378,238	49,671,411	855,453	1.4%
3	2007 Bridge	26,629,004,588	74.0%	49,313,200	48,431,774	49,951,630	858,663	0.4%
4	2008 Test	26,688,001,406	73.8%	49,392,896	48,508,620	50,030,974	875,303	1.9%
5	2009 Test	26,685,065,508	73.6%	49,641,284	48,752,334	50,282,196	902,683	3.1%
6	2010 Test	26,706,908,165	73.6%	49,740,117	48,848,926	50,381,862	937,960	3.9%

*Includes Scattered load and Street Lighting
2005 Mid-year: 843,262

Data Used

Monthly kWh Forecast

Forecast method: Multiple regression / Econometrics forecast
Data used: Jan. 1998 - Jun. 2006 kWh purchase by month

Table 1

	Col. 1	Col. 2
1	**Variable**	**Data Sources**
2	**Dependent variable:**	
3	Monthly kWh purchase	Monthly kWh purchase from the IESO and from the NUGs
4	**Independent variables:**	
5	Peak hour % of total hours in a month	Monthly peak hours as a % of total hours (16 peak hours on weekdays, excluding weekends and public holidays)
6	Ontario real GDP index	2007 GDP was derived from a consensus forecast from the six Schedule I Chartered banks (i.e. the average real GDP growth rate forecast by TD, BMO, CIBC, RBC, Scotia, and National bank); 2008-2010 GDP was forecasted based on historical actual (1998-2005)
7	Actual HDD	Recent 10-year (1996-2005) monthly average HDD obtained from Environment Canada at Station of Toronto Lester B. Pearson International Airport
8	Actual CDD	Recent 10-year (1996-2005) monthly average CDD obtained from Environment Canada at Station of Toronto Lester B. Pearson International Airport
9	Number of days in a month (squared)	Based on actual number of days in each month
10	Blackout dummy	Applied to the month of August 2003
11	Spring/fall dummy	Applied to spring and fall months of the year

Assumptions: Normal weather applied to forecast years 2007-2010 are defined as 10-year average HDD/CDD from 1996 to 2005.

Monthly System Load Factor Forecast

Forecast method: Time-series (Holt-Winters) forecast model
Data used: Jan. 1998 - Jun. 2006 system load factors by month

Monthly Peak kW Demand Forecast

Forecast method: Derived from kWh forecast and system load factors forecast results
kW demand = kWh /(system load factor X hours use)

Customer Growth Forecast (Statistical Forecast)

Forecast method: Historical trend and time- series forecast models were used to forecast number of customers by class 2007-2010
Data used: Historical actual number of customers by class

Table 2

	Col. 1	Col. 2	Col. 3
1	**Forecast Details (by customer class)**		
2	**Customer class**	**Time-series methods used**	**Historical data used**
3	Residential	Holt-Winters	Jan. 2002 - Jun. 2006
4	GS < 50kW	Historical trend	Jan. 2002 - Jun. 2006
5	GS 50-1K kW NI	Historical trend	Jan. 2002 - Jun. 2006
6	GS 50-1K kW IN	Holt-Winters	Jan. 2003 - Jun. 2006
7	GS 1K-5K kW	Holt-Winters	Jan. 2002 - Jun. 2006
8	Large user > 5K kW	Box Jenkins	Jan. 2002 - Jun. 2006

Customer Growth Forecast (Adjustment for Smart Meters Program)

On top of the natural customer growth forecast based on historical trends the mix of customers is expected to be altered significantly as a result of the Smart Meter program, and specifically the Government of Ontario's 'Installation of Smart Meters and Smart Sub-Metering Systems in Condominiums' legislation which calls for individually metered multi-residential units.

The forecast of customers for the residential sector in 2008 through 2010 anticipates that new residential condominium buildings in Toronto will incorporate individually metered units, and thus where previously the load associated with these customers would have been billed as a single General Service customer, it will now be billed as individual residential units. Additionally, it is anticipated that most existing multi-unit buildings will also be converted to individual meters by the end of 2010, and the associated load will convert from being bulk metered to individually metered.

Volumes, Revenues, Unit Revenues, Customer Count

Table 1: 2006-2010 Volumes (kWh, kW, Customer Count)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1	**Year**	**kWh Purchase**	**System Load Factors % WAG**	**kW-Network**	**kW-Line Connection**	**kW-Transformer Connection**	**Customer Count***	**Customer Growth YOY %**
2	2006 Actual	26,437,085,050	73.5%	49,292,194	48,378,238	49,671,411	855,453	1.4%
3	2007 Forecast	26,629,004,588	74.0%	49,313,200	48,431,774	49,951,630	858,663	0.4%
4	2008 Forecast	26,688,001,406	73.8%	49,392,896	48,508,620	50,030,974	875,303	1.9%
5	2009 Forecast	26,685,065,508	73.6%	49,641,284	48,752,334	50,282,196	902,683	3.1%
6	2010 Forecast	26,706,908,165	73.6%	49,740,117	48,848,926	50,381,862	937,960	3.9%

*Includes Scattered Load and Street Lighting
2005 (Mid Year): 843,262

Table 2: 2006-2010 Revenues, Unit Revenue Alternative 1 (distribution revenue per class customer), and Customer Count

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
1		**2006 Historical**			**2007 Bridge**			**2008 Test**			**2009 Test**			**2010 Test**		
2	**Class**	**Distribution Revenue ($)**	**Class Customer Count (Mid-Year)**	**Distribution Revenue per Customer ($)**	**Distribution Revenue ($)**	**Class Customer Count (Mid-Year)**	**Distribution Revenue per Customer ($)**	**Distribution Revenue ($)**	**Class Customer Count (Mid-Year)**	**Distribution Revenue per Customer ($)**	**Distribution Revenue ($)**	**Class Customer Count (Mid-Year)**	**Distribution Revenue per Customer ($)**	**Distribution Revenue ($)**	**Class Customer Count (Mid-Year)**	**Distribution Revenue per Customer ($)**
3	Residential (incl.WH)	169,444,986	597,435	284	171,887,189	600,541	286	206,634,579	617,157	335	229,809,256	644,567	357	252,470,011	679,914	371
4	GS < 50 kW (incl.WH)	58,555,976	67,004	874	60,664,759	66,989	906	69,858,602	66,934	1,044	73,548,602	66,878	1,100	77,019,664	66,823	1,153
5	GS Scattered load		1,466			1,466			1,466			1,466			1,466	
6	GS Scattered load connection	1,143,035	17,721	65	1,136,447	17,721	64	1,624,871	17,721	92	1,873,706	17,721	106	2,102,637	17,721	119
7	GS 50-1K kW NI	87,499,644	9,693	9,027	54,847,149	6,175	8,882	21,166,230	2,135	9,912	10,610,777	1,065	9,960	2,455,448	265	9,262
8	GS 50-1K kW IN	41,046,157	1,704	24,088	77,192,308	5,340	14,456	121,736,026	9,451	12,880	136,141,917	10,540	12,917	143,887,471	11,318	12,713
9	GS 1K-5K kW	48,236,220	521	92,584	48,360,733	521	92,858	52,887,587	528	100,124	54,964,330	536	102,615	55,750,308	543	102,660
10	Large user > 5K kW	17,891,812	48	372,746	17,885,912	49	365,019	20,324,563	49	414,787	21,492,441	49	438,621	22,201,312	49	453,088
11	Street lighting	1,661,445	159,861	10	1,664,665	159,861	10	4,100,628	159,861	26	5,214,380	159,861	33	6,395,740	159,861	40
12	**Total**	**425,479,276**	**855,453**		**433,639,162**	**858,663**		**498,333,086**	**875,303**		**533,655,409**	**902,683**		**562,282,591**	**937,960**	
13	W/O. Scattered Load and Street Lighting		676,405	629		679,615	638		696,255	716		723,635	737		758,912	741

Notes:
* 2006 and 2007 distribution revenues are annual total distribution revenues at OEB-approved rates
* 2008-2010 distribution revenues are annual total distribution revenues at proposed rates
* Distribution revenue per connection

Table 3: 2006-2010 Unit Revenue Alternative 2 (distribution revenue per kWh purchase)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
1	**2006 Historical**			**2007 Bridge**			**2008 Test**			**2009 Test**			**2010 Test**		
2	**Distribution revenue ($)**	**kWh purchase**	**Distribution revenue per kWh**	**Distribution revenue ($)**	**kWh purchase**	**Distribution revenue per kWh**	**Distribution revenue ($)**	**kWh purchase**	**Distribution revenue per kWh**	**Distribution revenue ($)**	**kWh purchase**	**Distribution revenue per kWh**	**Distribution revenue ($)**	**kWh purchase**	**Distribution revenue per kWh**
3	425,479,276	26,437,085,050	0.0161	433,639,162	26,629,004,588	0.0163	498,333,086	26,688,001,406	0.0187	533,655,409	26,685,065,508	0.0200	562,282,591	26,706,908,165	0.0211

Number of Customers by Class
(2006 Historical)

Table 1

	Col. 1	Col. 2	Col. 3
1	**Class**	**Number of Customers (Mid-Year)**	**Number of Customers (Year-end)**
2	Residential (including WH)	597,435	599,080
3	GS < 50 kW (including WH)	67,004	67,017
4	GS Scattered Load Customer	1,466	1,466
5	GS Scattered Load Connection	17,721	17,721
6	GS 50-1K kW NI	9,693	9,680
7	GS 50-1K kW IN	1,704	1,764
8	GS 1K-5K kW	521	516
9	Large User > 5K kW	48	49
10	Street Lighting	159,861	159,861
11	**Total**	**855,453**	**857,154**
12	Total (w/o Scattered load and Street Lighting)	676,405	678,106

Purchased kWh; Sales kWh and by Customer Class
(2006 Historical)

Table 1

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,437,085,050
3	Sales kWh	25,527,304,675
4	Residential (incl.WH)	5,351,746,739
5	GS < 50 kW (incl.WH)	2,471,461,092
6	GS Scattered load	58,365,236
7	GS 50-1K kW NI	6,142,889,156
8	GS 50-1K kW IN	3,660,118,648
9	GS 1K-5K kW	5,144,798,953
10	Large user > 5K kW	2,592,278,433
11	Street lighting	105,646,417
12	**Total Sales kWh**	**25,527,304,675**

Loss Factor
(2006 Historical)

Table 1: Calculations of Actual Distribution Loss Adjustment Factors for 2002 - 2006

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1		Calculations	**2002**	**2003**	**2004**	**2005**	**2006**
2	A1	Purchased kWh including SSLF 1.0045	27,070,380,307	26,517,052,119	26,417,144,859	27,312,085,342	26,449,417,229
3	A	"Wholesale" kWh (IESO) excluding SSLF 1.0045	26,988,506,740	26,398,259,950	26,298,800,257	27,189,731,550	26,330,928,053
4	B	"Wholesale" kWh for Large Use customer(s) (IESO)	2,895,256,240	2,606,165,401	2,630,137,387	2,599,239,226	2,628,829,559
5	C	Net "Wholesale" kWh (A)-(B)	24,093,250,500	23,792,094,548	23,668,662,871	24,590,492,324	23,702,098,494
6	D	"Retail" kWh (Distributor)	26,177,019,147	25,611,184,024	25,500,987,289	26,355,686,169	25,563,321,385
7	E	"Retail" kWh for Large Use Customers	2,855,000,730	2,569,929,397	2,593,568,077	2,563,099,523	2,592,278,433
8	F	Net "Retail" kWh (D)-(E)	23,322,018,417	23,041,254,627	22,907,419,212	23,792,586,646	22,971,042,952
9	G	Loss Factor for classes other than Large Use [(C)/(F)]	1.033	1.033	1.033	1.034	1.032
10	H	**Loss Factor for classes including Large Use [(A)/(D)]**	**1.031**	**1.031**	**1.031**	**1.032**	**1.030**
11	I	**Specific Supply Loss Factor**					**1.0045**
12	J	**Total Loss Factor**					**1.035**

kW: System; Network; Line Connection; Transformer Connection (2006 Historical)

Table 1

	Col. 1	Col. 2
1		**kW**
2	System (Network)	49,292,194
3	Line Connection	48,378,238
4	Transformer Connection	49,671,411

THESL Own Use kWh and kVA
(2006 Historical)

Table 1

	Col. 1	Col. 2
1	THESL's own use kWh	18,305,729
2	THESL's own use kVA	37,657

Overall Distribution Revenue and Unit Revenue
(2006 Historical)

Table 1: Revenue per Customer Class (by number of customers)

	Col. 1	Col. 2	Col. 3	Col. 4
1	**Class**	**Distribution Revenue from Revenue Model ($) ****	**Unit Revenue per Customer (mid-year) ***	**Unit Revenue per Customer (year-end) ***
2	Residential (incl.WH)	169,444,986	284	283
3	GS < 50 kW (incl.WH)	58,555,976	874	874
4	GS Scattered load customer	-	-	-
5	GS Scattered load connection	1,143,035	65	65
6	GS 50-1K kW NI	87,499,644	9,027	9,039
7	GS 50-1K kW IN	41,046,157	24,088	23,269
8	GS 1K-5K kW	48,236,220	92,584	93,481
9	Large user > 5K kW	17,891,812	372,746	365,139
10	Street lighting	1,661,445	10	10
11	**Total**	**425,479,276**	**629**	**627**

** Note 1: 2006 distribution revenue is based on annual 2006 OEB-approved distribution rates

* Note 2: For "Unit distribution revenue per class customer", the data is based on both mid-year number of customers and year-end number of customers of 2006.

Table 2: Alternative: Unit Revenue (revenue per kWh)

	Col. 1	Col. 2	Col. 3
1	**Total Overall Distribution Revenue**	**kWh Purchase**	**Unit Revenue per kWh**
2	425,479,276	26,437,085,050	0.0161

Number of Customers by Class
(2006 Historical Normalized - Same as Actuals)

Table 1

	Col. 1	Col. 2	Col. 3
1	**Class**	**Number of Customers (Mid-Year)**	**Number of Customers (Year-end)**
2	Residential (incl.WH)	597,435	599,080
3	GS < 50 kW (incl.WH)	67,004	67,017
4	GS Scattered load customer	1,466	1,466
5	GS Scattered load connection	17,721	17,721
6	GS 50-1K kW NI	9,693	9,680
7	GS 50-1K kW IN	1,704	1,764
8	GS 1K-5K kW	521	516
9	Large user > 5K kW	48	49
10	Street lighting	159,861	159,861
11	**Total**	**855,453**	**857,154**
12	W/O Scattered and Street Lighting	676,405	678,106

Purchased kWh; Sales kWh and by Customer Class
(2006 Historical Normalized)

Table 1

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,573,558,098
3	Sales kWh	25,627,789,323
4	Residential (incl.WH)	5,394,912,559
5	GS < 50 kW (incl.WH)	2,483,158,098
6	GS Scattered load	58,365,236
7	GS 50-1K kW NI	6,180,911,256
8	GS 50-1K kW IN	3,665,949,442
9	GS 1K-5K kW	5,147,832,391
10	Large user > 5K kW	2,591,013,924
11	Street lighting	105,646,417
12	**Total Sales kWh**	**25,627,789,323**

Loss Factor
(2006 Historical Normalized)

Table 1

	Col. 1	Col. 2
1	Total Loss Factor	1.037
2	Distribution Loss Factor	1.032
3	Specific Supply Loss Factor	1.0045

kW: System; Network; Line Connection; Transformer Connection
(2006 Historical Normalized)

Table 1

	Col. 1	Col. 2
1		**kW**
2	System (Network)	49,546,650
3	Line Connection	48,627,975
4	Transformer Connection	49,927,824

THESL Own Use kWh and kVA
(2006 Historical Normalized)

Table 1

	Col. 1	Col. 2
1	THESL's own use kWh	18,400,227
2	THESL's own use kVA	37,852

Overall Distribution Revenue and Unit Revenue
(2006 Historical Normalized)

Table 1: Revenue per Customer Class (by number of customers)

	Col. 1	Col. 2	Col. 3	Col. 4
1	**Class**	**Distribution Revenue Weather normalized ($) ****	**Unit Revenue per Customer (Mid-Year) ($) ***	**Unit Revenue per Customer (Year-End) ($) ***
2	Residential (incl.WH)	169,870,640	284	284
3	GS < 50 kW (incl.WH)	58,790,836	877	877
4	GS Scattered load customer		-	-
5	GS Scattered load connection	1,148,430	65	65
6	GS 50-1K kW NI	87,935,937	9,072	9,084
7	GS 50-1K kW IN	41,256,439	24,212	23,388
8	GS 1K-5K kW	48,462,062	93,017	93,919
9	Large user > 5K kW	17,975,935	374,499	366,856
10	Street lighting	1,667,412	10	10
11	**Total**	**427,107,692**	**631**	**630**

** Note 1: Distribution revenue is based on annual 2006 OEB-approved distribution rates

* Note 2: For "Unit distribution revenue per class customer", the data is based on both mid-year number of customers and year-end number of customers of 2006.

Table 2: Alternative: Unit Revenue (revenue per kWh)

	Col. 1	Col. 2	Col. 3
1	**Distribution Revenue Weather Normalized****	**kWh Purchase**	**Unit Revenue per kWh**
2	427,107,692	26,573,558,098	0.0161

Number of Customers by Class
(2006 EDR OEB-Approved)

Table 1

	Col. 1	Col. 2
1	**Class**	**Number of customers (Mid-Year)**
2	Residential (including WH)	597,210
3	GS < 50 kW (including WH)	66,505
4	GS Scattered Load Customer	1,438
5	GS Scattered Load Connection	13,408
6	GS 50-1K kW NI	9,550
7	GS 50-1K kW IN	1,682
8	GS 1K-5K kW	511
9	Large User > 5K kW	47
10	Street Lighting	159,861
11	**Total**	**850,212**
12	Total (w/o Scattered Load and Street Lighting)	675,505

Purchased kWh; Sales kWh and by Customer Class
(2006 EDR OEB-Approved)

Table 1

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,701,359,045
3	Sales kWh	25,782,484,200
4	Residential (including WH)	5,470,966,591
5	GS < 50 kW (including WH)	2,620,609,508
6	GS Scattered Load	54,396,775
7	GS 50-1K kW NI	6,174,749,298
8	GS 50-1K kW IN	3,667,466,273
9	GS 1K-5K kW	5,080,177,986
10	Large User > 5K kW	2,605,123,574
11	Street Lighting	108,994,196
12	**Total Sales kWh**	**25,782,484,200**

Loss Factor
(2006 EDR OEB-Approved)

Table 1

	Col. 1	Col. 2
1	Total Loss Factor	1.0356
2	Distribution Loss Factor	1.0310
3	Specific Supply Loss Factor	1.0045

kW: System; Network; Line Connection; Transformer Connection
(2006 EDR OEB-Approved)

Table 1

	Col. 1	Col. 2
1	**kW**	**kW**
2	System (Network)	48,885,267
3	Line Connection	48,028,177
4	Transformer Connection	49,553,450

THESL Own Use kWh and kVA
(2006 EDR OEB-Approved)

Table 1

	Col. 1	Col. 2
1	THESL's own use kWh	0
2	THESL's own use kVA	0

Note: In the 2006 EDR filing, THESL did not sperate out THESL's own use kWh and kVA.

Overall Distribution Revenue and Unit Revenue
(2006 EDR OEB-Approved)

Table 1: Distribution Revenue and Unit Revenue by Class per Customer

	Col. 1	Col. 2	Col. 3
1	**Class**	**Overall Distribution Revenue ($)**	**Unit Revenue Per Customer ($/Customer)**
2	Residential (including WH)	170,975,941	286
3	GS < 50 kW (including WH)	61,222,838	921
4	GS Scattered Load Customer		
5	GS Scattered Load Connection	1,053,904	79
6	GS 50-1K kW NI	88,963,646	9,316
7	GS 50-1K kW IN	41,467,720	24,654
8	GS 1K-5K kW	48,355,847	94,630
9	Large User > 5K kW	18,321,682	389,823
10	Street Lighting	1,649,871	10
11	**Total (including Transformer Allowamce)**	**432,011,450**	**640**

Table 2: Distribution Revenue and Unit Revenue by kWh

	Col. 1	Col. 2	Col. 3
1	**Overall Distribution Revenue ($)**	**kWh Purchase**	**Unit Revenue per kWh**
2	432,011,450	26,701,359,045	0.0162

2006 EDR OEB-Approved vs. Historical Normalized

Table 1: kWh Purchase

	Col. 1	Col. 2	Col. 3	Col. 4
1	**2006 EDR OEB-Approved (A)**	**Historical Normalized (B)**	**Variances (C=B- A)**	**Variance % (C / A)**
2	26,701,359,045	26,573,558,098	(127,800,947)	**-0.48%**

Note: The variance is partly due to the difference between Ontario Real GDP growth rate %; 2006 OEB-approved vs. 2006 historical

Table 2

	Col. 1	Col. 2	Col. 3	Col. 4
1		**2006 EDR OEB-Approved**	**2006 Historical (from RBC)**	**Variance in GDP (E)**
2	Ontario Real GDP growth rate %	2.9%	1.5%	-1.4%

Table 3

	Col. 1	Col. 2	Col. 3	Col. 4
1	**Real GDP Index (A)**	**Coefficient of GDP in Forecast (B)**	**Impact from Real GDP (C = A x B)**	**Variance from Ontario Real GDP Growth Rate % (C X E)**
2	1643.5	4,249,195	6,983,629,587	(99,167,540)

Historical Normalized vs. Bridge Year

Table 1: kWh Purchase

	Col. 1	Col. 2	Col. 3	Col. 4
1	**Historical Normalized (A)**	**Bridge Year (B)**	**Variances (C) = (B) - (A)**	**Variance % (C) / (A)**
2	26,573,558,098	26,629,004,588	55,446,490	**0.21%**

Variance Break-Down:

Table 2: Impact from Ontario Real GDP Growth

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Historical Normalized**	**Bridge Year**	**Variance in GDP**
2	Ontario Real GDP Growth Rate %	1.5%	2.4%	
3	Real GDP Index	1630.8	1681.2	50.4
4	Coefficient of GDP in Forecast	2,816,977	2,816,977	
5	Variance from Ontario Real GDP Growth	4,593,970,024	4,735,982,533	**142,012,509**

Table 3: Impact from Peak hours

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Historical Normalized**	**Bridge Year**	**Variance in Peak hours**
2	Peak Hours	4016	4032	16
3	Coefficient of Peak Hours	1,201,849	1,201,849	
4	Variance from Peak Hours	4,826,627,585	4,845,857,177	**19,229,592**

Table 4: Impact from CDM

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Historical Normalized**	**Bridge Year**	**Variance in CDM**
2	CDM load reduction	(140,540,697)	(266,066,046)	**(125,525,349)**

Note: Total variance explained from regression model (Tables 2 through 4): **35,716,752**

Bridge Year vs. Test Years

Table 1: kWh Purchase

	Col. 1	Col. 2	Col. 3	Col. 4
1	**Bridge Year 2007 (A)**	**Test Year 2008 (B)**	**Test Year 2009 (C)**	**Test Year 2010 (D)**
2	26,629,004,588	26,688,001,406	26,685,065,508	26,706,908,165
3	YOY Variances	(B - A)	(C - B)	(D - C)
4		58,996,818	- 2,935,898	21,842,657
5	YOY Variances %	0.22%	-0.01%	0.08%

2008 vs. 2007 Variances break-down :

Table 2: Impact from Ontario Real GDP Growth

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Bridge Year 2007 (A)**	**Test Year 2008 (B)**	**Variance in GDP**
2	Ontario Real GDP Growth Rate %	2.4%	2.4%	
3	Real GDP Index	1681.2	1721.4	40.1
4	Coefficient of GDP in Forecast	2,816,977	2,816,977	
5	Variance from Ontario Real GDP Growth	4,735,982,533	4,849,073,533	**113,091,001**

Table 3: Impact from Peak hours %

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Bridge Year 2007 (A)**	**Test Year 2008 (B)**	**Variance in Peak hours %**
2	Peak Hours %	552	553	1
3	Coefficient of Peak Hours %	4,926,997	4,926,997	
4	Variance from Peak Hours %	2,721,781,254	2,725,723,756	**3,942,503**

Table 4: Impact from CDM

		Col. 2	Col. 3	Col. 4
1		**Bridge Year 2007 (A)**	**Test Year 2008 (B)**	**Variance in CDM**
2	CDM load reduction	-	-63,719,412	-63,719,412

Note: 2008 vs. 2007 total variance explained from regression model (Tables 2 through 4): 53,314,091

2009 vs. 2008 Variances break-down :

Table 5: Impact from Ontario Real GDP Growth

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Test Year 2008 (B)**	**Test Year 2009 (C)**	**Variance in GDP**
2	Ontario Real GDP Growth Rate %	2.4%	2.3%	
3	Real GDP Index	1721.4	1761.6	40.2
4	Coefficient of GDP in Forecast	2,816,977	2,816,977	
5	Variance from Ontario Real GDP Growth	4,849,073,533	4,962,422,707	**113,349,174**

Table 6: Impact from Peak hours %

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Test Year 2008 (B)**	**Test Year 2009 (C)**	**Variance in Peak Hours %**
2	Peak Hours %	553	553	-1
3	Coefficient of Peak Hours %	4,926,997	4,926,997	
4	Variance from Peak Hours %	2,725,723,756	2,722,840,823	**(2,882,933)**

Table 7: Impact from Leap Year

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Test Year 2008 (B)**	**Test Year 2009 (C)**	**Variance in Leap Year**
2	Days in February (squared)	841	784	-57
3	Coefficient of Days in a Month (squared)	994,434	994,434	
4	Variance from Leap Year	836,318,826	779,636,099	**(56,682,727)**

Table 8: Impact from CDM

		Col. 2	Col. 3	Col. 4
1		**Test Year 2008 (B)**	**Test Year 2009 (C)**	**Variance in CDM**
2	CDM load reduction	-	-63,719,412	-63,719,412

Note: 2009 vs. 2008 total variance explained from regression model (Tables 5 through 8): (9,935,898)

2010 vs. 2009 Variances Break-Down :

Table 9: Impact from Ontario Real GDP Growth

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Test Year 2009 (C)**	**Test Year 2010 (D)**	**Variance in GDP**
2	Ontario Real GDP growth rate %	2.3%	2.3%	
3	Real GDP index	1761.6	1801.9	40.2
4	Coefficient of GDP in forecast	2,816,977	2,816,977	
5	Variance from Ontario Real GDP growth	4,962,422,707	5,075,771,881	**113,349,174**

Table 10: Impact from Peak Hours %

	Col. 1	Col. 2	Col. 3	Col. 4
1		**Test Year 2009 (C)**	**Test Year 2010 (D)**	**Variance in Peak Hours %**
2	Peak Hours %	553	553	0
3	Coefficient of Peak Hours %	4,926,997	4,926,997	
4	Variance from Peak Hours %	2,722,840,823	2,723,194,013	**353,190**

Table 11: Impact from CDM

		Col. 2	Col. 3	Col. 4
1		**Test Year 2009 (C)**	**Test Year 2010 (D)**	**Variance in CDM**
2	CDM load reduction	-	-31,859,706	-31,859,706

Note: 2010 vs. 2009 total variance explained from regression model (Tables 9 through 11): 81,842,657

Normalized, Actual and Forecast Consumption by Class

Table 1: Actual kWh Consumption per Customer by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
1		**2002 Actual**	**2003 Actual**	**2004 Actual**	**2005 Actual**	**2006 Actual**
2	Residential (including WH)	9,651	9,198	9,177	9,629	8,958
3	GS < 50 kW (including WH)	39,493	38,604	38,150	39,448	36,885
4	GS Scattered Load	5,350	4,173	4,029	3,967	2,946
5	GS 50-1K kW NI	762,632	700,075	672,860	684,004	633,745
6	GS 50-1K kW IN	2,643,659	2,323,006	2,264,227	2,249,366	2,147,957
7	GS 1K-5K kW	10,515,901	10,404,896	10,109,919	10,171,293	9,874,854
8	Large User > 5K kW	62,065,233	55,868,030	55,182,300	54,534,032	54,005,801
9	Street Lighting	670	671	681	684	661

Table 2: Normalized Actual and Forecast kWh Consumption per Customer by Class
(Normalized actual 2002-2006 and forecast 2007-2010)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
1		**2002 Normalized**	**2003 Normalized**	**2004 Normalized**	**2005 Normalized**	**2006 Normalized**	**2007 Forecast**	**2008 Forecast**	**2009 Forecast**	**2010 Forecast**
2	Residential (including WH)	9,415	9,167	9,364	9,314	9,030	9,037	8,910	8,708	8,510
3	GS < 50 kW (including WH)	38,892	38,649	38,718	38,536	37,060	38,383	38,478	38,481	38,533
4	GS Scattered Load*	5,350	4,173	4,029	3,967	2,946	3,255	3,270	3,279	3,285
5	GS 50-1K kW NI	748,454	683,268	681,783	668,850	637,668	628,908	639,023	621,753	575,747
6	GS 50-1K kW IN	2,562,972	2,323,362	2,297,592	2,217,602	2,151,379	1,126,423	897,836	859,639	830,904
7	GS 1K-5K kW	10,362,588	10,411,091	10,227,348	9,992,690	9,880,676	9,734,987	9,629,926	9,508,055	9,391,244
8	Large User > 5K kW	61,404,716	55,929,428	55,679,984	53,777,557	53,979,457	52,619,498	52,855,925	52,981,396	53,086,705
9	Street Lighting*	670	671	681	684	661	686	689	691	692

*no impact from weather

Customer Additions Forecast by Rate Class

Table 1: Number of Customer by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
1	**Rate Class**	**Residential (including WH)**	**GS < 50 kW (including WH)**	**GS 50-1K kW NI**	**GS 50-1K kW IN**	**GS 1K-5K kW**	**Large User > 5K kW**	**GS Scattered Load**	**Street Lighting**	**Total**	**Total (w/o streetlights)**	**Total w/o Streetlights and Scattered Load**
2	2002 Actual	586,714	67,274	9,641	886	482	46	13,766	159,821	838,630	678,809	665,043
3	2003 Actual	590,109	67,064	9,484	1,424	497	47	13,094	159,821	841,540	681,719	668,625
4	2004 Actual	594,976	66,505	9,621	1,525	498	47	14,450	159,821	847,443	687,622	673,172
5	2005 Actual	597,469	67,147	9,871	1,627	517	47	13,408	159,861	849,947	690,086	676,678
6	2006 Actual	599,080	67,017	9,680	1,764	516	49	17,721	159,861	855,688	695,827	678,106
7	2007 Forecast	604,842	66,961	2,671	8,900	525	49	17,721	159,861	861,529	701,668	683,947
8	2008 Forecast	629,617	66,906	1,600	10,001	532	49	17,721	159,861	886,287	726,426	708,705
9	2009 Forecast	659,663	66,850	530	11,076	539	49	17,721	159,861	916,290	756,429	738,708
10	2010 Forecast	700,310	66,795	0	11,558	547	49	17,721	159,861	956,841	796,980	779,259

Table 2: Addition of Numbers of Customer by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
1	**Rate Class**	**Residential (including WH)**	**GS < 50 kW (including WH)**	**GS 50-1K kW NI**	**GS 50-1K kW IN**	**GS 1K-5K kW**	**Large User > 5K kW**	**GS Scattered Load**	**Street Lighting**	**Total**	**Total (w/o streetlights)**	**Total w/o Streetlights and Scattered Load**
2	2003 Actual	3,395	-210	-157	538	15	1	-672	0	2,910	2,910	3,582
3	2004 Actual	4,867	-559	137	101	1	0	1,355	0	5,902	5,902	4,547
4	2005 Actual	2,493	642	250	102	19	0	-1,042	40	2,504	2,464	3,506
5	2006 Actual	1,611	-130	-191	137	-1	2	4,314	0	5,742	5,742	1,428
6	2007 Forecast	5,762	-56	-7,009	7,136	9	0	0	0	5,841	5,841	5,841
7	2008 Forecast	24,775	-56	-1,070	1,101	7	0	0	0	24,758	24,758	24,758
8	2009 Forecast	30,047	-55	-1,070	1,075	7	0	0	0	30,003	30,003	30,003
9	2010 Forecast	40,647	-55	-530	482	7	0	0	0	40,551	40,551	40,551

Table 3: % Addition of Numbers of Customers by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
1	**Rate Class**	**Residential (including WH)**	**GS < 50 kW (including WH)**	**GS 50-1K kW NI**	**GS 50-1K kW IN**	**GS 1K-5K kW**	**Large User > 5K kW**	**GS Scattered Load**	**Street Lighting**	**Total**	**Total (w/o streetlights)**	**Total w/o Streetlights and Scattered Load**
2	2003 Actual	0.6%	-0.3%	-1.6%	60.8%	3.1%	2.2%	-4.9%	0.0%	0.3%	0.4%	0.5%
3	2004 Actual	0.8%	-0.8%	1.4%	7.1%	0.2%	0.0%	10.3%	0.0%	0.7%	0.9%	0.7%
4	2005 Actual	0.4%	1.0%	2.6%	6.7%	3.8%	0.0%	-7.2%	0.0%	0.3%	0.4%	0.5%
5	2006 Actual	0.3%	-0.2%	-1.9%	8.4%	-0.2%	4.3%	32.2%	0.0%	0.7%	0.8%	0.2%
6	2007 Forecast	1.0%	-0.1%	-72.4%	404.5%	1.6%	0.0%	0.0%	0.0%	0.7%	0.8%	0.9%
7	2008 Forecast	4.1%	-0.1%	-40.1%	12.4%	1.4%	0.0%	0.0%	0.0%	2.9%	3.5%	3.6%
8	2009 Forecast	4.8%	-0.1%	-66.9%	10.7%	1.4%	0.0%	0.0%	0.0%	3.4%	4.1%	4.2%
9	2010 Forecast	6.2%	-0.1%	-100.0%	4.4%	1.4%	0.0%	0.0%	0.0%	4.4%	5.4%	5.5%

Note: For an explanation of forecast methodology of the additions in customer by rate class, please refer to Exhibit K1 Tab 1 Schedule 1

10-year Historical HDD and CDD

Table 1: HDD

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
1	HDD											
2	**Month**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**10 years avg HDD**
3	Jan	765	757	625	750	739	685	572	815	849	770	733
4	Feb	690	593	512	548	613	588	540	699	632	616	603
5	Mar	646	600	492	551	419	567	546	581	487	609	550
6	Apr	408	367	282	297	339	294	330	373	332	307	333
7	May	206	261	59	97	140	112	228	178	159	189	163
8	Jun	21	21	55	25	35	30	36	43	44	9	32
9	Jul	10	12	1	-	7	9	-	0	4	-	4
10	Aug	3	17	3	8	12	-	0	2	13	0	6
11	Sep	72	87	40	49	100	74	22	55	30	23	55
12	Oct	273	267	223	268	213	233	292	276	226	220	249
13	Nov	512	467	393	368	432	326	445	399	379	388	411
14	Dec	572	586	535	579	780	505	619	562	643	665	605
15	**Total**	**4,177**	**4,034**	**3,220**	**3,539**	**3,826**	**3,420**	**3,630**	**3,982**	**3,798**	**3,797**	**3,742**

Table 2: CDD

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
1	CDD											
2	**Month**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**10 years avg CDD**
3	Jan	-	-	-	-	-	-	-	-	-	-	-
4	Feb	-	-	-	-	-	-	-	-	-	-	-
5	Mar	-	-	-	-	-	-	-	-	-	-	-
6	Apr	-	-	-	-	-	1	8	2	-	-	1
7	May	9	-	29	19	24	12	8	-	9	1	11
8	Jun	38	73	82	96	41	80	70	53	32	146	71
9	Jul	60	103	101	197	72	101	192	118	86	189	122
10	Aug	87	47	118	79	93	160	143	128	60	141	105
11	Sep	27	12	45	49	35	36	88	24	41	52	41
12	Oct	-	3	-	-	1	2	10	-	2	8	3
13	Nov	-	-	-	-	-	-	-	-	-	-	-
14	Dec	-	-	-	-	-	-	-	-	-	-	-
15	**Total**	**221**	**238**	**375**	**440**	**266**	**392**	**519**	**326**	**229**	**536**	**354**

Economic Assumptions

Notes on the 2007 Ontario Real GDP Index:

The 2007 Ontario real GDP index was derived from the 2007 Ontario real GDP growth rate %.

The 2007 Ontario real GDP growth rate % was determined by a consensus forecast from the six Schedule I Chartered banks (the average real GDP growth rate forecast by TD, BMO, CIBC, Scotia, RBC, and National bank) at 2.4% as shown in the table below:

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1	**2007 Ontario Real GDP growth rate % from six Schedule I chartered banks**							
2	**%**	**BMO**	**TD**	**CIBC**	**Scotial Bank**	**RBC**	**National Bank**	**Annual AVG %**
3	2007	3.0	2.3	1.6	2.3	2.8	2.4	**2.4**

Number of Customers by Class
(2007 Bridge Year Forecast)

Table 1

	Col. 1	Col. 2
1	**Class**	**Number of customers (Mid-Year)**
2	Residential (including WH)	600,541
3	GS < 50 kW (including WH)	66,989
4	GS Scattered Load Customer	1,466
5	GS Scattered Load Connection	17,721
6	GS 50-1K kW NI	6,175
7	GS 50-1K kW IN	5,340
8	GS 1K-5K kW	521
9	Large User > 5K kW	49
10	Street Lighting	159,861
11	**Total**	**858,663**
12	Total (w/o Scattered Load and Street Lighting)	679,615

Purchased kWh; Sales kWh and by Customer Class
(2007 Bridge Year Forecast)

Table 1

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,629,004,588
3	Sales kWh	25,712,524,748
4	Residential (including WH)	5,427,215,744
5	GS < 50 kW (including WH)	2,571,222,435
6	GS Scattered Load	57,690,475
7	GS 50-1K kW NI	3,883,672,036
8	GS 50-1K kW IN	6,014,689,498
9	GS 1K-5K kW	5,070,010,069
10	Large User > 5K kW	2,578,355,394
11	Street Lighting	109,669,097
12	**Total Sales kWh**	**25,712,524,748**

Loss Adjustment Factors Update
(2007 Bridge Year Forecast)

Table 1

	Col. 1	Col. 2
1	Total Loss Factor	1.0356
2	Distribution Loss Factor	1.0310
3	Specific Supply Loss Factor	1.0045

kW: System; Network; Line Connection; Transformer Connection
(2007 Bridge Year Forecast)

Table 1

	Col. 1	Col. 2
1		**kW**
2	System (Network)	49,313,200
3	Line Connection	48,431,774
4	Transformer Connection	49,951,630

THESL Own Use kWh and kVA
(2007 Bridge Year Forecast)

Table 1

	Col. 1	Col. 2
1	THESL's own use kWh	17,675,140
2	THESL's own use kVA	36,306

Number of Customers by Class

Table 1: 2008 Test Year

	Col. 1	Col. 2
1	**Class**	**Number of customers (Mid-Year)**
2	Residential (including WH)	617,157
3	GS < 50 kW (including WH)	66,934
4	GS Scattered Load Customer	1,466
5	GS Scattered Load Connection	17,721
6	GS 50-1K kW NI	2,135
7	GS 50-1K kW IN	9,451
8	GS 1K-5K kW	528
9	Large User > 5K kW	49
10	Street Lighting	159,861
11	**Total**	**875,303**
12	Total (w/o Scattered load and Street Lighting)	696,255

Table 2: 2009 Test Year

	Col. 1	Col. 2
1	**Class**	**Number of customers (Mid-Year)**
2	Residential (including WH)	644,567
3	GS < 50 kW (including WH)	66,878
4	GS Scattered Load Customer	1,466
5	GS Scattered Load Connection	17,721
6	GS 50-1K kW NI	1,065
7	GS 50-1K kW IN	10,540
8	GS 1K-5K kW	536
9	Large User > 5K kW	49
10	Street Lighting	159,861
11	**Total**	**902,683**
12	Total (w/o Scattered load and Street Lighting)	723,635

Table 3: 2010 Test Year

	Col. 1	Col. 2
1	**Class**	**Number of customers (Mid-Year)**
2	Residential (including WH)	679,914
3	GS < 50 kW (including WH)	66,823
4	GS Scattered Load Customer	1,466
5	GS Scattered Load Connection	17,721
6	GS 50-1K kW NI	265
7	GS 50-1K kW IN	11,318
8	GS 1K-5K kW	543
9	Large User > 5K kW	49
10	Street Lighting	159,861
11	**Total**	**937,960**
12	Total (w/o Scattered load and Street Lighting)	758,912

Purchased kWh; Sales kWh and by Customer Class

Table 1: 2008 Test Year

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,688,001,406
3	Sales kWh	25,769,537,891
4	Residential (including WH)	5,498,828,031
5	GS < 50 kW (including WH)	2,575,446,564
6	GS Scattered Load	57,950,907
7	GS 50-1K kW NI	1,364,599,404
8	GS 50-1K kW IN	8,485,862,596
9	GS 1K-5K kW	5,086,725,921
10	Large User > 5K kW	2,589,940,302
11	Street Lighting	110,184,165
12	**Total Sales kWh**	**25,769,537,891**

Table 2: 2009 Test Year

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,685,065,508
3	Sales kWh	25,766,749,611
4	Residential (including WH)	5,613,078,765
5	GS < 50 kW (including WH)	2,573,543,699
6	GS Scattered Load	58,101,913
7	GS 50-1K kW NI	662,344,787
8	GS 50-1K kW IN	9,060,309,140
9	GS 1K-5K kW	5,092,879,460
10	Large User > 5K kW	2,596,088,397
11	Street Lighting	110,403,450
12	**Total Sales kWh**	**25,766,749,611**

Table 3: 2010 Test Year

	Col. 1	Col. 2
1	**Class**	**kWh**
2	Purchased kWh	26,706,908,165
3	Sales kWh	25,787,863,889
4	Residential (including WH)	5,785,918,437
5	GS < 50 kW (including WH)	2,574,909,409
6	GS Scattered Load	58,219,008
7	GS 50-1K kW NI	152,633,152
8	GS 50-1K kW IN	9,404,366,328
9	GS 1K-5K kW	5,099,972,675
10	Large User > 5K kW	2,601,248,554
11	Street Lighting	110,596,326
12	**Total Sales kWh**	**25,787,863,889**

Loss Factors

Table 1: 2008 Test Year

	Col. 1	Col. 2
1	Total Loss Factor	1.0356
2	Distribution Loss Factor	1.0310
3	Specific Supply Loss Factor	1.0045

Table 2: 2009 Test Year

	Col. 1	Col. 2
1	Total Loss Factor	1.0356
2	Distribution Loss Factor	1.0310
3	Specific Supply Loss Factor	1.0045

Table 3: 2010 Test Year

	Col. 1	Col. 2
1	Total Loss Factor	1.0356
2	Distribution Loss Factor	1.0310
3	Specific Supply Loss Factor	1.0045

kW: System; Network; Line Connection; Transformer Connection

Table 1: 2008 Test Year

	Col. 1	Col. 2
1		**kW**
2	System (Network)	49,392,896
3	Line Connection	48,508,620
4	Transformer Connection	50,030,974

Table 2: 2009 Test Year

	Col. 1	Col. 2
1		**kW**
2	System (Network)	49,641,284
3	Line Connection	48,752,334
4	Transformer Connection	50,282,196

Table 3: 2010 Test Year

	Col. 1	Col. 2
1		**kW**
2	System (Network)	49,740,117
3	Line Connection	48,848,926
4	Transformer Connection	50,381,862

THESL Own Use kWh and kVA

Table 1: 2008 Test Year

	Col. 1	Col. 2
1	THESL's own use kWh	18,851,613
2	THESL's own use kVA	38,780

Table 2: 2009 Test Year

	Col. 1	Col. 2
1	THESL's own use kWh	18,710,226
2	THESL's own use kVA	38,489

Table 3: 2010 Test Year

	Col. 1	Col. 2
1	THESL's own use kWh	18,523,124
2	THESL's own use kVA	38,105

COST OF POWER

COST OF POWER FORECAST

Cost of power is an input into the working capital requirement calculations.

THESL's system cost of power expense forecast is derived using a two-step process. First, THESL forecasts electricity spot prices based on historical trends from May 2002 to June 2006. This price forecast is applied to the forecast of purchased kWh to derive the cost of power expense for purchased electricity.

Second, THESL has used historical average ratios between System Line Connection kW and System kW and between System Transformer Connection kW and System kW. These historical ratios are then applied to THESL System kW forecast to derive Transmission System Line Connection kW and Transmission System Transformer Connection kW forecasts. The current line connection and system transformer connection rates are applied to the relevant transmission kW quantities to derive the Transmission cost of power expenses.

In addition to those cost of power expenses, OEB-approved rates for Wholesale Market Services (currently set at $5.20/MWh) and Rural Rate Assistance (currently set at $1.00/MWh) are applied to the purchased kWh forecast to derive the estimated costs for those services. Hydro One low voltage charges and applicable credits (e.g., switchgear credits) are also accounted for in the overall cost of power expense. Cost of power expense for THESL's own use of electricity is deducted from THESL's total cost of power expenses.

Details of the cost of power forecast are provided in Exhibit K1, Tab 8, Schedule 2.

Cost of Power

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	**($ Millions)**	**2006 Historical**	**2006 OEB-Approved**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
2	Energy	1,408.4	1,478.3	1,507.4	1,510.7	1,510.6	1,511.8
3	Transmission	245.5	244.9	247.3	247.7	249.0	249.5
4	WMS	105.3	138.8	138.5	138.8	138.8	138.9
5	RRA	26.3	26.7	26.6	26.7	26.7	26.7
6	Own use deduction	(1.3)	0	(1.3)	(1.3)	(1.3)	(1.3)
7	**Total COP**	**1,784.1**	**1,888.7**	**1,918.5**	**1,922.6**	**1,923.7**	**1,925.6**

Cost of Power Inputs

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1	**Comoponents**	**Inputs**	**2006 Historical**	**2006 OEB-Approved**	**2007 Bridge**	**2008 Test**	**2009 Test**	**2010 Test**
2	Energy	GWh Purchased	26,437	26,701	26,629	26,688	26,685	26,707
3		Energy Price (cents)	5.33	5.54	5.66	5.66	5.66	5.66
4	Transmission	System MW at price of $2.83 per kW	49,292	48,885	49,313	49,393	49,641	49,740
5		System Line Connection MW at price of $0.82 per kW	48,378	48,028	48,432	48,509	48,752	48,849
6		System Transformer Conneciton MW at price of $1.50 per kW	49,671	49,553	49,952	50,031	50,282	50,382
7	WMS	Price $ per kWh	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
8	RRA	Price $ per kWh	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010
9	Own use deduction	Own use GWh	18	N/A*	18	19	19	19

* Own use kWh not separately identified in 2006.

COST ALLOCATION

THESL's total revenue requirement, as described in Exhibit J1, is allocated to rate classes as the basis for determining distribution rates for the test years.

Allocation methodologies for the 2006 and 2007 rate years, as developed by the OEB's EDR models, assumed maintenance of the shares of revenue class recovery as were initially determined as part of the 1999 rate unbundling.

In June 2005, the OEB initiated a review of cost allocation in the distribution sector. The Cost Allocation Review (EB-2005-0317) involved consultations with interested parties, including distributors and ratepayer representatives. THESL actively participated in the process.

The result of these extensive consultations, which occurred over the course of more than a year, was an OEB report on cost allocation methodologies, and a cost allocation model. All LDCs were required to submit to the OEB the cost allocation model populated with approved data from the 2006 rate filings. THESL submitted its model results in January 2007 and Table 1 below summarizes the results by rate class.

Table 1: 2006 Cost Allocation Results

Rate Class	Revenue/Cost Ratio (%)	Revenue less Costs ($ Millions)	ROE (%)
Residential	84.8	(33.1)	-2.1
General Service <50kW	94.7	(3.7)	-5.1
General Service 50-1000kW Non-Interval	131.7	22.6	29.0
General Service 50-1000kW Interval	140.5	12.7	31.9
Intermediate 1000-5000kW	148.0	17.9	36.3
Large User	114.8	2.8	15.3
Streetlighting	10.7	(17.9)	-52.6
Unmetered Scattered Load	44.3	(1.4)	-27.7

The results indicate that based on 2006 rates and costs, the residential, GS<50 kW, unmetered scattered load and streetlighting rate classes are recovering less than the costs of service. The GS 50-1000kW, Intermediate 1000-5000 kW, and the large users classes recover more than the cost of service.

For the purposes of determining cost allocations for the 2008-2010 test years, THESL has updated the data to reflect the test year financial and load information, and applied the OEB Cost Allocation Model, with some minor modifications (as discussed below).

The results of the cost allocation, which show the revenue/cost ratios after applying the proposed rates in each test year, are summarized in Table 2 below.

Table 2: Revenue / Cost Ratios (%)

Rate Class	2006	2008	2009	2010
Residential	84.8	85.0	86.2	89.0
General Service <50kW	94.7	97.6	100.5	98.0
General Service 50-1000kW	140.5	130.5	126.7	123.9
Intermediate 1000-5000kW	148.0	136.8	132.8	127.5
Large Use	114.8	110.3	108.6	105.9
Streetlighting	10.7	25.1	31.4	38.7
Unmetered Scattered Load	44.3	48.2	70.7	79.1

Note: 2006 GS 50-1000kW is for interval metered subclass

Exhibit L1, Tab 2, Schedules 1 to 23 provide detailed inputs and outputs from the Cost Allocation model for each test year.

COST ALLOCATION MODEL

For the purposes of this filing, THESL has not undertaken an internal THESL-specific cost allocation exercise from scratch. Cost allocation estimation is a time consuming and expensive undertaking. The last cost allocation exercise undertaken by THESL prior to the recent OEB-mandated cost allocation study was in 2000. That study was undertaken as an input into the rate unbundling of the time. THESL believes the OEB's recent cost allocation exercise developed for all provincial electric utilities represents a reasonable approach and adopts it generally for the purposes of this filing. As noted in our general comments in the January Cost Allocation Informational Filing, we believe it provides a solid foundation for further evaluation of LDC specific cost allocation and rate design. As the timing of that exercise is being followed fairly closely by THESL's 2008-2010 rate filing, THESL is comfortable applying the model and methodology to prospective costs and directionally to the development of rates.

The OEB's cost allocation model is designed on sound cost allocation principles. The primary principal is that costs should be allocated to those customer classes causing the various costs.

Cost allocation generally is done in three steps: Functionalization, Categorization and Allocation. In the functionalization step, costs are aggregated into homogenous groups as defined by functions within the utility. In the case of the OEB's Cost Allocation Model, functionalization was achieved by allocating utility costs to the various USofA accounts, with some further refinement in some categories for primary and secondary related costs, and aggregation of some USofA accounts where the greater level of account-by-account detail is not required for allocation.

In the categorization step, each of the cost categories determined in the functionalization step are categorized as either demand-related (related to the peak demands on the system), customer-related (related to the number of customers of the utility), or jointly demand- and customer-related (related to both demand on the system and number of customers). Where costs are categorized as jointly demand- and customer-related, the proportions of each are determined in the Cost Allocation Model using a Minimum System approach. This approach determines the customer-related proportion by estimating the minimum system that would be needed to serve the minimum load requirements of customers. The remainder of costs are considered to be demand-related. The OEB's Cost Allocation model does not attempt to estimate the minimum system for each utility individually, but uses results of past studies to determine a generic customer/demand split based on utility densities. THESL has no information that would lead it to differ from the generic splits as applied in the OEB's model, and accepts the values as reasonable.

The final step is the allocation of the demand- and customer-related costs based on various allocators. THESL has adopted the allocators used in the Cost Allocation model, including the use of 4 NCP for allocating primary and secondary asset costs.

IMPLEMENTATION OF COST ALLOCATION RESULTS

As is described more fully in Exhibit M1, Tab 1, Schedule 1, the results of the cost allocation model are only one input into the development of rates for the test year. Other considerations such as rate impacts on a particular class or customer group within a class, potential for rate whiplash (rates changing dramatically and directionally from one year to the next) and the OEB's announced Rate Design process also factor into the development of distribution rates.

For that reason, while THESL has designed rates for the test years to incorporate information from the cost allocation model, the revenue-cost ratios are not necessarily moved to unity for each rate class. Exhibit M1, Tab 1, Schedule 1 describes in more detail the implementation in rates of the cost allocation results.

Of particular note are the results for the Streetlighting and Unmetered Scattered Load rate classes. The results of the Cost Allocation Model for these classes indicate a significant under-recovery of costs. THESL believes the primary reason for this apparent over-allocation of costs is:

- For streetlighting, THESL's number of streetlights per connection to the secondary system is quite low – 1.8 streetlights per connection – resulting in streetlights making up a significant proportion of total connections (more than ten percent). Since the number of connections is used to allocate approximately 40 percent of all non-meter related costs, this results in a significant allocation of costs to streetlights. It is not at all obvious that this allocation is appropriate. The design of streetlight connections in Toronto reflects operational considerations in

the areas of ease of maintenance and reliability. Other provincial systems, which design their streetlighting connections differently may have different reasons, and may show higher streetlights per connection, and hence allocate lower primary and secondary costs to each streetlight. These differences in design do not necessarily imply that allocation by number of connections is the best allocator of these costs.

While the OEB has not released the results of the 2006 Cost Allocation Informational filing, THESL understands that many other utilities show similar results (significant under-recovery) for these rate classes.

The Cost Allocation Model was developed with the understanding that it would be the first step in reviewing the allocation of costs for the electric utilities in the provinces. Combined with the reasons described above, THESL believes it is premature to make significant adjustments to the rates for these rate classes required to move them to full cost-recovery based on the current model.

MODIFICATIONS TO THE OEB MODEL

THESL has made some minor changes to the OEB's Cost Allocation Model for the purposes of this filing.

The first change deals with the manner in which transformation costs and credits are handled in the model. The current model logic adds the transformer allowance provided to customers who own their own transformation facilities as an expense to the two following accounts:

- 5055 – Underground Distribution Transformer; and
- 5160 – Maintenance of Line Transformers

The model distributes these costs only to the customers that utilize the LDC's line transformers (LTNCP allocator). Customers that do not utilize the LDC transformation assets are not allocated any of these transformer allowance costs. THESL does not believe this is an appropriate allocation of the transformer allowance since the allowance itself is intended to offset all transformation costs.

THESL has modified the model through identifying the transformer allowance provided to specific rate classes, and directly assigned the appropriate transformer costs to those rate classes.

The second change involved ensuring that the working capital values in the Cost Allocation Model reflect the results of the Navigant study, as outlined in Exhibit D1, Tab 15, Schedule 1. The original Cost Allocation Model applied the 15 percent of manageable expenses methodology that was included in the 2006 OEB EDR model.

The final change involved updating the meter capital and service cost estimates used in the Cost Allocation model for allocating meter and meter service costs. The values in these tables have been updated and made consistent with the anticipated costs in the test years. This change ensures that the relative meter capital and service costs are allocated appropriately to the respective classes.

Residential

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

General Service Less Than 50 kW

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.

Non Interval Meters - 50 to 1,000 kW

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 and with a non-interval meter. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

Interval Meters - 50 to 1,000 kW

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 and with an interval meter. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

1,000 to 5,000 kW

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.

Large Use

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.

Standby - General Service 50 - 1,000 kW

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 that has Load Displacement Generation and requires THESL to provide back-up service. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units

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

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 that has Load Displacement Generation and requires THESL to provide back-up service. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

Standby - Large Use

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 that has Load Displacement Generation and requires THESL to provide back-up service.

Unmetered Scattered Load

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

Street Lighting

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

2007 TRIAL BALANCE

CALCULATIONS: (Minimum Reporting Requirement)

Land and Buildings	63,543,505	63,543,505	0	59,491,716	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	2,042,507	2,042,507	0	2,042,507	1815
DS	160,292,889	160,292,889	0	154,675,548	1820
Poles, Wires	2,206,311,296	2,206,311,296	0	2,150,197,704	1830, 1835, 1840, 1845
Line Transformers	590,266,670	590,266,670	0	567,777,138	1850
Services and Meters	180,213,917	180,213,917	0	173,828,546	1855, 1860
General Plant	106,180,057	106,180,057	0	104,581,445	1908, 1910
Equipment	152,782,819	152,782,819	0	144,591,620	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	176,005,434	176,005,434	0	161,559,897	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	1565 (new account)
Other Distribution Assets	61,548,012	61,548,012	0	59,060,708	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-206,012,579	-206,012,579	0	-189,012,985	1995
Accumulated Amortization	-1,870,181,709	-1,870,181,709	0	-1,804,382,078	2105, 2120
Non-Distribution Asset	-0	-0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	75,901,752	75,901,752	0	75,901,752	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 151
Liability	-0	-0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 251
Equity	-0	-0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,352,085,634	-2,352,085,634	0	-2,352,085,634	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	-0	4080
Late Payment Charges	-4,080,000	-4,080,000	0	-4,080,000	4225
Specific Service Charges	-6,783,697	-6,783,697	0	-6,783,697	4235
Other Distribution Revenue	-7,181,593	-7,181,593	0	-7,181,593	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-12,461,312	-12,461,312	0	-12,461,312	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,918,533,604	1,918,533,604	0	1,918,533,604	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	50,904,714	50,904,714	0	50,904,714	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	40,848,274	40,848,274	0	40,848,274	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
Billing and Collection (Working Capital)	26,252,492	26,252,492	0	26,252,492	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,349,933	3,349,933	0	3,349,933	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	3,569,855	3,569,855	0	3,569,855	5415
Administrative and General Expenses (Working Capital)	30,059,772	30,059,772	0	30,059,772	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,265,000	2,265,000	0	2,265,000	5635, 6210
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	7,000,000	5335
Advertising Expenses	-0	-0	0	-0	5515, 5660
Charitable Contributions	-0	-0	0	-0	6205
Amortization of Assets	132,414,733	132,414,733	0	132,414,733	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045
Income Tax Expense - Unclassified	-0	-0	0	-0	6110, 6115
Other Distribution Expenses	7,348,600	7,348,600	0	7,348,600	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 51
Unclassified Expenses	-0	-0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,538,849,309	1,538,849,309	0	1,500,268,259	Total

SUMMARY FINANCIAL INFORMATION

DISTRIBUTION ASSETS:

Land and Buildings	63,543,505	63,543,505	0	59,491,716
TS Primary Above 50	2,042,507	2,042,507	0	2,042,507
DS	160,292,889	160,292,889	0	154,675,548
Poles, Wires	2,206,311,296	2,206,311,296	0	2,150,197,704
Line Transformers	590,266,670	590,266,670	0	567,777,138
Services and Meters	180,213,917	180,213,917	0	173,828,546
General Plant	106,180,057	106,180,057	0	104,581,445
Equipment	152,782,819	152,782,819	0	144,591,620
IT Assets	176,005,434	176,005,434	0	161,559,897
CDM Assets	-0	-0	0	0
Other Distribution Assets	61,548,012	61,548,012	0	59,060,708
Contributions and Grants	-206,012,579	-206,012,579	0	-189,012,985
TOTAL DISTRIBUTION ASSETS	**3,493,174,526**	**3,493,174,526**	**0**	**3,388,793,845**

NET FIXED DISTRIBUTION ASSETS:

Total Distribution Assets (as above) - LESS:				
Accumulated Amortization	-1,870,181,709	-1,870,181,709	0	-1,804,382,078
NET FIXED DISTRIBUTION ASSETS	**1,622,992,817**	**1,622,992,817**	**0**	**1,584,411,767**

NET SALES REVENUE

Sales of Electricity	-2,352,085,634	-2,352,085,634	0	-2,352,085,634
Power Supply Expenses (Working Capital)	1,918,533,604	1,918,533,604	0	1,918,533,604
SALES OF ELECTRICITY NET OF COST OF POWER	-433,552,030	-433,552,030	0	-433,552,030

DISTRIBUTION REVENUE

Distribution Services Revenue	-0	-0	0	-0
Late Payment Charges	-4,080,000	-4,080,000	0	-4,080,000
Specific Service Charges	-6,783,697	-6,783,697	0	-6,783,697
Other Distribution Revenue	-7,181,593	-7,181,593	0	-7,181,593
TOTAL DISTRIBUTION REVENUE	**-18,045,290**	**-18,045,290**	**0**	**-18,045,290**

DISTRIBUTION EXPENSES (before PILS):

Operation (Working Capital)	50,904,714	50,904,714	0	50,904,714	
Maintenance (Working Capital)	40,848,274	40,848,274	0	40,848,274	
Billing and Collection (Working Capital)	26,252,492	26,252,492	0	26,252,492	
Community Relations (Working Capital)	3,349,933	3,349,933	0	3,349,933	
Community Relations - CDM (Working Capital)	3,569,855	3,569,855	0	3,569,855	
Administrative and General Expenses (Working Capital)	30,059,772	30,059,772	0	30,059,772	
Insurance Expense (Working Capital)	2,265,000	2,265,000	0	2,265,000	
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	7,000,000	
Advertising Expenses	-0	-0	0	-0	
Charitable Contributions	-0	-0	0	-0	
Amortization of Assets	132,414,733	132,414,733	0	132,414,733	
Other Distribution Expenses	7,348,600	7,348,600	0	7,348,600	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**304,013,373**	**304,013,373**	**0**	**304,013,373**	to pils
PILS AMOUNT					

WORKING CAPITAL CALCULATION

Cost of Power

Power Supply Expenses (Working Capital)	1,918,533,604	1,918,533,604	0	1,918,533,604
TOTAL COST OF POWER	1,918,533,604	1,918,533,604	0	1,918,533,604

Expenses

Operation (Working Capital)	50,904,714	50,904,714	0	50,904,714
Maintenance (Working Capital)	40,848,274	40,848,274	0	40,848,274
Billing and Collection (Working Capital)	26,252,492	26,252,492	0	26,252,492
Community Relations (Working Capital)	3,349,933	3,349,933	0	3,349,933
Community Relations - CDM (Working Capital)	3,569,855	3,569,855	0	3,569,855
Administrative and General Expenses (Working Capital)	30,059,772	30,059,772	0	30,059,772

Insurance Expense (Working Capital)	2,265,000	2,265,000	0	2,265,000
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	7,000,000
Advertising Expenses	0	0	0	-0
Charitable Contributions	0	0	0	-0
Other Distribution Expenses	7,348,600	7,348,600	0	7,348,600
TOTAL EXPENSES	171,598,640	171,598,640	0	171,598,640
TOTAL FOR WORKING CAPITAL CALCULATION	**2,090,132,244**	**2,090,132,244**	**0**	**2,090,132,244**

2008 TRIAL BALANCE

GROUPED INPUT FOR CALCULATIONS:
(Minimum Reporting Requirement)

Land and Buildings	67,731,017	67,731,017	0	0	65,637,261	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	7,542,507	7,542,507	0	0	4,792,507	1815
DS	179,487,101	179,487,101	0	0	169,889,995	1820
Poles, Wires	2,328,854,397	2,328,854,397	0	0	2,267,582,846	1830, 1835, 1840, 1845
Line Transformers	637,012,017	637,012,017	0	0	613,639,344	1850
Services and Meters	307,375,831	307,375,831	0	0	243,794,874	1855, 1860
General Plant	102,927,167	102,927,167	0	0	104,553,612	1908, 1910
Equipment	163,174,175	163,174,175	0	0	157,978,497	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	197,063,927	197,063,927	0	0	186,534,680	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	0	1565 (new account)
Other Distribution Assets	64,417,127	64,417,127	0	0	62,982,570	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-233,735,937	-233,735,937	0	0	-219,874,258	1995
Accumulated Amortization	-2,020,430,992	-2,020,430,992	0	0	-1,945,306,351	2105, 2120
Non-Distribution Asset	-0	-0	0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	698,000	698,000	0	0	698,000	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 151
Liability	-0	-0	0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 251
Equity	-0	-0	0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,426,992,623	-2,426,992,623	0	0	-2,426,992,623	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	0	-0	4080
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	4225
Specific Service Charges	-7,404,026	-7,404,026	0	0	-7,404,026	4235
Other Distribution Revenue	-6,660,133	-6,660,133	0	0	-6,660,133	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-7,270,970	-7,270,970	0	0	-7,270,970	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,922,552,889	1,922,552,889	0	0	1,922,552,889	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	59,627,953	59,627,953	0	0	59,627,953	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	46,548,093	46,548,093	0	0	46,548,093	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
Billing and Collection (Working Capital)	32,388,546	32,388,546	0	0	32,388,546	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,561,824	3,561,824	0	0	3,561,824	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	1,539,975	1,539,975	0	0	1,539,975	5415
Administrative and General Expenses (Working Capital)	35,065,948	35,065,948	0	0	35,065,948	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,720,000	2,720,000	0	0	2,720,000	5635, 6210
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	0	7,000,000	5335
Advertising Expenses	-0	-0	0	0	-0	5515, 5660
Charitable Contributions	-0	-0	0	0	-0	6205
Amortization of Assets	153,723,682	153,723,682	0	0	153,723,682	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045
Income Tax Expense - Unclassified	-0	-0	0	0	-0	6110, 6115
Other Distribution Expenses	7,571,070	7,571,070	0	0	7,571,070	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 51
Unclassified Expenses	-0	-0	0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,621,088,567	1,621,088,567	0	0	1,531,875,807	Total

SUMMARY FINANCIAL INFORMATION

DISTRIBUTION ASSETS:						
Land and Buildings	67,731,017	67,731,017	0	0	65,637,261	
TS Primary Above 50	7,542,507	7,542,507	0	0	4,792,507	
DS	179,487,101	179,487,101	0	0	169,889,995	
Poles, Wires	2,328,854,397	2,328,854,397	0	0	2,267,582,846	
Line Transformers	637,012,017	637,012,017	0	0	613,639,344	
Services and Meters	307,375,831	307,375,831	0	0	243,794,874	
General Plant	102,927,167	102,927,167	0	0	104,553,612	
Equipment	163,174,175	163,174,175	0	0	157,978,497	
IT Assets	197,063,927	197,063,927	0	0	186,534,680	
CDM Assets	-0	-0	0	0	0	
Other Distribution Assets	64,417,127	64,417,127	0	0	62,982,570	
Contributions and Grants	-233,735,937	-233,735,937	0	0	-219,874,258	
TOTAL DISTRIBUTION ASSETS	**3,821,849,330**	**3,821,849,330**	**0**	**0**	**3,657,511,928**	
NET FIXED DISTRIBUTION ASSETS:						
Total Distribution Assets (as above) - LESS:						
Accumulated Amortization	-2,020,430,992	-2,020,430,992	0	0	-1,945,306,351	
NET FIXED DISTRIBUTION ASSETS	**1,801,418,338**	**1,801,418,338**	**0**	**0**	**1,712,205,577**	
NET SALES REVENUE						
Sales of Electricity	-2,426,992,623	-2,426,992,623	0	0	-2,426,992,623	
Power Supply Expenses (Working Capital)	1,922,552,889	1,922,552,889	0	0	1,922,552,889	
SALES OF ELECTRICITY NET OF COST OF POWER	-504,439,734	-504,439,734	0	0	-504,439,734	
DISTRIBUTION REVENUE						
Distribution Services Revenue	-0	-0	0	0	-0	
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	
Specific Service Charges	-7,404,026	-7,404,026	0	0	-7,404,026	
Other Distribution Revenue	-6,660,133	-6,660,133	0	0	-6,660,133	
TOTAL DISTRIBUTION REVENUE	**-19,064,159**	**-19,064,159**	**0**	**0**	**-19,064,159**	
DISTRIBUTION EXPENSES (before PILS):						
Operation (Working Capital)	59,627,953	59,627,953	0	0	59,627,953	
Maintenance (Working Capital)	46,548,093	46,548,093	0	0	46,548,093	
Billing and Collection (Working Capital)	32,388,546	32,388,546	0	0	32,388,546	
Community Relations (Working Capital)	3,561,824	3,561,824	0	0	3,561,824	
Community Relations - CDM (Working Capital)	1,539,975	1,539,975	0	0	1,539,975	
Administrative and General Expenses (Working Capital)	35,065,948	35,065,948	0	0	35,065,948	
Insurance Expense (Working Capital)	2,720,000	2,720,000	0	0	2,720,000	
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	0	7,000,000	
Advertising Expenses	-0	-0	0	0	-0	
Charitable Contributions	-0	-0	0	0	-0	
Amortization of Assets	153,723,682	153,723,682	0	0	153,723,682	
Other Distribution Expenses	7,571,070	7,571,070	0	0	7,571,070	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**349,747,092**	**349,747,092**	**0**	**0**	**349,747,092**	to pils
PILS AMOUNT						
WORKING CAPITAL CALCULATION						
Cost of Power						
Power Supply Expenses (Working Capital)	1,922,552,889	1,922,552,889	0	0	1,922,552,889	
TOTAL COST OF POWER	1,922,552,889	1,922,552,889	0	0	1,922,552,889	
Expenses						
Operation (Working Capital)	59,627,953	59,627,953	0	0	59,627,953	
Maintenance (Working Capital)	46,548,093	46,548,093	0	0	46,548,093	
Billing and Collection (Working Capital)	32,388,546	32,388,546	0	0	32,388,546	

Community Relations (Working Capital)	3,561,824	3,561,824	0	0	3,561,824
Community Relations - CDM (Working Capital)	1,539,975	1,539,975	0	0	1,539,975
Administrative and General Expenses (Working Capital)	35,065,948	35,065,948	0	0	35,065,948
Insurance Expense (Working Capital)	2,720,000	2,720,000	0	0	2,720,000
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	0	7,000,000
Advertising Expenses	0	0	0	0	-0
Charitable Contributions	0	0	0	0	-0
Other Distribution Expenses	7,571,070	7,571,070	0	0	7,571,070
TOTAL EXPENSES	196,023,410	196,023,410	0	0	196,023,410
TOTAL FOR WORKING CAPITAL CALCULATION	**2,118,576,299**	**2,118,576,299**	**0**	**0**	**2,118,576,299**

2009 TRIAL BALANCE

GROUPED INPUT FOR CALCULATIONS:
(Minimum Reporting Requirement)

Land and Buildings	69,292,438	69,292,438	0	0	68,511,728	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	18,042,507	18,042,507	0	0	12,792,507	1815
DS	196,771,792	196,771,792	0	0	188,129,446	1820
Poles, Wires	2,462,576,213	2,462,576,213	0	0	2,395,715,305	1830, 1835, 1840, 1845
Line Transformers	678,687,164	678,687,164	0	0	657,849,590	1850
Services and Meters	365,405,102	365,405,102	0	0	336,390,466	1855, 1860
General Plant	108,794,710	108,794,710	0	0	105,860,938	1908, 1910
Equipment	172,618,310	172,618,310	0	0	167,896,243	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	235,661,750	235,661,750	0	0	216,362,838	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	0	1565 (new account)
Other Distribution Assets	66,182,120	66,182,120	0	0	65,299,624	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-253,659,242	-253,659,242	0	0	-243,697,589	1995
Accumulated Amortization	-2,181,317,301	-2,181,317,301	0	0	-2,100,874,147	2105, 2120
Non-Distribution Asset	-0	-0	0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	989,000	989,000	0	0	989,000	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 151
Liability	-0	-0	0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 251
Equity	-0	-0	0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,464,836,833	-2,464,836,833	0	0	-2,464,836,833	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	0	-0	4080
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	4225
Specific Service Charges	-7,532,201	-7,532,201	0	0	-7,532,201	4235
Other Distribution Revenue	-6,898,143	-6,898,143	0	0	-6,898,143	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-2,301,658	-2,301,658	0	0	-2,301,658	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,923,661,344	1,923,661,344	0	0	1,923,661,344	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	65,352,539	65,352,539	0	0	65,352,539	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	48,775,793	48,775,793	0	0	48,775,793	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
Billing and Collection (Working Capital)	32,819,695	32,819,695	0	0	32,819,695	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,655,723	3,655,723	0	0	3,655,723	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	1,618,945	1,618,945	0	0	1,618,945	5415
Administrative and General Expenses (Working Capital)	36,170,973	36,170,973	0	0	36,170,973	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,770,000	2,770,000	0	0	2,770,000	5635, 6210
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	5335
Advertising Expenses	-0	-0	0	0	-0	5515, 5660
Charitable Contributions	-0	-0	0	0	-0	6205
Amortization of Assets	160,886,305	160,886,305	0	0	160,886,305	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045
Income Tax Expense - Unclassified	-0	-0	0	0	-0	6110, 6115
Other Distribution Expenses	7,795,116	7,795,116	0	0	7,795,116	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 51
Unclassified Expenses	-0	-0	0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,744,482,159	1,744,482,159	0	0	1,675,663,547	Total

SUMMARY FINANCIAL INFORMATION

DISTRIBUTION ASSETS:						
Land and Buildings	69,292,438	69,292,438	0	0	68,511,728	
TS Primary Above 50	18,042,507	18,042,507	0	0	12,792,507	
DS	196,771,792	196,771,792	0	0	188,129,446	
Poles, Wires	2,462,576,213	2,462,576,213	0	0	2,395,715,305	
Line Transformers	678,687,164	678,687,164	0	0	657,849,590	
Services and Meters	365,405,102	365,405,102	0	0	336,390,466	
General Plant	108,794,710	108,794,710	0	0	105,860,938	
Equipment	172,618,310	172,618,310	0	0	167,896,243	
IT Assets	235,661,750	235,661,750	0	0	216,362,838	
CDM Assets	-0	-0	0	0	0	
Other Distribution Assets	66,182,120	66,182,120	0	0	65,299,624	
Contributions and Grants	-253,659,242	-253,659,242	0	0	-243,697,589	
TOTAL DISTRIBUTION ASSETS	**4,120,372,863**	**4,120,372,863**	**0**	**0**	**3,971,111,096**	
NET FIXED DISTRIBUTION ASSETS:						
Total Distribution Assets (as above) - LESS:						
Accumulated Amortization	-2,181,317,301	-2,181,317,301	0	0	-2,100,874,147	
NET FIXED DISTRIBUTION ASSETS	**1,939,055,561**	**1,939,055,561**	**0**	**0**	**1,870,236,950**	
NET SALES REVENUE						
Sales of Electricity	-2,464,836,833	-2,464,836,833	0	0	-2,464,836,833	
Power Supply Expenses (Working Capital)	1,923,661,344	1,923,661,344	0	0	1,923,661,344	
SALES OF ELECTRICITY NET OF COST OF POWER	-541,175,489	-541,175,489	0	0	-541,175,489	
DISTRIBUTION REVENUE						
Distribution Services Revenue	-0	-0	0	0	-0	
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	
Specific Service Charges	-7,532,201	-7,532,201	0	0	-7,532,201	
Other Distribution Revenue	-6,898,143	-6,898,143	0	0	-6,898,143	
TOTAL DISTRIBUTION REVENUE	**-19,430,344**	**-19,430,344**	**0**	**0**	**-19,430,344**	
DISTRIBUTION EXPENSES (before PILS):						
Operation (Working Capital)	65,352,539	65,352,539	0	0	65,352,539	
Maintenance (Working Capital)	48,775,793	48,775,793	0	0	48,775,793	
Billing and Collection (Working Capital)	32,819,695	32,819,695	0	0	32,819,695	
Community Relations (Working Capital)	3,655,723	3,655,723	0	0	3,655,723	
Community Relations - CDM (Working Capital)	1,618,945	1,618,945	0	0	1,618,945	
Administrative and General Expenses (Working Capital)	36,170,973	36,170,973	0	0	36,170,973	
Insurance Expense (Working Capital)	2,770,000	2,770,000	0	0	2,770,000	
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	
Advertising Expenses	-0	-0	0	0	-0	
Charitable Contributions	-0	-0	0	0	-0	
Amortization of Assets	160,886,305	160,886,305	0	0	160,886,305	
Other Distribution Expenses	7,795,116	7,795,116	0	0	7,795,116	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**367,345,089**	**367,345,089**	**0**	**0**	**367,345,089**	to pils
PILS AMOUNT						
WORKING CAPITAL CALCULATION						
Cost of Power						
Power Supply Expenses (Working Capital)	1,923,661,344	1,923,661,344	0	0	1,923,661,344	
TOTAL COST OF POWER	1,923,661,344	1,923,661,344	0	0	1,923,661,344	
Expenses						
Operation (Working Capital)	65,352,539	65,352,539	0	0	65,352,539	
Maintenance (Working Capital)	48,775,793	48,775,793	0	0	48,775,793	
Billing and Collection (Working Capital)	32,819,695	32,819,695	0	0	32,819,695	

Community Relations (Working Capital)	3,655,723	3,655,723	0	0	3,655,723
Community Relations - CDM (Working Capital)	1,618,945	1,618,945	0	0	1,618,945
Administrative and General Expenses (Working Capital)	36,170,973	36,170,973	0	0	36,170,973
Insurance Expense (Working Capital)	2,770,000	2,770,000	0	0	2,770,000
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000
Advertising Expenses	0	0	0	0	-0
Charitable Contributions	0	0	0	0	-0
Other Distribution Expenses	7,795,116	7,795,116	0	0	7,795,116
TOTAL EXPENSES	206,458,784	206,458,784	0	0	206,458,784
TOTAL FOR WORKING CAPITAL CALCULATION	**2,130,120,128**	**2,130,120,128**	**0**	**0**	**2,130,120,128**

2010 TRIAL BALANCE

GROUPED INPUT FOR CALCULATIONS:
(Minimum Reporting Requirement)

Land and Buildings	71,388,932	71,388,932	0	0	70,340,685	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	39,042,507	39,042,507	0	0	28,542,507	1815
DS	214,043,561	214,043,561	0	0	205,407,677	1820
Poles, Wires	2,606,093,730	2,606,093,730	0	0	2,534,334,971	1830, 1835, 1840, 1845
Line Transformers	723,416,319	723,416,319	0	0	701,051,741	1850
Services and Meters	406,278,004	406,278,004	0	0	385,841,553	1855, 1860
General Plant	117,445,819	117,445,819	0	0	113,120,264	1908, 1910
Equipment	183,466,845	183,466,845	0	0	178,042,578	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	261,120,000	261,120,000	0	0	248,390,875	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	0	1565 (new account)
Other Distribution Assets	67,895,668	67,895,668	0	0	67,038,894	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-273,582,548	-273,582,548	0	0	-263,620,895	1995
Accumulated Amortization	-2,355,047,277	-2,355,047,277	0	0	-2,268,182,289	2105, 2120
Non-Distribution Asset	-0	-0	0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	1,292,000	1,292,000	0	0	1,292,000	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 151
Liability	-0	-0	0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 251
Equity	-0	-0	0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,489,841,516	-2,489,841,516	0	0	-2,489,841,516	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	0	-0	4080
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	4225
Specific Service Charges	-7,699,376	-7,699,376	0	0	-7,699,376	4235
Other Distribution Revenue	-7,169,193	-7,169,193	0	0	-7,169,193	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-4,414,571	-4,414,571	0	0	-4,414,571	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,925,554,529	1,925,554,529	0	0	1,925,554,529	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	68,675,900	68,675,900	0	0	68,675,900	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	51,347,923	51,347,923	0	0	51,347,923	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
Billing and Collection (Working Capital)	33,212,388	33,212,388	0	0	33,212,388	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,716,148	3,716,148	0	0	3,716,148	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	1,736,566	1,736,566	0	0	1,736,566	5415
Administrative and General Expenses (Working Capital)	36,754,964	36,754,964	0	0	36,754,964	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,820,000	2,820,000	0	0	2,820,000	5635, 6210
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	5335
Advertising Expenses	-0	-0	0	0	-0	5515, 5660
Charitable Contributions	-0	-0	0	0	-0	6205
Amortization of Assets	174,420,111	174,420,111	0	0	174,420,111	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045
Income Tax Expense - Unclassified	-0	-0	0	0	-0	6110, 6115
Other Distribution Expenses	8,028,970	8,028,970	0	0	8,028,970	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 51
Unclassified Expenses	-0	-0	0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,862,496,401	1,862,496,401	0	0	1,801,243,402	Total

SUMMARY FINANCIAL INFORMATION

DISTRIBUTION ASSETS:						
Land and Buildings	71,388,932	71,388,932	0	0	70,340,685	
TS Primary Above 50	39,042,507	39,042,507	0	0	28,542,507	
DS	214,043,561	214,043,561	0	0	205,407,677	
Poles, Wires	2,606,093,730	2,606,093,730	0	0	2,534,334,971	
Line Transformers	723,416,319	723,416,319	0	0	701,051,741	
Services and Meters	406,278,004	406,278,004	0	0	385,841,553	
General Plant	117,445,819	117,445,819	0	0	113,120,264	
Equipment	183,466,845	183,466,845	0	0	178,042,578	
IT Assets	261,120,000	261,120,000	0	0	248,390,875	
CDM Assets	-0	-0	0	0	0	
Other Distribution Assets	67,895,668	67,895,668	0	0	67,038,894	
Contributions and Grants	-273,582,548	-273,582,548	0	0	-263,620,895	
TOTAL DISTRIBUTION ASSETS	**4,416,608,837**	**4,416,608,837**	**0**	**0**	**4,268,490,850**	
NET FIXED DISTRIBUTION ASSETS:						
Total Distribution Assets (as above) - LESS:						
Accumulated Amortization	-2,355,047,277	-2,355,047,277	0	0	-2,268,182,289	
NET FIXED DISTRIBUTION ASSETS	**2,061,561,560**	**2,061,561,560**	**0**	**0**	**2,000,308,561**	
NET SALES REVENUE						
Sales of Electricity	-2,489,841,516	-2,489,841,516	0	0	-2,489,841,516	
Power Supply Expenses (Working Capital)	1,925,554,529	1,925,554,529	0	0	1,925,554,529	
SALES OF ELECTRICITY NET OF COST OF POWER	-564,286,987	-564,286,987	0	0	-564,286,987	
DISTRIBUTION REVENUE						
Distribution Services Revenue	-0	-0	0	0	-0	
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	
Specific Service Charges	-7,699,376	-7,699,376	0	0	-7,699,376	
Other Distribution Revenue	-7,169,193	-7,169,193	0	0	-7,169,193	
TOTAL DISTRIBUTION REVENUE	**-19,868,569**	**-19,868,569**	**0**	**0**	**-19,868,569**	
DISTRIBUTION EXPENSES (before PILS):						
Operation (Working Capital)	68,675,900	68,675,900	0	0	68,675,900	
Maintenance (Working Capital)	51,347,923	51,347,923	0	0	51,347,923	
Billing and Collection (Working Capital)	33,212,388	33,212,388	0	0	33,212,388	
Community Relations (Working Capital)	3,716,148	3,716,148	0	0	3,716,148	
Community Relations - CDM (Working Capital)	1,736,566	1,736,566	0	0	1,736,566	
Administrative and General Expenses (Working Capital)	36,754,964	36,754,964	0	0	36,754,964	
Insurance Expense (Working Capital)	2,820,000	2,820,000	0	0	2,820,000	
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	
Advertising Expenses	-0	-0	0	0	-0	
Charitable Contributions	-0	-0	0	0	-0	
Amortization of Assets	174,420,111	174,420,111	0	0	174,420,111	
Other Distribution Expenses	8,028,970	8,028,970	0	0	8,028,970	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**388,212,969**	**388,212,969**	**0**	**0**	**388,212,969**	to pils
PILS AMOUNT						
WORKING CAPITAL CALCULATION						
Cost of Power						
Power Supply Expenses (Working Capital)	1,925,554,529	1,925,554,529	0	0	1,925,554,529	
TOTAL COST OF POWER	1,925,554,529	1,925,554,529	0	0	1,925,554,529	
Expenses						
Operation (Working Capital)	68,675,900	68,675,900	0	0	68,675,900	
Maintenance (Working Capital)	51,347,923	51,347,923	0	0	51,347,923	
Billing and Collection (Working Capital)	33,212,388	33,212,388	0	0	33,212,388	

Community Relations (Working Capital)	3,716,148	3,716,148	0	0	3,716,148
Community Relations - CDM (Working Capital)	1,736,566	1,736,566	0	0	1,736,566
Administrative and General Expenses (Working Capital)	36,754,964	36,754,964	0	0	36,754,964
Insurance Expense (Working Capital)	2,820,000	2,820,000	0	0	2,820,000
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000
Advertising Expenses	0	0	0	0	-0
Charitable Contributions	0	0	0	0	-0
Other Distribution Expenses	8,028,970	8,028,970	0	0	8,028,970
TOTAL EXPENSES	213,792,858	213,792,858	0	0	213,792,858
TOTAL FOR WORKING CAPITAL CALCULATION	**2,139,347,387**	**2,139,347,387**	**0**	**0**	**2,139,347,387**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I4 Break Out Worksheet

Ontario

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Handbook for detailed instructions*****

Enter Net Fixed Assets from approved EDR, Sheet 2-1, cell E12	$1,712,205,577

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$15,443,114		-	15,443,114	$0	$0	$ (2,523,488)	$ -	12,919,626	$1,498,023			
1805	Land	$2,140,539		($2,140,539)	-									
1805-1	Land Station >50 kV		21.23%	$454,416	454,416	$0	$0	$ -	$ -	454,416				
1805-2	Land Station <50 kV		78.77%	$1,686,123	1,686,123	$0	$0	$ -	$ -	1,686,123				
1806	Land Rights	$1,430,219		($1,430,219)	-									
1806-1	Land Rights Station >50 kV			$0	-	$0	$0	$ -	$ -	-		$0	$0	
1806-2	Land Rights Station <50 kV		100.00%	$1,430,219	1,430,219	$0	$0	$ -	$ (212,548)	1,217,671		28,604	$0	
1808	Buildings and Fixtures	$47,231,474		($47,231,474)	-									
1808-1	Buildings and Fixtures > 50 kV		3.13%	$1,480,358	1,480,358	$0	$0	$ (499,244)	$ -	981,114	$29,423			
1808-2	Buildings and Fixtures < 50 kV		96.87%	$45,751,116	45,751,116	$0	$0	$ (15,336,338)	$ -	30,414,778	$909,337			
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV			$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$13,181,208		$0	13,181,208			($2,829,051)	$ (374,993)	9,977,164	$209,717	$0	$191,700	
1820	Distribution Station Equipment - Normally Primary below 50 kV	$160,020,936		($160,020,936)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-			$ -		-	$0			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		92.02%	$147,255,222	147,255,222			($74,604,025)		72,651,197	$3,881,489			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		7.98%	$12,765,714	12,765,714			$ (479,132)		12,286,582	$425,481			
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV			$0	-					-				
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$318,006,276		($318,006,276)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-	$0			
1830-4	Poles, Towers and Fixtures - Primary		52.98%	$168,479,725	168,479,725	($5,172,777)	$1,057,756	$ (74,103,283)		90,261,421	$6,159,699			
1830-5	Poles, Towers and Fixtures - Secondary		47.02%	$149,526,551	149,526,551	$0	$0	$ (65,767,014)		83,759,537	$5,650,396			
1835	Overhead Conductors and Devices	$234,524,211		($234,524,211)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1835-4	Overhead Conductors and Devices - Primary		52.98%	$124,250,927	124,250,927	($4,998,228)	$1,015,698	($80,839,270)		39,429,127	$4,468,209			
1835-5	Overhead Conductors and Devices - Secondary		47.02%	$110,273,284	110,273,284	$0	$0	($71,745,233)		38,528,051	$4,142,994			
1840	Underground Conduit	$972,135,481		($972,135,481)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1840-4	Underground Conduit - Primary		73.74%	$716,852,704	716,852,704	($29,937,354)	$4,132,088	($349,571,990)		341,475,448	$25,461,719			
1840-5	Underground Conduit - Secondary		26.26%	$255,282,777	255,282,777	($44,906,032)	$6,198,132	($124,488,208)		92,086,670	$7,978,128			

1845	Underground Conductors and Devices	$428,592,762		($428,592,762)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1845-4	Underground Conductors and Devices - Primary		73.74%	$316,044,302	316,044,302	($35,240,045)	$5,967,607	($153,456,452)		133,315,412	$10,821,565			
1845-5	Underground Conductors and Devices - Secondary		26.26%	$112,548,459	112,548,459	($11,746,682)	$1,989,202	($54,648,311)		48,142,669	$3,885,749			
1850	Line Transformers	$613,420,551		$0	613,420,551	($82,833,694)	$9,315,694	($300,902,650)		238,999,901	$18,815,588			
1855	Services	$316,671,669		$0	316,671,669	($2,989,970)	$382,127	($162,072,047)		151,991,779	$11,574,589			
1860	Meters	$196,585,247		$0	196,585,247	($2,049,477)	$491,028	($92,274,863)		102,751,935	$15,082,855			
	Total	**$3,319,383,687**		**$0.0**	**$3,319,383,687**	**($219,874,258)**	**$30,549,331**	**($1,626,140,598)**	**($587,541)**	**1,503,330,620**	**$120,994,961**	**$28,604**	**$191,700**	**$0**
	SUB TOTAL from I3	**$3,303,940,573**												

General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1905	Land	$7,512,419			7,512,419			$ -		$ 7,512,419				
1906	Land Rights	$8,739,351			8,739,351			$ -	$ (2,104,231)	$ 6,635,120		$174,787	$0	
1908	Buildings and Fixtures	$99,737,632			99,737,632			$ (30,903,334)		$ 68,834,298	$2,352,037			
1910	Leasehold Improvements	$3,872,267			3,872,267			$ -	$ (2,702,274)	$ 1,169,993		$325,874	$0	
1915	Office Furniture and Equipment	$21,072,675			21,072,675			$ (18,242,930)		$ 2,829,745	727,474			
1920	Computer Equipment - Hardware	$47,131,683			47,131,683			$ (38,982,514)		$ 8,149,169	3,205,553			
1925	Computer Software	$137,437,207			137,437,207			$ (95,041,935)		$ 42,395,272	14,468,034			
1930	Transportation Equipment	$69,604,585			69,604,585			$ (49,780,353)		$ 19,824,232	4,352,125			
1935	Stores Equipment	$5,506,283			5,506,283			$ (5,456,647)		$ 49,637	7,851			
1940	Tools, Shop and Garage Equipment	$29,947,922			29,947,922			$ (21,741,205)		$ 8,206,717	1,374,300			
1945	Measurement and Testing Equipment	$4,450,502			4,450,502			$ (4,028,728)		$ 421,775	94,355			
1950	Power Operated Equipment	$0			-					$ -				
1955	Communication Equipment	$26,228,889			26,228,889			$ (22,354,831)		$ 3,874,058	1,167,482			
1960	Miscellaneous Equipment	$104,582			104,582			$ (104,582)		-$ 0	-			
1970	Load Management Controls - Customer Premises	$6,174,207			6,174,207			$ (4,114,792)		$ 2,059,415	293,937			
1975	Load Management Controls - Utility Premises	$554,382			554,382			$ (525,613)		$ 28,769	41,365			
1980	System Supervisory Equipment	$46,563,178			46,563,178			$ (30,486,551)		$ 16,076,627	2,084,497			
1990	Other Tangible Property	$0			-					$ -				
2005	Property Under Capital Leases	$988,548			988,548			$ (571,810)		$ 416,738	243,333			
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$515,626,311		$0	$515,626,311	$0	$0	($322,335,822)	($4,806,505)	$188,483,984	$30,412,343	$500,661	$0	$0
	SUB TOTAL from I3	$515,626,311												
	I3 Directly Allocatec	$20,390,973												
	Grand Total	$3,855,400,971		$0	$3,835,009,998	($219,874,258)	$30,549,331	($1,948,476,420)	($5,394,046)	$1,691,814,605	$151,407,304	$529,265	$191,700	$0

To be Prorated

1995	Contributed Capital - 1995	($219,874,258)		$219,874,258	Balanced			
2105	Accumulated Depreciation - 2105	($1,917,927,089.00)				$1,917,927,089.00	Balanced	
2120	Accumulated Depreciation - 2120	($5,394,046.00)					$5,394,046.00	Balanced
	Total	**($2,143,195,393)**						
	Net Assets	**$1,712,205,578**	**Net Fixed Assets Match EDR**					

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$151,407,304	($151,407,304)	Balanced				
5710	Amortization of Limited Term Electric Plant	$529,265		($529,265)	Balanced			
5715	Amortization of Intangibles and Other Electric Plant	$191,700			($191,700)	Balanced		
5720	Amortization of Electric Plant Acquisition Adjustments	$0				$0	Balanced	
	Total Amortization Expense	**$152,128,269**						

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I4 Break Out Worksheet

Ontario

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Handbook for detailed instructions*****

Enter Net Fixed Assets from approved EDR, Sheet 3-1, cell F12	$1,870,236,950

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$15,880,934		-	15,880,934	$0	$0	$ (4,065,293)	$ -	11,815,641	$1,585,587			
1805	Land	$2,140,539		($2,140,539)	-									
1805-1	Land Station >50 kV		21.23%	$454,416	454,416	$0	$0	$ -	$ -	454,416				
1805-2	Land Station <50 kV		78.77%	$1,686,123	1,686,123	$0	$0	$ -	$ -	1,686,123				
1806	Land Rights	$1,485,219		($1,485,219)	-									
1806-1	Land Rights Station >50 kV			$0	-	$0	$0	$ -	$ -	-		$0	$0	
1806-2	Land Rights Station <50 kV		100.00%	$1,485,219	1,485,219	$0	$0	$ -	$ (241,703)	1,243,517		$29,704	$0	
1808	Buildings and Fixtures	$50,428,304		($50,428,304)	-									
1808-1	Buildings and Fixtures > 50 kV		2.94%	$1,480,358	1,480,358	$0	$0	($536,253)	$ -	944,105	$29,412			
1808-2	Buildings and Fixtures < 50 KV		97.06%	$48,947,946	48,947,946	$0	$0	$ (16,269,659)	$ -	32,678,287	$972,490			
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV			$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$21,181,208		$0	21,181,208			($3,038,768)	$ (726,693)	17,415,747	$209,717	$0	$511,700	
1820	Distribution Station Equipment - Normally Primary below 50 kV	$178,260,387		($178,260,387)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-			$ -		-	$0			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		88.07%	$156,994,674	156,994,674			($78,603,869)		78,390,805	$4,118,198			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		11.93%	$21,265,714	21,265,714			$ (1,046,265)		20,219,449	$708,786			
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV			$0	-					-				
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$330,505,297		($330,505,297)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-	$0			
1830-4	Poles, Towers and Fixtures - Primary		52.98%	$175,101,706	175,101,706	($5,369,372)	$1,268,599	$ (80,566,350)		90,434,583	$6,344,749			
1830-5	Poles, Towers and Fixtures - Secondary		47.02%	$155,403,590	155,403,590	$0	$0	$ (71,503,016)		83,900,574	$5,821,609			
1835	Overhead Conductors and Devices	$242,865,350		($242,865,350)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1835-4	Overhead Conductors and Devices - Primary		52.98%	$128,670,062	128,670,062	($5,207,930)	$1,219,821	($85,544,691)		39,137,262	$4,534,387			
1835-5	Overhead Conductors and Devices - Secondary		47.02%	$114,195,288	114,195,288	$0	$0	($75,921,317)		38,273,971	$4,209,173			
1840	Underground Conduit	$1,027,277,710		($1,027,277,710)	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-	$0	$0	$0		-	$0			

1840-4	Underground Conduit - Primary		73.74%	$757,514,583	757,514,583	($32,074,014)	$5,095,125	($376,526,169)		354,009,525	$26,574,366			
1840-5	Underground Conduit - Secondary		26.26%	$269,763,127	269,763,127	($48,111,021)	$7,642,687	($134,087,025)		95,207,768	$8,276,596			
1845	Underground Conductors and Devices	$477,597,685		($477,597,685)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1845-4	Underground Conductors and Devices - Primary		73.74%	$352,180,533	352,180,533	($38,111,298)	$7,383,423	($166,299,446)		155,153,212	$12,031,214			
1845-5	Underground Conductors and Devices - Secondary		26.26%	$125,417,152	125,417,152	($12,703,766)	$2,461,141	($59,221,908)		55,952,620	$4,319,142			
1850	Line Transformers	$657,630,797		$0	657,630,797	($96,975,723)	$12,714,489	($323,623,629)		249,745,935	$19,828,777			
1855	Services	$324,780,992		$0	324,780,992	($3,094,989)	$503,826	($173,928,422)		148,261,407	$11,894,762			
1860	Meters	$281,071,517		$0	281,071,517	($2,049,476)	$573,007	($106,639,986)		172,955,062	$13,483,431			
	Total	**$3,611,105,939**		**$0.0**	**$3,611,105,939**	**($243,697,589)**	**$38,862,117**	**($1,757,422,065)**	**($968,396)**	**1,647,880,007**	**$124,942,396**	**$29,704**	**$511,700**	**$0**
	SUB TOTAL from I3	**$3,611,105,939**												

General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1905	Land	$7,135,056			7,135,056			$ -		$ 7,135,056				
1906	Land Rights	$8,739,351			8,739,351			$ -	$ (2,279,018)	$ 6,460,333		$174,787	$0	
1908	Buildings and Fixtures	$100,944,958			100,944,958			$ (31,417,268)		$ 69,527,691	$2,150,230			
1910	Leasehold Improvements	$3,972,267			3,972,267			$ -	$ (3,038,148)	$ 934,119		$345,873	$0	
1915	Office Furniture and Equipment	$21,343,525			21,343,525			$ (18,928,059)		$ 2,415,466	642,785			
1920	Computer Equipment - Hardware	$52,752,269			52,752,269			$ (42,701,044)		$ 10,051,225	4,231,507			
1925	Computer Software	$161,206,959			161,206,959			$ (110,413,849)		$ 50,793,110	16,275,794			
1930	Transportation Equipment	$77,823,269			77,823,269			$ (54,348,215)		$ 23,475,055	4,773,599			
1935	Stores Equipment	$5,506,283			5,506,283			$ (5,464,460)		$ 41,823	7,777			
1940	Tools, Shop and Garage Equipment	$30,347,922			30,347,922			$ (23,016,421)		$ 7,331,501	1,176,132			
1945	Measurement and Testing Equipment	$4,450,502			4,450,502			$ (4,118,387)		$ 332,116	84,963			
1950	Power Operated Equipment	$0			-					$ -				
1955	Communication Equipment	$27,257,100			27,257,100			$ (23,568,800)		$ 3,688,301	1,260,455			
1960	Miscellaneous Equipment	$104,582			104,582			$ (104,582)		-$ 0	-			
1970	Load Management Controls - Customer Premises	$6,267,988			6,267,988			$ (4,386,268)		$ 1,881,720	249,016			
1975	Load Management Controls - Utility Premises	$554,382			554,382			$ (550,339)		$ 4,043	8,087			
1980	System Supervisory Equipment	$48,786,452			48,786,452			$ (32,574,748)		$ 16,211,704	2,091,897			
1990	Other Tangible Property	$0			-					$ -				
2005	Property Under Capital Leases	$988,548			988,548			$ (805,003)		$ 183,545	233,052			
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$558,181,412		$0	$558,181,412	$0	$0	($352,397,440)	($5,317,166)	$200,466,807	$33,185,294	$520,660	$0	$0
	SUB TOTAL from I3	$558,181,412												
	I3 Directly Allocated	$21,890,138												
	Grand Total	$4,191,177,489		$0	$4,169,287,351	($243,697,589)	$38,862,117	($2,109,819,504)	($6,285,561)	$1,848,346,813	$158,127,690	$550,364	$511,700	$0

To be Prorated

1995	Contributed Capital - 1995	($243,697,589)		$243,697,589	Balanced				
2105	Accumulated Depreciation - 2105	($2,070,957,388)				$2,070,957,388	Balanced		
2120	Accumulated Depreciation - 2120	($6,285,561)					$6,285,561	Balanced	
	Total	**($2,320,940,538)**							
	Net Assets	**$1,870,236,951**	**Net Fixed Assets Match EDR**						

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$158,127,690	($158,127,690)	Balanced			
5710	Amortization of Limited Term Electric Plant	$550,364		($550,364)	Balanced		
5715	Amortization of Intangibles and Other Electric Plant	$511,700			($511,700)	Balanced	
5720	Amortization of Electric Plant Acquisition Adjustments	$0				$0	Balanced
	Total Amortization Expense	**$159,189,754**					

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I4 Break Out Worksheet

Ontario

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Handbook for detailed instructions*

Enter Net Fixed Assets from approved EDR, Sheet 3-1, cell F12	$2,000,308,561

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$16,249,461		-	16,249,461	$0	$0	$ (5,687,733)	$ -	10,561,728	$1,659,293			
1805	Land	$2,140,539		($2,140,539)	-									
1805-1	Land Station >50 kV		21.23%	$454,416	454,416	$0	$0	$ -	$ -	454,416				
1805-2	Land Station <50 kV		78.77%	$1,686,124	1,686,124	$0	$0	$ -	$ -	1,686,124				
1806	Land Rights	$1,485,219		($1,485,219)	-									
1806-1	Land Rights Station >50 kV			$0	-	$0	$0	$ -	$ -	-		$0	$0	
1806-2	Land Rights Station <50 kV		100.00%	$1,485,219	1,485,219	$0	$0	$ -	$ (271,407)	1,213,812		$29,704	$0	
1808	Buildings and Fixtures	$52,257,261		($52,257,261)	-									
1808-1	Buildings and Fixtures > 50 kV		2.83%	$1,480,358	1,480,358	$0	$0	($573,262)	$ -	907,096	$29,374			
1808-2	Buildings and Fixtures < 50 KV		97.17%	$50,776,903	50,776,903	$0	$0	$ (17,252,057)	$ -	33,524,846	$1,007,540			
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV			$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$36,931,208		$0	36,931,208			($3,248,486)	$ (1,553,394)	32,129,329	$209,717	$0	$1,141,700	
1820	Distribution Station Equipment - Normally Primary below 50 kV	$195,538,618		($195,538,618)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-			$ -		-	$0			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		86.06%	$168,272,904	168,272,904			($82,861,415)		85,411,489	$4,396,897			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		13.94%	$27,265,714	27,265,714			$ (1,855,042)		25,410,672	$908,766			
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV			$0	-					-				
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$343,688,261		($343,688,261)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-	$0			
1830-4	Poles, Towers and Fixtures - Primary		52.98%	$182,086,041	182,086,041	($5,565,646)	$1,487,299	$ (87,232,693)		90,775,001	$6,550,534			
1830-5	Poles, Towers and Fixtures - Secondary		47.02%	$161,602,220	161,602,220	$0	$0	$ (77,419,426)		84,182,794	$6,011,212			
1835	Overhead Conductors and Devices	$251,416,900		($251,416,900)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1835-4	Overhead Conductors and Devices - Primary		52.98%	$133,200,674	133,200,674	($5,417,291)	$1,432,325	($90,301,897)		38,913,812	$4,555,016			
1835-5	Overhead Conductors and Devices - Secondary		47.02%	$118,216,226	118,216,226	$0	$0	($80,143,359)		38,072,867	$4,234,913			
1840	Underground Conduit	$1,088,333,243		($1,088,333,243)	-									

1840-3	Underground Conduit - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1840-4	Underground Conduit - Primary		73.74%	$802,536,933	802,536,933	($34,242,586)	$6,141,507	($404,962,348)		369,473,506	$28,263,682			
1840-5	Underground Conduit - Secondary		26.26%	$285,796,310	285,796,310	($51,363,878)	$9,212,260	($144,213,605)		99,431,086	$8,778,965			
1845	Underground Conductors and Devices	$529,972,281		($529,972,281)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-	$0	$0	$0		-	$0			
1845-4	Underground Conductors and Devices - Primary		73.74%	$390,801,560	390,801,560	($40,866,722)	$8,908,167	($180,563,451)		178,279,554	$13,445,614			
1845-5	Underground Conductors and Devices - Secondary		26.26%	$139,170,721	139,170,721	($13,622,241)	$2,969,389	($64,301,549)		64,216,320	$4,825,343			
1850	Line Transformers	$700,832,948		$0	700,832,948	($107,293,851)	$16,602,488	($347,860,333)		262,281,252	$20,868,635			
1855	Services	$333,287,980		$0	333,287,980	($3,199,205)	$629,709	($186,117,123)		144,601,362	$12,230,873			
1860	Meters	$322,015,614		$0	322,015,614	($2,049,477)	$654,986	($121,421,455)		199,199,669	$15,915,540			
	Total	**$3,874,149,534**		**$0.0**	**$3,874,149,534**	**($263,620,895)**	**$48,038,129**	**($1,896,015,234)**	**($1,824,801)**	**1,760,726,733**	**$133,891,914**	**$29,704**	**$1,141,700**	**$0**
	SUB TOTAL from I3	**$3,874,149,534**												

General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1905	Land	$7,135,056			7,135,056			$ -		$ 7,135,056				
1906	Land Rights	$8,739,351			8,739,351			$ -	$ (2,453,806)	$ 6,285,546		$174,787	$0	
1908	Buildings and Fixtures	$108,104,285			108,104,285			$ (33,173,948)		$ 74,930,337	$2,053,268			
1910	Leasehold Improvements	$4,072,267			4,072,267			$ -	$ (3,394,020)	$ 678,246		$365,873	$0	
1915	Office Furniture and Equipment	$22,268,525			22,268,525			$ (19,507,322)		$ 2,761,203	515,741			
1920	Computer Equipment - Hardware	$58,254,786			58,254,786			$ (47,383,294)		$ 10,871,492	5,132,994			
1925	Computer Software	$187,363,949			187,363,949			$ (128,023,711)		$ 59,340,239	18,943,929			
1930	Transportation Equipment	$85,786,119			85,786,119			$ (59,412,446)		$ 26,373,673	5,344,865			
1935	Stores Equipment	$5,506,283			5,506,283			$ (5,472,220)		$ 34,064	7,742			
1940	Tools, Shop and Garage Equipment	$30,797,922			30,797,922			$ (24,194,869)		$ 6,603,053	1,180,764			
1945	Measurement and Testing Equipment	$4,450,502			4,450,502			$ (4,202,543)		$ 247,960	83,349			
1950	Power Operated Equipment	$0			-					$ -				
1955	Communication Equipment	$28,065,585			28,065,585			$ (24,873,805)		$ 3,191,781	1,349,555			
1960	Miscellaneous Equipment	$104,582			104,582			$ (104,582)		-$ 0	-			
1970	Load Management Controls - Customer Premises	$6,267,989			6,267,989			$ (4,628,690)		$ 1,639,299	235,828			
1975	Load Management Controls - Utility Premises	$554,382			554,382			$ (554,382)		-$ 0	-			
1980	System Supervisory Equipment	$50,525,722			50,525,722			$ (34,669,165)		$ 15,856,557	2,096,937			
1990	Other Tangible Property	$0			-					$ -				
2005	Property Under Capital Leases	$988,548			988,548			$ (935,746)		$ 52,802	38,433			
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$608,985,853		$0	$608,985,853	$0	$0	($387,136,721)	($5,847,826)	$216,001,306	$36,983,405	$540,660	$0	$0
	SUB TOTAL from I3	$608,985,853												
	I3 Directly Allocated	$23,580,522												
	Grand Total	$4,506,715,909		$0	$4,483,135,387	($263,620,895)	$48,038,129	($2,283,151,955)	($7,672,626)	$1,976,728,039	$170,875,319	$570,364	$1,141,700	$0

To be Prorated

1995	Contributed Capital - 1995	($263,620,895.00)		$263,620,895.00	**Balanced**			
2105	Accumulated Depreciation - 2105	($2,235,113,827)				$2,235,113,827	**Balanced**	
2120	Accumulated Depreciation - 2120	($7,672,626)					$7,672,626.40	**Balanced**
	Total	**($2,506,407,348)**						
	Net Assets	**$2,000,308,561**	**Net Fixed Assets Match EDR**					

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$170,875,319	($170,875,319)	**Balanced**		
5710	Amortization of Limited Term Electric Plant	$570,364		($570,364)	**Balanced**	
5715	Amortization of Intangibles and Other Electric Plant	$1,141,700			($1,141,700)	**Balanced**
5720	Amortization of Electric Plant Acquisition Adjustments	$0				$0 **Balanced**
	Total Amortization Expense	**$172,587,383**				

Ontario

2008 COST ALLOCATION STUDY

Toronto Hydro-Electric System Limited

EB-2007-0680

Sheet I5 Miscellaneous Data Worksheet

kMs of Roads in Service Area Where Distribution Lines Exist	5365
Deemed Equity Component of Rate Base (%)	37.5%

	1	2	3	4	5	6	7	9
	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Instructions (Cont'd):								
Step 3: 2007 Approved Rates	12.00	16.07	25.58	25.82	717.42	2758.30	0.26	1.99
Step 4: Insert 2007 Smart Meter Adder	0.68	0.68	0.68	0.68	0.68	0.68		

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2009 COST ALLOCATION STUDY

Toronto Hydro-Electric System Limited

EB-2007-0680

Sheet I5 Miscellaneous Data Worksheet

kMs of Roads in Service Area Where Distribution Lines Exist	5365
Deemed Equity Component of Rate Base (%)	40%

Instructions (Cont'd):

Step 3: 2007 Approved Rates

Step 4: Insert 2007 Smart Meter Adder

1	2	3	4	5	6	7	9
Residential	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
12.00	16.07	25.58	25.82	717.42	2758.30	0.26	1.99
0.68	0.68	0.68	0.68	0.68	0.68		

2010 COST ALLOCATION STUDY

Toronto Hydro-Electric System Limited

EB-2007-0680

Sheet I5 Miscellaneous Data Worksheet

kMs of Roads in Service Area Where Distribution Lines Exist	5365
Deemed Equity Component of Rate Base (%)	40%

Instructions (Cont'd):

Step 3: 2007 Approved Rates

Step 4: Insert 2007 Smart Meter Adder

1	2	3	4	5	6	7	9
Residential	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
12.00	16.07	25.58	25.82	717.42	2758.30	0.26	1.99
0.68	0.68	0.68	0.68	0.68	0.68		

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I6 Customer Data Worksheet

Ontario

Total kWhs	25,769,537,891

Total kVAs	43,425,682

Total Approved Distribution Revenue ($)	$510,276,035

	ID	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data											
Forecast kWh	CEN	25,769,537,891	5,498,828,031	2,575,446,564	1,364,599,404	8,485,862,596	5,086,725,921	2,589,940,302	110,184,165	-	57,950,907
Forecast kVA	CDEM	43,425,682			3,796,584	22,141,961	11,740,732	5,428,878	317,526		
Forecast kVA included in CDEM, from customers with line transformer allowance		19,309,571			626,441	4,638,320	8,879,999	5,164,811			
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-									
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	25,541,402,712	5,498,828,031	2,575,446,564	1,364,599,404	8,485,862,596	5,086,725,921	2,361,805,123	110,184,165	-	57,950,907
Distribution Rev from EDR	CREV	510,276,035	199,876,295	69,517,532	22,458,325	129,952,515	61,290,349	23,987,572	1,884,920		1,308,527
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	7,000,000	$3,933,327	$1,881,934	$801,603	$131,541	$251,595	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	5,000,000	$2,740,702	$1,101,152	$734,944	$192,582	$197,409	$33,211	$0		$0
Weighting Factor - Services			1.0	2.0	10.0	10.0	10.0	30.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	7.0	7.0	15.0	1.0	0.1	5.0
Number of Bills	CNB	4,652,454	3,702,942	803,208	25,620	113,412	6,336	588	204		144
Number of Connections (Unmetered)	CCON	106,533							88,812		17,721
Total Number of Customer excluding connections	CCA	696,267	617,157	66,934	2,135	9,451	528	49	1		12
Bulk Customer Base	CCB	-	-	-	-	-	-	-	-		-
Primary Customer Base	CCP	696,267	617,157	66,934	2,135	9,451	528	49	1		12
Line Transformer Customer Base	CCLT	693,490	617,157	66,934	1,783	7,471	129	3	1		12
Secondary Customer Base	CCS	686,893	617,157	66,934	535	2,241	13	0	1	-	12
Weighted - Services	CWCS	885,458	617,157	133,868	5,348	22,414	129	10	88,812	-	17,721
Weighted Meter -Capital	CWMC	152,738,298	103,204,097	12,695,138	3,595,340	28,286,843	4,466,880	490,000	-	-	-
Weighted Meter Reading	CWMR	5,841,668	4,174,194	1,614,958	52,516	-	-	-	-	-	-
Weighted Bills	CWNB	6,336,678	3,702,942	1,606,416	179,340	793,884	44,352	8,820	204	-	720

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	7,000,000	3,933,327	1,881,934	801,603	131,541	251,595	-	-	-	-
Sheet ADJ5 rows 26 - 32, column F	7,000,000	3,933,327	1,881,934	801,603	131,541	251,595	-	-	-	-
Sheet ADJ5 rows 26 - 32, column G	7,000,000	3,933,327	1,881,934	801,603	131,541	251,595	-	-	-	-
Three-year average	**7,000,000**	**3,933,327**	**1,881,934**	**801,603**	**131,541**	**251,595**	**-**	**-**	**-**	**-**

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I6 Customer Data Worksheet

Ontario

Total kWhs	25,766,749,611

Total kVAs	43,229,017

Total Approved Distribution Revenue ($)	$545,873,066

			1	2	3	4	5	6	7	9
	ID	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Billing Data										
Forecast kWh	CEN	25,766,749,611	5,613,078,765	2,573,543,699	662,344,787	9,060,309,140	5,092,879,460	2,596,088,397	110,403,450	58,101,913
Forecast kVA	CDEM	43,229,017			1,834,032	23,866,504	11,769,012	5,441,942	317,526	
kW, included in CDEM, from customers with line transformer allowance		19,270,593			300,593	4,891,347	8,901,444	5,177,210		
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	25,538,614,432	5,613,078,765	2,573,543,699	662,344,787	9,060,309,140	5,092,879,460	2,367,953,218	110,403,450	58,101,913
Distribution Rev from EDR	CREV	545,873,066	226,304,371	74,315,256	11,229,728	141,189,575	61,791,541	24,911,702	4,316,459	1,814,433
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$7,500,000	$4,214,279	$2,016,358	$858,861	$140,936	$269,566	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$5,000,000	$2,740,702	$1,101,152	$734,943	$192,583	$197,409	$33,211	$0	$0
Weighting Factor - Services			1.0	2.0	10.0	10.0	10.0	30.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	7.0	7.0	15.0	1.0	5.0
Number of Bills	CNB	4,816,566	3,867,402	802,536	12,780	126,480	6,432	588	204	144
Number of Connections (Unmetered)	CCON	101,380							88,812	12,568
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	883,508	644,567	66,878	1,065	10,540	536	49	159,861	12
Bulk Customer Base	CCB	-	-	-	-	-	-	-	-	-

Primary Customer Base	**CCP**	883,508	644,567	66,878	1,065	10,540	536	49	159,861	12
Line Transformer Customer Base	**CCLT**	880,722	644,567	66,878	890	8,380	131	3	159,861	12
Secondary Customer Base	**CCS**	874,112	644,567	66,878	267	2,514	13	0	159,861	12
Weighted - Services	**CWCS**	907,654	644,567	133,756	2,671	25,140	131	10	88,812	12,568
Weighted Meter -Capital	**CWMC**	165,158,214	110,685,944	16,177,650	1,790,427	31,479,634	4,534,560	490,000	-	-
Weighted Meter Reading	**CWMR**	5,979,104	4,338,654	1,613,614	26,836	-	-	-	-	-
Weighted Bills	**CWNB**	6,502,062	3,867,402	1,605,072	89,460	885,360	45,024	8,820	204	720

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	7,500,000	4,214,279	2,016,358	858,861	140,936	269,566	-	-	-
Sheet ADJ5 rows 26 - 32, column F	7,500,000	4,214,279	2,016,358	858,861	140,936	269,566	-	-	-
Sheet ADJ5 rows 26 - 32, column G	7,500,000	4,214,279	2,016,358	858,861	140,936	269,566	-	-	-
Three-year average	**7,500,000**	**4,214,279**	**2,016,358**	**858,861**	**140,936**	**269,566**	**-**	**-**	**-**

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I6 Customer Data Worksheet

Ontario

Total kWhs	25,787,863,889

Total kVAs	42,920,729

Total Approved Distribution Revenue ($)	$574,181,854

	ID	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Billing Data										
kWh from approved EDR model, Sheet 7-1, Col M	CEN	25,787,863,889	5,785,918,437	2,574,909,409	152,633,152	9,404,366,328	5,099,972,675	2,601,248,554	110,596,326	58,219,008
kW from approved EDR model, Sheet 7-1, Col S	CDEM	42,920,729			418,387	24,939,829	11,792,136	5,452,850	317,526	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		19,196,795			67,582	5,022,622	8,918,999	5,187,593		
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	25,554,349,021	5,470,966,591	2,620,609,508	6,174,749,298	3,667,466,273	5,080,177,986	2,376,988,395	108,994,196	54,396,775
Distribution Rev from EDR	CREV	574,181,854	249,235,384	76,828,016	2,666,282	149,686,141	62,746,060	25,602,538	5,373,464	2,043,969
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$7,500,000	$4,214,279	$2,016,358	$858,861	$140,936	$269,566	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$5,000,000	$2,740,702	$1,101,152	$734,944	$192,582	$197,409	$33,211	$0	$0
Weighting Factor - Services			1.0	2.0	10.0	10.0	10.0	30.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	7.0	7.0	15.0	1.0	5.0
Number of Bills	CNB	5,027,808	4,079,484	801,876	3,180	135,816	6,516	588	204	144
Number of Connections (Unmetered)	CCON	101,380							88,812	12,568
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	918,785	679,914	66,823	265	11,318	543	49	159,861	12

Bulk Customer Base	**CCB**	-	-	-	-	-	-	-	-	-
Primary Customer Base	**CCP**	918,785	679,914	66,823	265	11,318	543	49	159,861	12
Line Transformer Customer Base	**CCLT**	916,006	679,914	66,823	222	9,039	132	3	159,861	12
Secondary Customer Base	**CCS**	909,402	679,914	66,823	67	2,712	13	0	159,861	12
Weighted - Services	**CWCS**	942,864	679,914	133,646	667	27,116	132	10	88,812	12,568
Weighted Meter -Capital	**CWMC**	173,374,533	117,300,096	16,670,377	445,505	33,874,774	4,593,780	490,000	-	-
Weighted Meter Reading	**CWMR**	6,170,666	4,550,736	1,612,294	7,636	-	-	-	-	-
Weighted Bills	**CWNB**	6,711,564	4,079,484	1,603,752	22,260	950,712	45,612	8,820	204	720

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	7,500,000	4,214,279	2,016,358	858,861	140,936	269,566	-	-	-
Sheet ADJ5 rows 26 - 32, column F	7,500,000	4,214,279	2,016,358	858,861	140,936	269,566	-	-	-
Sheet ADJ5 rows 26 - 32, column G	7,500,000	4,214,279	2,016,358	858,861	140,936	269,566	-	-	-
Three-year average	**7,500,000**	**4,214,279**	**2,016,358**	**858,861**	**140,936**	**269,566**	**-**	**-**	**-**

		Residential			GS <50			GS>50 Non RIMS			GS> 50 RIMS		
		1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			68.22%			8%			2%			18%
	Cost Relative to Residential Average Cost			1.00			1.21			10.77			19.14
	Total	679914	106341947.3	156.4049973	66934	12695137.5	189.6664998	2135	3595340	1684	9451	28286843	2993
Meter Types	Cost per Meter (Installed)												
Single Phase 200 Amp - Urban	50	99,914	4995700		21,684	1084200			0			0	
Single Phase 200 Amp - Rural	150	0	0		0	0			0			0	
Central Meter	250	0	0		0	0			0			0	
Network Meter (Costs to be updated) in Existing Buildings with Ind Metering	150	85,658	12848692.11		2,000	300000			0			0	
Three-phase - No demand	210	1	210		5,000	1050000			0			0	
Smart Meters	225	7,500	1687500		0	0			0			0	
Demand without IT (usually three-phase)	500	0	0		2,000	1000000		555	277550			0	
Demand with IT	2,100		0		1,000	2,100,000		1,580	3,317,790		-	-	
Demand with IT and Interval Capability - Secondary	2,300		0			0			0		8600.41	19780943	
Demand with IT and Interval Capability - Primary	10,000		0			0			0		850.59	8505900	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0	
Smart Meters - Single Phase	158.75	462,499	73421716.25		31,250	4960937.5			0			0	
Smart Meters - Three Phase	550	24,342	13388128.95		4,000	2200000			0			0	
Single Phase - New Bulk to Individual Conversions	550		0			0			0			0	

GS >50-Intermediate			Large Use >5MW			Street Light			Unmetered Scattered Load			TOTAL		
1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
		3%			0%			0%			0%			100%
		54.09			63.94			-			-			1.31
528	4466880	8460	49	490000	10000	0	0	-	0	0	-	759011	155876147.8	205.3674424
	0			0			0			0		121,598	6079900	
	0			0			0			0		0	0	
	0			0			0			0		0	0	
	0			0			0			0		87,658	13148692.11	
	0			0			0			0		5,001	1050210	
	0			0			0			0		7,500	1687500	
	0			0			0			0		2,555	1277550	
	0			0			0			0		2,580	5417790	
106	242880			0			0			0		8,706	20023823	
422	4224000		49	490000			0			0		1,322	13219900	
	0			0			0			0		0	0	
	0			0			0			0		493,749	78382653.75	
	0			0			0			0		28,342	15588128.95	
	0			0			0			0		0	0	

		Residential			GS <50			GS>50 Non RIMS			GS> 50 RIMS		
		1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			67.37%			10%			1%			19%
	Cost Relative to Residential Average Cost			1.00			1.42			10.16			18.06
	Total	679914	112453293.8	165.3934082	68,878	16177650	234.8739801	1065	1790426.702	1681.151832	10540	31479633.77	2986.682521
Meter Types	Cost per Meter (Installed)												
Single Phase 200 Amp - Urban	50	46,914	2345700		1,878	93900			0			0	
Single Phase 200 Amp - Rural	150	0	0		-	0			0			0	
Central Meter	250	0	0		-	0			0			0	
Network Meter (Costs to be updated) in Existing Buildings with Ind Metering	150	110,000	16500000		2,000	300000			0			0	
Three-phase - No demand	210	0	0		2,000	420000			0			0	
Smart Meters	225	7,500	1687500		-	0			0			0	
Demand without IT (usually three-phase)	500	0	0		2,000	1000000		279	139397.9058			0	
Demand with IT	2,100		0		1,000	2,100,000		786	1,651,029		-	-	
Demand with IT and Interval Capability - Secondary	2,300		0			0			0		9600	22080109.39	
Demand with IT and Interval Capability - Primary	10,000		0			0			0		940	9399524.376	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0	
Smart Meters - Single Phase	158.75	489,725	77743843.75		53,000	8413750			0			0	
Smart Meters - Three Phase	550	25,775	14176250		7,000	3850000			0			0	
Single Phase - New Bulk to Individual Conversions	550		0			0			0			0	

GS >50-Intermediate			Large Use >5MW			Street Light			Unmetered Scattered Load			TOTAL		
1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
		3%			0%			0%			0%			100%
		51.15			60.46			-			-			1.33
536	4534560	8460	49	490000	10000	0	0	-	0	0	-	760982	166925564.2	219.3554699
	0			0			0			0		48,792	2439600	
	0			0			0			0		0	0	
	0			0			0			0		0	0	
	0			0			0			0		112,000	16800000	
	0			0			0			0		2,000	420000	
	0			0			0			0		7,500	1687500	
	0			0			0			0		2,279	1139397.906	
	0			0			0			0		1,786	3751028.796	
107	246560			0			0			0		9,707	22326669.39	
429	4288000		49	490000			0			0		1,418	14177524.38	
	0			0			0			0		0	0	
	0			0			0			0		542,725	86157593.75	
	0			0			0			0		32,775	18026250	
	0			0			0			0		0	0	

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I7.1 Meter Capital Worksheet - First Run

Ontario

		Residential			GS <50			GS>50 Non RIMS			GS> 50 RIMS		
		1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			67.66%			10%			0%			20%
	Cost Relative to Residential Average Cost			1.00			1.45			9.74			17.35
	Total	679914	117300096.4	172.5219607	66823	16670377	249.4706463	265	445505.2356	1681.151832	11318	33874774	2993
Meter Types	Cost per Meter (Installed)												
Single Phase 200 Amp - Urban	50	2,346	117285		668	33411.5			0			0	
Single Phase 200 Amp - Rural	150	0	0		0	0			0			0	
Central Meter	250	0	0		0	0			0			0	
Network Meter (Costs to be updated)	150	110,000	16500000		1,155	173215.5			0			0	
Three-phase - No demand	210	0	0		0	0			0			0	
Smart Meters	225	7,500	1687500		0	0			0			0	
Demand without IT (usually three-phase)	500	0	0		2,000	1000000		69	34685.86387			0	
Demand with IT	2,100		0		1,000	2,100,000		196	410,819		-	-	
Demand with IT and Interval Capability - Secondary	2,300		0			0			0		10,299	23688574	
Demand with IT and Interval Capability - Primary	10,000		0			0			0		1,019	10186200	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0	
LDC Specific 1	158.75	534,293	84819061.38		53,000	8413750			0			0	
LDC Specific 2	550	25,775	14176250		9,000	4950000			0			0	
LDC Specific 3	550		0			0			0			0	

GS >50-Intermediate			Large Use >5MW			Street Light			Unmetered Scattered Load			TOTAL		
1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
		3%			0%			0%			0%			100%
		49.04			57.96			-			-			1.32
543	4593780	8460	49	490000	10000	0	0	-	0	0	-	758912	173374532.6	228.4514313
	0			0			0			0		3,014	150696.5	
	0			0			0			0		0	0	
	0			0			0			0		0	0	
	0			0			0			0		111,155	16673215.5	
	0			0			0			0		0	0	
	0			0			0			0		7,500	1687500	
	0			0			0			0		2,069	1034685.864	
	0			0			0			0		1,196	2510819.372	
109	249780			0			0			0		10,408	23938354	
434	4344000		49	490000			0			0		1,502	15020200	
	0			0			0			0		0	0	
	0			0			0			0		587,293	93232811.38	
	0			0			0			0		34,775	19126250	
	0			0			0			0		0	0	

Weighting Factors based on Contractor Pricing

Description		1			2			3			4		
		Residential			GS <50			GS>50 Non RIMS			GS> 50 RIMS		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			71.46%			27.65%			0.90%			0.00%
	Cost Relative to Residential Average Cost			1.00			1.78			1.82			0.00
	Total	3,702,942	4,174,194	1.13	803,208	1,614,958	2.01	25,620	52,516	2.05	-	-	0
	Factor												
Residential - Urban - Outside	1.00	3,236,604	3,236,604			0			0			0	
Residential - Urban - Outside with other services	1.00		0			0			0			0	
Residential - Urban - Inside	2.00	461,424	922,848			0			0			0	
Residential - Urban - Inside - with other services	1.00		0			0			0			0	
Residential - Rural - Outside	3.00	4,914	14,742			0			0			0	
Residential - Rural - Outside with other services	2.00		0			0			0			0	
LDC Specific 1			0			0			0			0	
LDC Specific 2			0			0			0			0	
GS - Walking	2.00		0		794,666	1,589,333		24,344	48,687			0	
GS - Walking - with other services	3.00		0		8,542	25,625		1,276	3,829			0	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0			0	
GS - Vehicle with other services	3.00		0			0			0			0	
LDC Specific 3			0			0			0			0	
LDC Specific 4	0.00		0			0			0			0	
Interval	49.00		0			0			0		0	0	
LDC Specific 5			0			0			0			0	
LDC Specific 6			0			0			0			0	

5			6			7			9					
GS >50-Intermediate			Large Use >5MW			Street Light			Unmetered Scattered Load			TOTAL		
Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
		0.00%			0.00%			0.00%			0.00%			100.00%
		0.00			0.00			0.00			0.00			4.60
-	-	**0**	-	-	**0**	-	-	**0**	-	-	**0**	**4,531,770**	**5,841,668**	**5**
	0			0			0			0		3,236,604	3,236,604	
	0			0			0			0		-	-	
	0			0			0			0		461,424	922,848	
	0			0			0			0		-	-	
	0			0			0			0		4,914	14,742	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		819,010	1,638,020	
	0			0			0			0		9,818	29,454	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
0	0		0	0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I7.2 Meter Reading Worksheet

Ontario

Weighting Factors based on Contractor Pricing

Description		1			2			3			4		
		Residential			GS <50			GS>50 Non RIMS			GS> 50 RIMS		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			72.56%			26.99%			0.45%			0.00%
	Cost Relative to Residential Average Cost			1.00			1.79			1.87			0.00
	Total	3,867,402	4,338,654	1.12	802,536	1,613,614	2.01	12,780	26,836	2.10	-	-	0
	Factor												
Residential - Urban - Outside	1.00	3,401,064	3,401,064			0			0			0	
Residential - Urban - Outside with other services	1.00		0			0			0			0	
Residential - Urban - Inside	2.00	461,424	922,848			0			0			0	
Residential - Urban - Inside - with other services	1.00		0			0			0			0	
Residential - Rural - Outside	3.00	4,914	14,742			0			0			0	
Residential - Rural - Outside with other services	2.00		0			0			0			0	
LDC Specific 1			0			0			0			0	
LDC Specific 2			0			0			0			0	
GS - Walking	2.00		0		793,994	1,587,989		11,504	23,007			0	
GS - Walking - with other services	3.00		0		8,542	25,625		1,276	3,829			0	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0			0	
GS - Vehicle with other services	3.00		0			0			0			0	
LDC Specific 3			0			0			0			0	
LDC Specific 4	0.00		0			0			0			0	
Interval	49.00		0			0			0		0	0	
LDC Specific 5			0			0			0			0	
LDC Specific 6			0			0			0			0	

5			6			7			9					
GS >50-Intermediate			Large Use >5MW			Street Light			Unmetered Scattered Load			TOTAL		
Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
		0.00%			0.00%			0.00%			0.00%			100.00%
		0.00			0.00			0.00			0.00			4.66
-	-	**0**	-	-	**0**	-	-	**0**	-	-	**0**	**4,682,718**	**5,979,104**	**5**
	0			0			0			0		3,401,064	3,401,064	
	0			0			0			0		-	-	
	0			0			0			0		461,424	922,848	
	0			0			0			0		-	-	
	0			0			0			0		4,914	14,742	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		805,498	1,610,996	
	0			0			0			0		9,818	29,454	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
0	0		0	0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I7.2 Meter Reading Worksheet

Ontario

Weighting Factors based on Contractor Pricing

Description		1			2			3			4		
		Residential			GS <50			GS>50 Non RIMS			GS> 50 RIMS		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			73.75%			26.13%			0.12%			0.00%
	Cost Relative to Residential Average Cost			1.00			1.80			2.15			0.00
	Total	4,079,484	4,550,736	1.12	801,876	1,612,294	2.01	3,180	7,636	2.40	-	-	0
	Factor												
Residential - Urban - Outside	1.00	3,613,146	3,613,146			0			0			0	
Residential - Urban - Outside with other services	1.00		0			0			0			0	
Residential - Urban - Inside	2.00	461,424	922,848			0			0			0	
Residential - Urban - Inside - with other services	1.00		0			0			0			0	
Residential - Rural - Outside	3.00	4,914	14,742			0			0			0	
Residential - Rural - Outside with other services	2.00		0			0			0			0	
LDC Specific 1			0			0			0			0	
LDC Specific 2			0			0			0			0	
GS - Walking	2.00		0		793,334	1,586,669		1,904	3,807			0	
GS - Walking - with other services	3.00		0		8,542	25,625		1,276	3,829			0	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0			0	
GS - Vehicle with other services	3.00		0			0			0			0	
LDC Specific 3			0			0			0			0	
LDC Specific 4	0.00		0			0			0			0	
Interval	49.00		0			0			0		0	0	
LDC Specific 5			0			0			0			0	
LDC Specific 6			0			0			0			0	

5			6			7			9					
GS >50-Intermediate			Large Use >5MW			Street Light			Unmetered Scattered Load			TOTAL		
Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
		0.00%			0.00%			0.00%			0.00%			100.00%
		0.00			0.00			0.00			0.00			4.96
-	-	**0**	-	-	**0**	-	-	**0**	-	-	**0**	**4,884,540**	**6,170,666**	**6**
	0			0			0			0		3,613,146	3,613,146	
	0			0			0			0		-	-	
	0			0			0			0		461,424	922,848	
	0			0			0			0		-	-	
	0			0			0			0		4,914	14,742	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		795,238	1,590,476	
	0			0			0			0		9,818	29,454	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	
0	0		0	0			0			0		-	-	
	0			0			0			0		-	-	
	0			0			0			0		-	-	

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I8 Demand Data Worksheet

Ontario

This is an input sheet for demand allocators.

Primary	3.30%	3.30%	3.30%	3.30%	3.30%	1.41%		3.30%	3.30%
Secondary	2.27%	2.27%	2.27%	2.27%	2.27%		-	2.27%	2.27%

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	4,419,219	1,122,377	566,568	248,700	1,304,643	796,678	373,652	-	6,602
Bulk Delivery CP	BCP1	4,419,219	1,122,377	566,568	248,700	1,304,643	796,678	373,652	-	6,602
Total Sytem CP	DCP1	4,419,219	1,122,377	566,568	248,700	1,304,643	796,678	373,652	-	6,602
4 CP										
Transformation CP	TCP4	16,592,239	4,333,248	1,984,907	985,416	4,925,186	2,937,032	1,376,644	23,733	26,073
Bulk Delivery CP	BCP4	16,592,239	4,333,248	1,984,907	985,416	4,925,186	2,937,032	1,376,644	23,733	26,073
Total Sytem CP	DCP4	16,592,239	4,333,248	1,984,907	985,416	4,925,186	2,937,032	1,376,644	23,733	26,073
12 CP										
Transformation CP	TCP12	46,279,562	11,573,094	5,086,473	2,620,099	14,380,479	8,401,588	3,955,999	178,770	83,059
Bulk Delivery CP	BCP12	46,279,562	11,573,094	5,086,473	2,620,099	14,380,479	8,401,588	3,955,999	178,770	83,059
Total Sytem CP	DCP12	46,279,562	11,573,094	5,086,473	2,620,099	14,380,479	8,401,588	3,955,999	178,770	83,059
NON CO_INCIDENT PEAK										
1 NCP										
Classification NCP from Load Data Provider	DNCP1	4,745,625	1,299,109	598,172	288,919	1,332,383	804,294	386,774	27,553	8,421
Primary NCP	PNCP1	4,745,188	1,299,109	598,172	288,919	1,332,383	804,294	386,774	27,553	7,984
Line Transformer NCP	LTNCP1	3,442,125	1,299,109	598,172	241,247	1,053,274	195,973	18,813	27,553	7,984
Secondary NCP	SNCP1	2,340,772	1,299,109	598,172	72,374	315,982	19,597	-	27,553	7,984
4 NCP										
Classification NCP from Load Data Provider	DNCP4	18,219,018	4,941,942	2,231,319	1,140,368	5,155,375	3,112,728	1,496,059	108,701	32,526
Primary NCP	PNCP4	18,219,018	4,941,942	2,231,319	1,140,368	5,155,375	3,112,728	1,496,059	108,701	32,526
Line Transformer NCP	LTNCP4	13,173,330	4,941,942	2,231,319	952,206	4,075,422	758,444	72,770	108,701	32,526
Secondary NCP	SNCP4	8,898,621	4,941,942	2,231,319	285,662	1,222,627	75,844	-	108,701	32,526
12 NCP										
Classification NCP from Load Data Provider	DNCP12	50,393,418	13,291,231	5,939,051	2,956,589	14,654,812	8,893,989	4,254,770	312,571	90,404
Primary NCP	PNCP12	50,393,418	13,291,231	5,939,051	2,956,589	14,654,812	8,893,989	4,254,770	312,571	90,404
Line Transformer NCP	LTNCP12	36,060,969	13,291,231	5,939,051	2,468,748	11,584,908	2,167,099	206,957	312,571	90,404
Secondary NCP	SNCP12	24,066,063	13,291,231	5,939,051	740,624	3,475,472	216,710	-	312,571	90,404

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I8 Demand Data Worksheet

Ontario

This is an input sheet for demand allocators.

Primary	3.30%	3.30%	3.30%	3.30%	3.30%	1.41%		3.30%	3.30%
Secondary	2.27%	2.27%	2.27%	2.27%	2.27%		-	2.27%	2.27%

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	4,448,159	1,216,663	533,959	124,648	1,390,311	800,780	375,171	-	6,627
Bulk Delivery CP	BCP1	4,448,159	1,216,663	533,959	124,648	1,390,311	800,780	375,171	-	6,627
Total Sytem CP	DCP1	4,448,159	1,216,663	533,959	124,648	1,390,311	800,780	375,171	-	6,627
4 CP										
Transformation CP	TCP4	16,756,082	4,670,403	1,888,492	513,395	5,289,353	2,956,534	1,387,250	24,318	26,335
Bulk Delivery CP	BCP4	16,756,082	4,670,403	1,888,492	513,395	5,289,353	2,956,534	1,387,250	24,318	26,335
Total Sytem CP	DCP4	16,756,082	4,670,403	1,888,492	513,395	5,289,353	2,956,534	1,387,250	24,318	26,335
12 CP										
Transformation CP	TCP12	46,744,948	12,470,655	4,904,394	1,320,896	15,388,298	8,394,332	4,003,038	179,850	83,486
Bulk Delivery CP	BCP12	46,744,948	12,470,655	4,904,394	1,320,896	15,388,298	8,394,332	4,003,038	179,850	83,486
Total Sytem CP	DCP12	46,744,948	12,470,655	4,904,394	1,320,896	15,388,298	8,394,332	4,003,038	179,850	83,486
NON CO_INCIDENT PEAK										
1 NCP										
Classification NCP from Load Data Provider	DNCP1	4,755,338	1,368,225	562,196	173,463	1,419,215	808,429	387,593	27,716	8,502
Primary NCP	PNCP1	4,754,898	1,368,225	562,196	173,463	1,419,215	808,429	387,593	27,716	8,061
Line Transformer NCP	LTNCP1	3,455,415	1,368,225	562,196	145,033	1,128,352	196,977	18,855	27,716	8,061
Secondary NCP	SNCP1	2,367,911	1,368,225	562,196	43,510	338,506	19,698	-	27,716	8,061
4 NCP										
Classification NCP from Load Data Provider	DNCP4	18,213,615	5,163,024	2,107,149	663,704	5,513,664	3,124,834	1,499,278	109,294	32,668
Primary NCP	PNCP4	18,213,615	5,163,024	2,107,149	663,704	5,513,664	3,124,834	1,499,278	109,294	32,668
Line Transformer NCP	LTNCP4	13,185,033	5,163,024	2,107,149	554,925	4,383,660	761,379	72,935	109,294	32,668
Secondary NCP	SNCP4	8,969,848	5,163,024	2,107,149	166,478	1,315,098	76,138	-	109,294	32,668
12 NCP										
Classification NCP from Load Data Provider	DNCP12	50,402,015	13,822,064	5,715,942	1,519,141	15,724,136	8,942,626	4,272,439	314,779	90,888
Primary NCP	PNCP12	50,402,015	13,822,064	5,715,942	1,519,141	15,724,136	8,942,626	4,272,439	314,779	90,888
Line Transformer NCP	LTNCP12	36,102,114	13,822,064	5,715,942	1,270,159	12,501,536	2,178,907	207,840	314,779	90,888
Secondary NCP	SNCP12	24,293,072	13,822,064	5,715,942	381,048	3,750,461	217,891	-	314,779	90,888

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I8 Demand Data Worksheet

Ontario

This is an input sheet for demand allocators.

Primary	3.30%	3.30%	3.30%	3.30%	3.30%	1.41%		3.30%	3.30%
Secondary	2.27%	2.27%	2.27%	2.27%	2.27%		-	2.27%	2.27%

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	4,506,473	1,258,742	586,867	27,290	1,443,422	806,105	377,422	-	6,624
Bulk Delivery CP	BCP1	4,506,473	1,258,742	586,867	27,290	1,443,422	806,105	377,422	-	6,624
Total Sytem CP	DCP1	4,506,473	1,258,742	586,867	27,290	1,443,422	806,105	377,422	-	6,624
4 CP										
Transformation CP	TCP4	17,009,313	4,850,123	2,059,029	125,263	5,544,814	2,979,338	1,399,989	24,319	26,437
Bulk Delivery CP	BCP4	17,009,313	4,850,123	2,059,029	125,263	5,544,814	2,979,338	1,399,989	24,319	26,437
Total Sytem CP	DCP4	17,009,313	4,850,123	2,059,029	125,263	5,544,814	2,979,338	1,399,989	24,319	26,437
12 CP										
Transformation CP	TCP12	46,789,781	12,822,439	5,112,399	303,142	15,960,251	8,388,312	3,938,802	180,781	83,656
Bulk Delivery CP	BCP12	46,789,781	12,822,439	5,112,399	303,142	15,960,251	8,388,312	3,938,802	180,781	83,656
Total Sytem CP	DCP12	46,789,781	12,822,439	5,112,399	303,142	15,960,251	8,388,312	3,938,802	180,781	83,656
NON CO_INCIDENT PEAK										
1 NCP										
Classification NCP from Load Data Provider	DNCP1	4,788,341	1,413,300	625,514	53,541	1,457,332	813,818	389,027	27,468	8,340
Primary NCP	PNCP1	4,787,908	1,413,300	625,514	53,541	1,457,332	813,818	389,027	27,468	7,908
Line Transformer NCP	LTNCP1	3,500,133	1,413,300	625,514	44,892	1,163,841	198,286	18,924	27,468	7,908
Secondary NCP	SNCP1	2,456,639	1,413,300	625,514	13,468	349,152	19,829	-	27,468	7,908
4 NCP										
Classification NCP from Load Data Provider	DNCP4	18,300,148	5,289,805	2,268,872	193,029	5,757,221	3,141,494	1,508,886	108,313	32,529
Primary NCP	PNCP4	18,300,148	5,289,805	2,268,872	193,029	5,757,221	3,141,494	1,508,886	108,313	32,529
Line Transformer NCP	LTNCP4	13,297,966	5,289,805	2,268,872	161,849	4,597,777	765,420	73,401	108,313	32,529
Secondary NCP	SNCP4	9,203,948	5,289,805	2,268,872	48,555	1,379,333	76,542	-	108,313	32,529
12 NCP										
Classification NCP from Load Data Provider	DNCP12	50,438,590	14,258,321	6,094,628	345,056	16,187,270	8,894,032	4,262,119	306,547	90,616
Primary NCP	PNCP12	50,438,590	14,258,321	6,094,628	345,056	16,187,270	8,894,032	4,262,119	306,547	90,616
Line Transformer NCP	LTNCP12	36,341,106	14,258,321	6,094,628	289,319	12,927,323	2,167,018	207,334	306,547	90,616
Secondary NCP	SNCP12	24,931,806	14,258,321	6,094,628	86,796	3,878,197	216,702	-	306,547	90,616

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I9 Direct Allocation Worksheet

Ontario

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediat	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load

Instructions:
To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

1995	Contributions and Grants - Credit	$0	Yes								

Instructions:
The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

1805	Land	$0	Yes								
1806	Land Rights	$0	Yes								
1808	Buildings and Fixtures	$0	Yes								
1810	Leasehold Improvements	$0	Yes								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes								
1825	Storage Battery Equipment	$0	Yes								
1830	Poles, Towers and Fixtures	$0	Yes								
1835	Overhead Conductors and Devices	$0	Yes								
1840	Underground Conduit	$29,713,837	Yes				$1,069,698	$3,862,799	$24,781,340		
1845	Underground Conductors and Devices	$12,662,351	Yes				$455,845	$1,646,106	$10,560,400		
1850	Line Transformers	$0	Yes								
1855	Services	$0	Yes								
1860	Meters	$0	Yes								
1905	Land	$0	Yes								
1906	Land Rights	$0	Yes								
1908	Buildings and Fixtures	$0	Yes								
1910	Leasehold Improvements	$0	Yes								
1915	Office Furniture and Equipment	$0	Yes								
1920	Computer Equipment - Hardware	$0	Yes								
1925	Computer Software	$0	Yes								
1930	Transportation Equipment	$0	Yes								
1935	Stores Equipment	$0	Yes								
1940	Tools, Shop and Garage Equipment	$0	Yes								
1945	Measurement and Testing Equipment	$0	Yes								
1950	Power Operated Equipment	$0	Yes								
1955	Communication Equipment	$0	Yes								
1960	Miscellaneous Equipment	$0	Yes								

1970	Load Management Controls - Customer Premises	$0	Yes								
1975	Load Management Controls - Utility Premises	$0	Yes								
1980	System Supervisory Equipment	$0	Yes								
1990	Other Tangible Property	$0	Yes								
2005	Property Under Capital Leases	$0	Yes								
2010	Electric Plant Purchased or Sold	$0	Yes								
2050	Completed Construction Not Classified--Electric	$0	Yes								
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($21,985,215)	Yes				($791,468)	($2,858,078)	($18,335,669)		
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes								
	Directly Allocated Net Fixed Assets			**$0**	**$0**	**$0**	**$734,075**	**$2,650,827**	**$17,006,071**	**$0**	**$0**
5005	Operation Supervision and Engineering	$0	Yes								
5010	Load Dispatching	$0	Yes								
5012	Station Buildings and Fixtures Expense	$0	Yes								
5014	Transformer Station Equipment - Operation Labour	$0	Yes								
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes								
5016	Distribution Station Equipment - Operation Labour	$0	Yes								
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes								
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes								
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes								
5030	Overhead Subtransmission Feeders - Operation	$0	Yes								
5035	Overhead Distribution Transformers-Operation	$0	Yes								
5040	Underground Distribution Lines and Feeders - Operation Labour	$42,517	Yes				$1,531	$5,527	$35,459		
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$47,577	Yes				$1,713	$6,185	$39,679		
5050	Underground Subtransmission Feeders Operation	$0	Yes								
5055	Underground Distribution Transformers Operation	$12,008,406	Yes			$393,936	$2,884,519	$5,520,433	$3,209,518		
5065	Meter Expense	$0	Yes								
5070	Customer Premises - Operation Labour	$0	Yes								
5075	Customer Premises - Materials and Expenses	$0	Yes								
5085	Miscellaneous Distribution Expense	$0	Yes								
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes								
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes								

5096	Other Rent	$0	Yes								
5105	Maintenance Supervision and Engineering	$0	Yes								
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes								
5112	Maintenance of Transformer Station Equipment	$0	Yes								
5114	Maintenance of Distribution Station Equipment	$0	Yes								
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes								
5125	Maintenance of Overhead Conductors and Devices	$0	Yes								
5130	Maintenance of Overhead Services	$0	Yes								
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes								
5145	Maintenance of Underground Conduit	$0	Yes								
5150	Maintenance of Underground Conductors and Devices	$218,770	Yes				$7,876	$28,440	$182,454		
5155	Maintenance of Underground Services	$0	Yes								
5160	Maintenance of Line Transformers	$129,805	Yes			$4,258	$31,180	$59,673	$34,693		
5175	Maintenance of Meters	$0	Yes								
5305	Supervision	$0	Yes								
5310	Meter Reading Expense	$0	Yes								
5315	Customer Billing	$0	Yes								
5320	Collecting	$0	Yes								
5325	Collecting- Cash Over and Short	$0	Yes								
5330	Collection Charges	$0	Yes								
5335	Bad Debt Expense	$0	Yes								
5340	Miscellaneous Customer Accounts Expenses	$0	Yes								
5405	Supervision	$0	Yes								
5410	Community Relations - Sundry	$0	Yes								
5415	Energy Conservation	$1,539,975.00	Yes	$1,134,282	$275,428		$32,571	$65,142	$32,552		
5420	Community Safety Program	$0	Yes								
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes								
5505	Supervision	$0	Yes								
5510	Demonstrating and Selling Expense	$0	Yes								
5515	Advertising Expense	$0	Yes								
5520	Miscellaneous Sales Expense	$0	Yes								
5605	Executive Salaries and Expenses	$0	Yes								
5610	Management Salaries and Expenses	$0	Yes								
5615	General Administrative Salaries and Expenses	$0	Yes								
5620	Office Supplies and Expenses	$0	Yes								
5625	Administrative Expense Transferred Credit	$0	Yes								
5630	Outside Services Employed	$0	Yes								
5635	Property Insurance	$0	Yes								
5640	Injuries and Damages	$0	Yes								
5645	Employee Pensions and Benefits	$0	Yes								
5650	Franchise Requirements	$0	Yes								
5655	Regulatory Expenses	$0	Yes								
5660	General Advertising Expenses	$0	Yes								
5665	Miscellaneous General Expenses	$0	Yes								
5670	Rent	$0	Yes								

5675	Maintenance of General Plant	$0	Yes								
5680	Electrical Safety Authority Fees	$0	Yes								
5705	Amortization Expense - Property, Plant, and Equipment	$1,595,413	Yes				$57,435	$207,404	$1,330,574		
5710	Amortization of Limited Term Electric Plant	$0	Yes								
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes								
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes								
6105	Taxes Other Than Income Taxes	$0	Yes								
6205	Donations	$0	Yes								
6210	Life Insurance	$0	Yes								
6215	Penalties	$0	Yes								
6225	Other Deductions	$0	Yes								
	Total Expenses			$1,134,282	$275,428	$398,194	$3,016,825	$5,892,804	$4,864,929	$0	$0
	Depreciation Expense			$0	$0	$0	$57,435	$207,404	$1,330,574	$0	$0

Total Net Fixed Assets Excluding Gen Plant	**$3,303,940,573**	**Allocated**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediat**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Approved Total PILs	**$40,850,253**	**$252,116**	$0	$0	$0	$9,076	$32,775	$210,265	$0	$0
Approved Total Return on Debt	**$68,606,142**	**$423,417**	$0	$0	$0	$15,243	$55,044	$353,130	$0	$0
Approved Total Return on Equity	**$65,524,896**	**$404,401**	$0	$0	$0	$14,558	$52,572	$337,270	$0	$0
		Total	**$1,134,282**	**$275,428**	**$398,194**	**$3,055,703**	**$6,033,195**	**$5,765,595**	**$0**	**$0**

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I9 Direct Allocation Worksheet

Ontario

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediat	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load

Instructions:
To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

1995	Contributions and Grants - Credit	$0	Yes								

Instructions:
The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

1805	Land	$0	Yes								
1806	Land Rights	$0	Yes								
1808	Buildings and Fixtures	$0	Yes								
1810	Leasehold Improvements	$0	Yes								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes								
1825	Storage Battery Equipment	$0	Yes								
1830	Poles, Towers and Fixtures	$0	Yes								
1835	Overhead Conductors and Devices	$0	Yes								
1840	Underground Conduit	$31,362,972	Yes				$1,129,067	$4,077,186	$26,156,719		
1845	Underground Conductors and Devices	$14,158,363	Yes				$509,701	$1,840,587	$11,808,075		
1850	Line Transformers	$0	Yes								
1855	Services	$0	Yes								
1860	Meters	$0	Yes								
1905	Land	$0	Yes								
1906	Land Rights	$0	Yes								
1908	Buildings and Fixtures	$0	Yes								
1910	Leasehold Improvements	$0	Yes								
1915	Office Furniture and Equipment	$0	Yes								
1920	Computer Equipment - Hardware	$0	Yes								
1925	Computer Software	$0	Yes								
1930	Transportation Equipment	$0	Yes								
1935	Stores Equipment	$0	Yes								
1940	Tools, Shop and Garage Equipment	$0	Yes								
1945	Measurement and Testing Equipment	$0	Yes								
1950	Power Operated Equipment	$0	Yes								
1955	Communication Equipment	$0	Yes								
1960	Miscellaneous Equipment	$0	Yes								

1970	Load Management Controls - Customer Premises	$0	Yes								
1975	Load Management Controls - Utility Premises	$0	Yes								
1980	System Supervisory Equipment	$0	Yes								
1990	Other Tangible Property	$0	Yes								
2005	Property Under Capital Leases	$0	Yes								
2010	Electric Plant Purchased or Sold	$0	Yes								
2050	Completed Construction Not Classified--Electric	$0	Yes								
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($23,631,197)	Yes				($850,723)	($3,072,056)	($19,708,418)		
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes								
	Directly Allocated Net Fixed Assets			**$0**	**$0**	**$0**	**$788,045**	**$2,845,717**	**$18,256,376**	**$0**	**$0**
5005	Operation Supervision and Engineering	$0	Yes								
5010	Load Dispatching	$0	Yes								
5012	Station Buildings and Fixtures Expense	$0	Yes								
5014	Transformer Station Equipment - Operation Labour	$0	Yes								
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes								
5016	Distribution Station Equipment - Operation Labour	$0	Yes								
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes								
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes								
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes								
5030	Overhead Subtransmission Feeders - Operation	$0	Yes								
5035	Overhead Distribution Transformers-Operation	$0	Yes								
5040	Underground Distribution Lines and Feeders - Operation Labour	$44,819	Yes				$1,613	$5,826	$37,380		
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$70,600	Yes				$2,542	$9,178	$58,880		
5050	Underground Subtransmission Feeders Operation	$0	Yes								
5055	Underground Distribution Transformers Operation	$11,984,664	Yes			$195,656	$3,042,002	$5,532,062	$3,214,944		
5065	Meter Expense	$0	Yes								
5070	Customer Premises - Operation Labour	$0	Yes								
5075	Customer Premises - Materials and Expenses	$0	Yes								
5085	Miscellaneous Distribution Expense	$0	Yes								
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes								
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes								
5096	Other Rent	$0	Yes								

5105	Maintenance Supervision and Engineering	$0	Yes								
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes								
5112	Maintenance of Transformer Station Equipment	$0	Yes								
5114	Maintenance of Distribution Station Equipment	$0	Yes								
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes								
5125	Maintenance of Overhead Conductors and Devices	$0	Yes								
5130	Maintenance of Overhead Services	$0	Yes								
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes								
5145	Maintenance of Underground Conduit	$0	Yes								
5150	Maintenance of Underground Conductors and Devices	$237,494	Yes				$8,550	$30,874	$198,070		
5155	Maintenance of Underground Services	$0	Yes								
5160	Maintenance of Line Transformers	$129,044	Yes			($6,700)	$32,753	$68,376	$34,615		
5175	Maintenance of Meters	$0	Yes								
5305	Supervision	$0	Yes								
5310	Meter Reading Expense	$0	Yes								
5315	Customer Billing	$0	Yes								
5320	Collecting	$0	Yes								
5325	Collecting- Cash Over and Short	$0	Yes								
5330	Collection Charges	$0	Yes								
5335	Bad Debt Expense	$0	Yes								
5340	Miscellaneous Customer Accounts Expenses	$0	Yes								
5405	Supervision	$0	Yes								
5410	Community Relations - Sundry	$0	Yes								
5415	Energy Conservation	$1,618,945.00	Yes	$1,193,642	$289,951		$33,838	$67,677	$33,837		
5420	Community Safety Program	$0	Yes								
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes								
5505	Supervision	$0	Yes								
5510	Demonstrating and Selling Expense	$0	Yes								
5515	Advertising Expense	$0	Yes								
5520	Miscellaneous Sales Expense	$0	Yes								
5605	Executive Salaries and Expenses	$0	Yes								
5610	Management Salaries and Expenses	$0	Yes								
5615	General Administrative Salaries and Expenses	$0	Yes								
5620	Office Supplies and Expenses	$0	Yes								
5625	Administrative Expense Transferred Credit	$0	Yes								
5630	Outside Services Employed	$0	Yes								
5635	Property Insurance	$0	Yes								
5640	Injuries and Damages	$0	Yes								
5645	Employee Pensions and Benefits	$0	Yes								
5650	Franchise Requirements	$0	Yes								
5655	Regulatory Expenses	$0	Yes								
5660	General Advertising Expenses	$0	Yes								
5665	Miscellaneous General Expenses	$0	Yes								
5670	Rent	$0	Yes								
5675	Maintenance of General Plant	$0	Yes								
5680	Electrical Safety Authority Fees	$0	Yes								

5705	Amortization Expense - Property, Plant, and Equipment	$1,696,551	Yes				$61,076	$220,552	$1,414,923		
5710	Amortization of Limited Term Electric Plant	$0	Yes								
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes								
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes								
6105	Taxes Other Than Income Taxes	$0	Yes								
6205	Donations	$0	Yes								
6210	Life Insurance	$0	Yes								
6215	Penalties	$0	Yes								
6225	Other Deductions	$0	Yes								
	Total Expenses			$1,193,642	$289,951	$188,956	$3,182,374	$5,934,546	$4,992,649	$0	$0
	Depreciation Expense			$0	$0	$0	$61,076	$220,552	$1,414,923	$0	$0

Total Net Fixed Assets Excluding Gen Plant	**$3,611,105,939**	**Allocated**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediat**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Approved Total PILs	**$39,469,707**	**$239,261**	$0	$0	$0	$8,613	$31,104	$199,544	$0	$0
Approved Total Return on Debt	**$71,473,599**	**$433,265**	$0	$0	$0	$15,598	$56,324	$361,343	$0	$0
Approved Total Return on Equity	**$77,458,394**	**$469,545**	$0	$0	$0	$16,904	$61,041	$391,600	$0	$0
		Total	**$1,193,642**	**$289,951**	**$188,956**	**$3,223,488**	**$6,083,015**	**$5,945,137**	**$0**	**$0**

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet I9 Direct Allocation Worksheet - First Run

Ontario

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediat	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
						($0.0000000015716)					
						$128,016					
1995	Contributions and Grants - Credit	$0	Yes								
1805	Land	$0	Yes								
1806	Land Rights	$0	Yes								
1808	Buildings and Fixtures	$0	Yes								
1810	Leasehold Improvements	$0	Yes								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes								
1825	Storage Battery Equipment	$0	Yes								
1830	Poles, Towers and Fixtures	$0	Yes								
1835	Overhead Conductors and Devices	$0	Yes								
1840	Underground Conduit	$33,205,282	Yes				$1,195,390	$4,316,687	$27,693,205		
1845	Underground Conductors and Devices	$15,771,076	Yes				$567,759	$2,050,240	$13,153,077		
1850	Line Transformers	$0	Yes								
1855	Services	$0	Yes								
1860	Meters	$0	Yes								
1905	Land	$0	Yes								
1906	Land Rights	$0	Yes								
1908	Buildings and Fixtures	$0	Yes								
1910	Leasehold Improvements	$0	Yes								
1915	Office Furniture and Equipment	$0	Yes								
1920	Computer Equipment - Hardware	$0	Yes								
1925	Computer Software	$0	Yes								
1930	Transportation Equipment	$0	Yes								
1935	Stores Equipment	$0	Yes								
1940	Tools, Shop and Garage Equipment	$0	Yes								
1945	Measurement and Testing Equipment	$0	Yes								
1950	Power Operated Equipment	$0	Yes								
1955	Communication Equipment	$0	Yes								
1960	Miscellaneous Equipment	$0	Yes								
1970	Load Management Controls - Customer Premises	$0	Yes								

Instructions:
To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line

Instructions:
The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications

1975	Load Management Controls - Utility Premises	$0	Yes								
1980	System Supervisory Equipment	$0	Yes								
1990	Other Tangible Property	$0	Yes								
2005	Property Under Capital Leases	$0	Yes								
2010	Electric Plant Purchased or Sold	$0	Yes								
2050	Completed Construction Not Classified--Electric	$0	Yes								
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	($25,395,836)	Yes				($914,250)	($3,301,459)	($21,180,127)		
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes								
	Directly Allocated Net Fixed Assets			**$0**	**$0**	**$0**	**$848,899**	**$3,065,468**	**$19,666,155**	**$0**	**$0**
5005	Operation Supervision and Engineering	$0	Yes								
5010	Load Dispatching	$0	Yes								
5012	Station Buildings and Fixtures Expense	$0	Yes								
5014	Transformer Station Equipment - Operation Labour	$0	Yes								
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes								
5016	Distribution Station Equipment - Operation Labour	$0	Yes								
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes								
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes								
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes								
5030	Overhead Subtransmission Feeders - Operation	$0	Yes								
5035	Overhead Distribution Transformers-Operation	$0	Yes								
5040	Underground Distribution Lines and Feeders - Operation Labour	$48,396	Yes				$1,742	$6,291	$40,363		
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$76,007	Yes				$2,736	$9,881	$63,390		
5050	Underground Subtransmission Feeders Operation	$0	Yes								
5055	Underground Distribution Transformers Operation	$11,939,303	Yes			$42,032	$3,123,786	$5,554,356	$3,219,128		
5065	Meter Expense	$0	Yes								
5070	Customer Premises - Operation Labour	$0	Yes								
5075	Customer Premises - Materials and Expenses	$0	Yes								
5085	Miscellaneous Distribution Expense	$0	Yes								
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes								
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes								
5096	Other Rent	$0	Yes								
5105	Maintenance Supervision and Engineering	$0	Yes								
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes								

5112	Maintenance of Transformer Station Equipment	$0	Yes								
5114	Maintenance of Distribution Station Equipment	$0	Yes								
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes								
5125	Maintenance of Overhead Conductors and Devices	$0	Yes								
5130	Maintenance of Overhead Services	$0	Yes								
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes								
5145	Maintenance of Underground Conduit	$0	Yes								
5150	Maintenance of Underground Conductors and Devices	$257,950	Yes				$9,286	$33,534	$215,130		
5155	Maintenance of Underground Services	$0	Yes								
5160	Maintenance of Line Transformers	$128,016	Yes			$451	$33,490	$59,563	$34,512		
5175	Maintenance of Meters	$0	Yes								
5305	Supervision	$0	Yes								
5310	Meter Reading Expense	$0	Yes								
5315	Customer Billing	$0	Yes								
5320	Collecting	$0	Yes								
5325	Collecting- Cash Over and Short	$0	Yes								
5330	Collection Charges	$0	Yes								
5335	Bad Debt Expense	$0	Yes								
5340	Miscellaneous Customer Accounts Expenses	$0	Yes								
5405	Supervision	$0	Yes								
5410	Community Relations - Sundry	$0	Yes								
5415	Energy Conservation	$1,736,566	Yes	$1,283,551	$312,079		$35,234	$70,468	$35,234		
5420	Community Safety Program	$0	Yes								
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes								
5505	Supervision	$0	Yes								
5510	Demonstrating and Selling Expense	$0	Yes								
5515	Advertising Expense	$0	Yes								
5520	Miscellaneous Sales Expense	$0	Yes								
5605	Executive Salaries and Expenses	$0	Yes								
5610	Management Salaries and Expenses	$0	Yes								
5615	General Administrative Salaries and Expenses	$0	Yes								
5620	Office Supplies and Expenses	$0	Yes								
5625	Administrative Expense Transferred Credit	$0	Yes								
5630	Outside Services Employed	$0	Yes								
5635	Property Insurance	$0	Yes								
5640	Injuries and Damages	$0	Yes								
5645	Employee Pensions and Benefits	$0	Yes								
5650	Franchise Requirements	$0	Yes								
5655	Regulatory Expenses	$0	Yes								
5660	General Advertising Expenses	$0	Yes								
5665	Miscellaneous General Expenses	$0	Yes								
5670	Rent	$0	Yes								
5675	Maintenance of General Plant	$0	Yes								
5680	Electrical Safety Authority Fees	$0	Yes								
5705	Amortization Expense - Property, Plant, and Equipment	$1,832,728	Yes				$65,978	$238,255	$1,528,495		
5710	Amortization of Limited Term Electric Plant	$0	Yes								
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes								

5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes								
6105	Taxes Other Than Income Taxes	$0	Yes								
6205	Donations	$0	Yes								
6210	Life Insurance	$0	Yes								
6215	Penalties	$0	Yes								
6225	Other Deductions	$0	Yes								
	Total Expenses			$1,283,551	$312,079	$42,483	$3,272,252	$5,972,349	$5,136,252	$0	$0
	Depreciation Expense			$0	$0	$0	$65,978	$238,255	$1,528,495	$0	$0

Total Net Fixed Assets Excluding Gen Plant	**$3,874,149,534**	**Allocated**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediat**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Approved Total PILs	**$38,100,719**	**$231,905**	$0	$0	$0	$8,349	$30,148	$193,409	$0	$0
Approved Total Return on Debt	**$76,864,002**	**$467,843**	$0	$0	$0	$16,842	$60,820	$390,181	$0	$0
Approved Total Return on Equity	**$83,475,416**	**$508,084**	$0	$0	$0	$18,291	$66,051	$423,742	$0	$0
		Total	**$1,283,551**	**$312,079**	**$42,483**	**$3,315,734**	**$6,129,367**	**$6,143,584**	**$0**	**$0**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O1 Revenue to Cost Summary Worksheet

Ontario

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	Residential	GS <50	GS>50 Rims and Non RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$510,276,035	$206,483,542	$69,825,871	$146,219,442	$58,438,115	$23,587,823	$4,096,188	$1,625,054
mi	Miscellaneous Revenue (mi)	$26,335,129	$14,156,980	$5,214,357	$4,943,117	$1,102,861	$402,786	$426,389	$88,639
	Total Revenue	**$536,611,164**	**$220,640,522**	**$75,040,228**	**$151,162,559**	**$59,540,976**	**$23,990,609**	**$4,522,577**	**$1,713,693**
	Expenses								
di	Distribution Costs (di)	$94,406,121	$38,625,800	$12,960,894	$24,975,110	$10,087,154	$4,564,436	$2,629,359	$563,367
cu	Customer Related Costs (cu)	$50,849,608	$31,424,030	$11,114,748	$6,966,346	$659,668	$63,072	$515,691	$106,052
ad	General and Administration (ad)	$48,663,412	$23,569,439	$7,713,646	$10,707,644	$3,600,274	$1,543,228	$1,263,820	$265,360
dep	Depreciation and Amortization (dep)	$152,128,269	$77,086,249	$20,779,296	$32,691,880	$10,430,067	$4,310,869	$5,668,740	$1,161,168
INPUT	PILs (INPUT)	$40,598,137	$19,899,467	$5,578,797	$8,923,295	$3,035,112	$1,293,069	$1,550,113	$318,283
INT	Interest	$68,182,725	$33,420,250	$9,369,336	$14,986,268	$5,097,333	$2,171,651	$2,603,345	$534,542
	Total Expenses	**$454,828,271**	**$224,025,236**	**$67,516,718**	**$99,250,543**	**$32,909,609**	**$13,946,325**	**$14,231,069**	**$2,948,772**
	Direct Allocation	**$16,662,397**	**$1,134,282**	**$275,428**	**$3,453,897**	**$6,033,195**	**$5,765,595**	**$0**	**$0**
NI	Allocated Net Income (NI)	$65,120,495	$31,919,276	$8,948,540	$14,313,203	$4,868,401	$2,074,117	$2,486,423	$510,534
	Revenue Requirement (includes NI)	**$536,611,164**	$257,078,794	$76,740,686	$117,017,643	$43,811,206	$21,786,037	$16,717,492	$3,459,306
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$3,319,383,687	$1,637,287,841	$463,575,867	$726,119,685	$237,779,336	$99,478,105	$128,745,464	$26,397,389
gp	General Plant - Gross	$515,626,311	$252,800,034	$71,760,343	$114,124,742	$37,553,874	$15,727,829	$19,627,858	$4,031,629
accum dep	Accumulated Depreciation	($1,923,321,135)	($952,829,633)	($269,284,137)	($417,125,990)	($136,101,907)	($56,894,876)	($75,602,873)	($15,481,720)
co	Capital Contribution	($219,874,258)	($107,980,509)	($33,240,195)	($50,975,279)	($13,114,883)	($4,680,089)	($8,195,617)	($1,687,687)
	Total Net Plant	**$1,691,814,605**	**$829,277,734**	**$232,811,879**	**$372,143,158**	**$126,116,421**	**$53,630,970**	**$64,574,833**	**$13,259,611**
	Directly Allocated Net Fixed Assets	**$20,390,973**	**$0**	**$0**	**$734,075**	**$2,650,827**	**$17,006,071**	**$0**	**$0**
COP	Cost of Power (COP)	$1,922,552,889	$413,436,084	$193,638,087	$740,618,986	$382,451,685	$179,766,606	$8,284,331	$4,357,110
	OM&A Expenses	$193,919,141	$93,619,269	$31,789,289	$42,649,099	$14,347,096	$6,170,737	$4,408,871	$934,779

	Directly Allocated Expenses	**$13,987,050**	$1,134,282	$275,428	$3,357,585	$5,685,400	$3,534,355	$0	$0
	Subtotal	***$2,130,459,080***	***$508,189,636***	***$225,702,804***	***$786,625,670***	***$402,484,181***	***$189,471,699***	***$12,693,201***	***$5,291,889***
0.12573322	**Working Capital**	**$267,869,490**	**$63,896,322**	**$28,378,341**	$0 **$98,904,982**	**$50,605,634**	**$23,822,888**	**$1,595,957**	**$665,366**
	Total Rate Base	**$1,980,075,068**	**$893,174,055**	**$261,190,220**	**$471,782,215**	**$179,372,882**	**$94,459,928**	**$66,170,790**	**$13,924,977**
	Equity Component of Rate Base	**$742,528,150**	**$334,940,271**	**$97,946,333**	**$176,918,331**	**$67,264,831**	**$35,422,473**	**$24,814,046**	**$5,221,866**
	Net Income on Allocated Assets	**$65,120,495**	**($4,518,996)**	**$7,248,082**	**$48,458,118**	**$20,598,172**	**$4,278,689**	**($9,708,492)**	**($1,235,079)**
	Net Income on Direct Allocation Assets	**$404,401**	**$0**	**$0**	**$14,558**	**$52,572**	**$337,270**	**$0**	**$0**
	Net Income	**$65,524,896**	**($4,518,996)**	**$7,248,082**	**$48,472,677**	**$20,650,744**	**$4,615,960**	**($9,708,492)**	**($1,235,079)**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	**100.00%**	85.83%	97.78%	129.18%	135.90%	110.12%	27.05%	49.54%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	($36,438,272)	($1,700,458)	$34,144,915	$15,729,770	$2,204,572	($12,194,915)	($1,745,613)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.82%	-1.35%	7.40%	27.40%	30.70%	13.03%	-39.12%	-23.65%

Ontario

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O1 Revenue to Cost Summary Worksheet

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	Residential	GS <50	GS>50 Rims and Non RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$545,873,066	$229,820,728	$73,638,899	$149,951,706	$60,621,748	$24,758,695	$5,206,112	$1,875,178
mi	Miscellaneous Revenue (mi)	$21,732,002	$12,121,105	$4,491,369	$3,867,876	$744,744	$248,796	$221,954	$36,160
	Total Revenue	**$567,605,068**	**$241,941,833**	**$78,130,267**	**$153,819,582**	**$61,366,491**	**$25,007,491**	**$5,428,066**	**$1,911,338**
	Expenses								
di	Distribution Costs (di)	$100,603,212	$42,714,261	$13,115,778	$26,002,274	$10,695,536	$4,856,593	$2,748,806	$469,966
cu	Customer Related Costs (cu)	$53,491,902	$33,432,643	$11,388,631	$7,304,360	$713,275	$66,263	$511,181	$75,549
ad	General and Administration (ad)	$50,136,382	$24,911,367	$7,602,828	$10,869,950	$3,714,100	$1,592,202	$1,242,271	$203,664
dep	Depreciation and Amortization (dep)	$159,189,754	$81,917,188	$21,000,834	$33,823,442	$11,147,025	$4,636,044	$5,760,276	$904,944
INPUT	PILs (INPUT)	$39,230,446	$19,794,955	$5,102,365	$8,554,631	$2,942,593	$1,247,248	$1,371,938	$216,715
INT	Interest	$71,040,334	$35,845,634	$9,239,603	$15,491,128	$5,328,586	$2,258,575	$2,484,370	$392,438
	Total Expenses	**$473,692,030**	**$238,616,048**	**$67,450,039**	**$102,045,786**	**$34,541,115**	**$14,656,924**	**$14,118,843**	**$2,263,275**
	Direct Allocation	**$16,924,189**	**$1,193,642**	**$289,951**	**$3,412,444**	**$6,083,015**	**$5,945,137**	**$0**	**$0**
NI	Allocated Net Income (NI)	$76,988,850	$38,847,145	$10,013,275	$16,788,268	$5,774,772	$2,447,695	$2,692,397	$425,298
	Revenue Requirement (includes NI)	**$567,605,068**	$278,656,836	$77,753,265	$122,246,497	$46,398,902	$23,049,756	$16,811,240	$2,688,573
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$3,611,105,939	$1,830,932,057	$479,918,804	$779,670,376	$259,264,906	$108,061,804	$132,396,045	$20,861,947
gp	General Plant - Gross	$558,181,412	$281,622,790	$73,555,792	$122,583,197	$40,753,068	$16,957,007	$19,603,947	$3,105,611
accum dep	Accumulated Depreciation	($2,077,242,949)	($1,057,042,483)	($277,790,060)	($442,816,040)	($147,276,902)	($61,464,541)	($78,525,085)	($12,327,838)
co	Capital Contribution	($243,697,589)	($122,879,906)	($34,941,982)	($56,074,261)	($14,500,885)	($5,073,485)	($8,805,846)	($1,421,223)
	Total Net Plant	**$1,848,346,813**	**$932,632,459**	**$240,742,554**	**$403,363,272**	**$138,240,186**	**$58,480,785**	**$64,669,061**	**$10,218,497**
	Directly Allocated Net Fixed Assets	**$21,890,138**	**$0**	**$0**	**$788,045**	**$2,845,717**	**$18,256,376**	**$0**	**$0**
COP	Cost of Power (COP)	$1,923,661,344	$422,313,321	$193,626,677	$731,506,975	$383,174,890	$180,361,580	$8,306,466	$4,371,435
	OM&A Expenses	$204,231,496	$101,058,270	$32,107,237	$44,176,584	$15,122,910	$6,515,058	$4,502,258	$749,179
	Directly Allocated Expenses	$14,085,567	$1,193,642	$289,951	$3,310,254	$5,713,994	$3,577,726	$0	$0

	Subtotal	***$2,141,978,407***	***$524,565,234***	***$226,023,864***	***$778,993,813***	***$404,011,794***	***$190,454,364***	***$12,808,724***	***$5,120,614***
					$0				
0.12584212	**Working Capital**	**$269,551,096**	**$66,012,399**	**$28,443,321**	**$98,030,230**	**$50,841,699**	**$23,967,180**	**$1,611,877**	**$644,389**
	Total Rate Base	**$2,139,788,047**	**$998,644,858**	**$269,185,875**	**$502,181,546**	**$191,927,602**	**$100,704,341**	**$66,280,938**	**$10,862,886**
	Equity Component of Rate Base	**$855,915,219**	**$399,457,943**	**$107,674,350**	**$200,872,619**	**$76,771,041**	**$40,281,736**	**$26,512,375**	**$4,345,154**
	Net Income on Allocated Assets	**$76,988,850**	**$2,132,143**	**$10,390,277**	**$48,361,352**	**$20,742,362**	**$4,405,430**	**($8,690,777)**	**($351,937)**
	Net Income on Direct Allocation Assets	**$469,545**	**$0**	**$0**	**$16,904**	**$61,041**	**$391,600**	**$0**	**$0**
	Net Income	**$77,458,394**	**$2,132,143**	**$10,390,277**	**$48,378,256**	**$20,803,402**	**$4,797,030**	**($8,690,777)**	**($351,937)**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	**100.00%**	86.82%	100.48%	125.83%	132.26%	108.49%	32.29%	71.09%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	($36,715,002)	$377,002	$31,573,084	$14,967,590	$1,957,735	($11,383,174)	($777,235)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.05%	0.53%	9.65%	24.08%	27.10%	11.91%	-32.78%	-8.10%

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O1 Revenue to Cost Summary Worksheet

Ontario

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	Residential	GS <50	GS>50 Rims and Non RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$574,181,854	$252,382,804	$76,988,383	$149,446,767	$61,408,992	$25,459,105	$6,395,876	$2,099,927
mi	Miscellaneous Revenue (mi)	$24,283,140	$13,595,205	$4,802,304	$4,304,624	$928,157	$327,011	$280,188	$45,651
	Total Revenue	**$598,464,994**	**$265,978,009**	**$81,790,687**	**$153,751,391**	**$62,337,149**	**$25,786,116**	**$6,676,064**	**$2,145,578**
	Expenses								
di	Distribution Costs (di)	$103,914,007	$44,587,311	$14,130,351	$25,884,072	$11,103,292	$5,021,588	$2,719,869	$467,523
cu	Customer Related Costs (cu)	$56,439,851	$35,993,940	$11,408,978	$7,536,207	$747,269	$69,124	$596,705	$87,628
ad	General and Administration (ad)	$51,064,651	$25,723,351	$7,799,973	$10,704,696	$3,796,873	$1,623,272	$1,216,456	$200,029
dep	Depreciation and Amortization (dep)	$172,587,383	$89,565,388	$23,388,439	$35,541,238	$12,217,280	$5,091,985	$5,858,578	$924,475
INPUT	PILs (INPUT)	$37,868,814	$19,203,534	$5,057,353	$8,050,537	$2,897,619	$1,231,692	$1,232,139	$195,940
INT	Interest	$76,396,159	$38,741,014	$10,202,652	$16,241,070	$5,845,627	$2,484,804	$2,485,705	$395,287
	Total Expenses	**$498,270,865**	**$253,814,538**	**$71,987,746**	**$103,957,820**	**$36,607,960**	**$15,522,466**	**$14,109,452**	**$2,270,882**
	Direct Allocation	**$17,226,798**	**$1,283,551**	**$312,079**	**$3,358,217**	**$6,129,367**	**$6,143,584**	**$0**	**$0**
NI	Allocated Net Income (NI)	$82,967,331	$42,073,300	$11,080,227	$17,638,037	$6,348,436	$2,698,533	$2,699,511	$429,288
	Revenue Requirement (includes NI)	**$598,464,994**	$297,171,389	$83,380,052	$124,954,074	$49,085,763	$24,364,582	$16,808,963	$2,700,170
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$3,874,149,534	$1,980,487,144	$531,328,405	$808,802,350	$280,799,655	$117,257,102	$134,236,353	$21,238,525
gp	General Plant - Gross	$608,985,853	$308,914,029	$82,648,824	$130,153,284	$45,240,440	$18,866,818	$19,977,723	$3,184,735
accum dep	Accumulated Depreciation	($2,242,786,453)	($1,152,962,268)	($309,927,137)	($460,145,215)	($159,608,691)	($66,716,306)	($80,719,642)	($12,707,195)
co	Capital Contribution	($263,620,895)	($133,993,586)	($39,591,586)	($58,333,179)	($15,659,018)	($5,447,674)	($9,119,696)	($1,476,156)
	Total Net Plant	**$1,976,728,039**	**$1,002,445,320**	**$264,458,506**	**$420,477,239**	**$150,772,386**	**$63,959,940**	**$64,374,738**	**$10,239,910**
	Directly Allocated Net Fixed Assets	**$23,580,522**	**$0**	**$0**	**$848,899**	**$3,065,468**	**$19,666,155**	**$0**	**$0**
COP	Cost of Power (COP)	$1,925,554,529	$414,806,401	$196,793,072	$737,997,033	$382,540,788	$181,067,497	$8,218,720	$4,131,019
	OM&A Expenses	$211,418,509	$106,304,602	$33,339,302	$44,124,975	$15,647,434	$6,713,985	$4,533,030	$755,180
	Directly Allocated Expenses	$14,186,238	$1,283,551	$312,079	$3,248,757	$5,734,094	$3,607,757	$0	$0

	Subtotal	***$2,151,159,275***	***$522,394,555***	***$230,444,453***	***$785,370,765***	***$403,922,316***	***$191,389,239***	***$12,751,750***	***$4,886,199***
					$0				
0.1260111	**Working Capital**	**$271,069,936**	**$65,827,510**	**$29,038,558**	**$98,965,430**	**$50,898,693**	**$24,117,168**	**$1,606,862**	**$615,715**
	Total Rate Base	**$2,271,378,497**	**$1,068,272,830**	**$293,497,064**	**$520,291,568**	**$204,736,547**	**$107,743,263**	**$65,981,600**	**$10,855,625**
	Equity Component of Rate Base	**$908,551,399**	**$427,309,132**	**$117,398,826**	**$208,116,627**	**$81,894,619**	**$43,097,305**	**$26,392,640**	**$4,342,250**
	Net Income on Allocated Assets	**$82,967,331**	**$10,879,920**	**$9,490,862**	**$46,435,354**	**$19,599,821**	**$4,120,066**	**($7,433,388)**	**($125,304)**
	Net Income on Direct Allocation Assets	**$508,084**	**$0**	**$0**	**$18,291**	**$66,051**	**$423,742**	**$0**	**$0**
	Net Income	**$83,475,416**	**$10,879,920**	**$9,490,862**	**$46,453,645**	**$19,665,872**	**$4,543,808**	**($7,433,388)**	**($125,304)**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	**100.00%**	89.50%	98.09%	123.05%	127.00%	105.83%	39.72%	79.46%
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	($31,193,380)	($1,589,365)	$28,797,317	$13,251,386	$1,421,533	($10,132,899)	($554,592)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.19%	2.55%	8.08%	22.32%	24.01%	10.54%	-28.16%	-2.89%

Ontario

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	4	5	6	7	9
	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$6.12	$12.50	$32.46	$81.59	$149.08	$184.45	$0.48	$0.50
Customer Unit Cost per month - Directly Related	$7.68	$16.51	$48.78	$101.99	$186.03	$238.01	$0.68	$0.69
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.33	$34.06	$104.55	$117.34	$292.94	$501.89	$15.54	$9.32
Fixed Charge per approved 2007 Rates	$12.00	$16.07	$25.58	$25.82	$717.42	$2,758.30	$0.26	$1.99

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	4	5	6	7	9
	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
General Plant - Gross Assets	$515,626,311	$252,800,034	$71,760,343	$20,401,261	$93,723,481	$37,553,874	$15,727,829	$19,627,858	$4,031,629
General Plant - Accumulated Depreciation	($327,142,327)	($160,390,557)	($45,528,797)	($12,943,707)	($59,463,447)	($23,826,290)	($9,978,619)	($12,453,017)	($2,557,892)
General Plant - Net Fixed Assets	$188,483,984	$92,409,477	$26,231,546	$7,457,554	$34,260,035	$13,727,585	$5,749,210	$7,174,841	$1,473,737
General Plant - Depreciation	$30,913,004	$15,155,954	$4,302,201	$1,223,103	$5,618,942	$2,251,443	$942,920	$1,176,736	$241,706
Total Net Fixed Assets Excluding General Plant	$1,503,330,620	$736,868,257	$206,580,333	$58,709,267	$271,716,303	$112,388,836	$47,881,760	$57,399,991	$11,785,874
Total Administration and General Expense	$48,663,412	$23,569,439	$7,713,646	$2,030,534	$8,677,110	$3,600,274	$1,543,228	$1,263,820	$265,360
Total O&M	$145,255,728	$70,049,830	$24,075,643	$6,188,069	$25,753,386	$10,746,822	$4,627,509	$3,145,050	$669,419

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 196,585,247	$ 132,831,145	$ 16,339,561	$ 4,627,463	$ 36,407,215	$ 5,749,198	$ 630,665	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (93,833,313)	$ (63,402,450)	$ (7,799,136)	$ (2,208,763)	$ (17,377,751)	$ (2,744,185)	$ (301,027)	$ -	$ -
Meter Net Fixed Assets	$ 102,751,935	$ 69,428,695	$ 8,540,425	$ 2,418,700	$ 19,029,463	$ 3,005,013	$ 329,639	$ -	$ -
Misc Revenue									
CWNB	$ (2,772,380)	$ (1,620,086)	$ (702,828)	$ (78,464)	$ (347,335)	$ (19,405)	$ (3,859)	$ (89)	$ (315)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,944)	$ (192,582)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	$ (7,772,380)	$ (4,360,788)	$ (1,803,980)	$ (813,408)	$ (539,917)	$ (216,814)	$ (37,070)	$ (89)	$ (315)
Operation									
CWMC	$ 6,012,352	$ 4,062,500	$ 499,728	$ 141,526	$ 1,113,476	$ 175,833	$ 19,288	$ -	$ -
CCA	$ 4,652,874	$ 3,576,982	$ 387,943	$ 12,374	$ 54,777	$ 3,060	$ 284	$ 514,744	$ 102,709
Sub-total	$ 10,665,225	$ 7,639,482	$ 887,671	$ 153,900	$ 1,168,253	$ 178,893	$ 19,572	$ 514,744	$ 102,709
Maintenance									
1860	$ 795,836	$ 537,740	$ 66,147	$ 18,733	$ 147,387	$ 23,274	$ 2,553	$ -	$ -
Billing and Collection									
CWMR	$ 2,970,310	$ 2,122,450	$ 821,157	$ 26,703	$ -	$ -	$ -	$ -	$ -
CWNB	$ 29,149,232	$ 17,033,833	$ 7,389,644	$ 824,979	$ 3,651,931	$ 204,023	$ 40,573	$ 938	$ 3,312
Sub-total	$ 32,119,542	$ 19,156,283	$ 8,210,800	$ 851,681	$ 3,651,931	$ 204,023	$ 40,573	$ 938	$ 3,312
Total Operation, Maintenance and Billing	$ 43,580,604	$ 27,333,506	$ 9,164,619	$ 1,024,315	$ 4,967,571	$ 406,191	$ 62,698	$ 515,682	$ 106,021
Amortization Expense - Meters	$ 15,082,855	$ 10,191,370	$ 1,253,641	$ 355,039	$ 2,793,316	$ 441,103	$ 48,387	$ -	$ -
Allocated PILs	$ 2,465,253	$ 1,666,021	$ 204,651	$ 57,956	$ 456,358	$ 72,319	$ 7,948	$ -	$ -
Allocated Debt Return	$ 4,140,281	$ 2,798,006	$ 343,703	$ 97,335	$ 766,433	$ 121,456	$ 13,348	$ -	$ -
Allocated Equity Return	$ 3,954,332	$ 2,672,342	$ 328,266	$ 92,963	$ 732,011	$ 116,001	$ 12,748	$ -	$ -
Total	**$ 61,450,944**	**$ 40,300,457**	**$ 9,490,900**	**$ 814,201**	**$ 9,175,773**	**$ 940,255**	**$ 108,060**	**$ 515,593**	**$ 105,706**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 196,585,247	$ 132,831,145	$ 16,339,561	$ 4,627,463	$ 36,407,215	$ 5,749,198	$ 630,665	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (93,833,313)	$ (63,402,450)	$ (7,799,136)	$ (2,208,763)	$ (17,377,751)	$ (2,744,185)	$ (301,027)	$ -	$ -
Meter Net Fixed Assets	$ 102,751,935	$ 69,428,695	$ 8,540,425	$ 2,418,700	$ 19,029,463	$ 3,005,013	$ 329,639	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 12,904,641	$ 8,706,942	$ 1,084,462	$ 307,236	$ 2,399,378	$ 367,043	$ 39,580	$ -	$ -

Meter Net Fixed Assets Including General Plant	$ 115,656,576	$ 78,135,637	$ 9,624,887	$ 2,725,936	$ 21,428,841	$ 3,372,056	$ 369,219	$ -	$ -
Misc Revenue									
CWNB	$ (2,772,380)	$ (1,620,086)	$ (702,828)	$ (78,464)	$ (347,335)	$ (19,405)	$ (3,859)	$ (89)	$ (315)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,944)	$ (192,582)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	*$ (7,772,380)*	*$ (4,360,788)*	*$ (1,803,980)*	*$ (813,408)*	*$ (539,917)*	*$ (216,814)*	*$ (37,070)*	*$ (89)*	*$ (315)*
Operation									
CWMC	$ 6,012,352	$ 4,062,500	$ 499,728	$ 141,526	$ 1,113,476	$ 175,833	$ 19,288	$ -	$ -
CCA	$ 4,652,874	$ 3,576,982	$ 387,943	$ 12,374	$ 54,777	$ 3,060	$ 284	$ 514,744	$ 102,709
Sub-total	*$ 10,665,225*	*$ 7,639,482*	*$ 887,671*	*$ 153,900*	*$ 1,168,253*	*$ 178,893*	*$ 19,572*	*$ 514,744*	*$ 102,709*
Maintenance									
1860	$ 795,836	$ 537,740	$ 66,147	$ 18,733	$ 147,387	$ 23,274	$ 2,553	$ -	$ -
Billing and Collection									
CWMR	$ 2,970,310	$ 2,122,450	$ 821,157	$ 26,703	$ -	$ -	$ -	$ -	$ -
CWNB	$ 29,149,232	$ 17,033,833	$ 7,389,644	$ 824,979	$ 3,651,931	$ 204,023	$ 40,573	$ 938	$ 3,312
Sub-total	*$ 32,119,542*	*$ 19,156,283*	*$ 8,210,800*	*$ 851,681*	*$ 3,651,931*	*$ 204,023*	*$ 40,573*	*$ 938*	*$ 3,312*
Total Operation, Maintenance and Billing	$ 43,580,604	$ 27,333,506	$ 9,164,619	$ 1,024,315	$ 4,967,571	$ 406,191	$ 62,698	$ 515,682	$ 106,021
Amortization Expense - Meters	$ 15,082,855	$ 10,191,370	$ 1,253,641	$ 355,039	$ 2,793,316	$ 441,103	$ 48,387	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 2,116,473	$ 1,428,014	$ 177,861	$ 50,389	$ 393,519	$ 60,198	$ 6,491	$ -	$ -
Admin and General	$ 14,549,169	$ 9,196,816	$ 2,936,272	$ 336,116	$ 1,673,728	$ 136,077	$ 20,909	$ 207,224	$ 42,027
Allocated PILs	$ 2,774,863	$ 1,874,954	$ 230,638	$ 65,318	$ 513,899	$ 81,152	$ 8,902	$ -	$ -
Allocated Debt Return	$ 4,660,257	$ 3,148,900	$ 387,346	$ 109,699	$ 863,071	$ 136,291	$ 14,951	$ -	$ -
Allocated Equity Return	$ 4,450,955	$ 3,007,476	$ 369,950	$ 104,772	$ 824,308	$ 130,170	$ 14,279	$ -	$ -
Total	**$ 79,442,795**	**$ 51,820,247**	**$ 12,716,346**	**$ 1,232,240**	**$ 11,489,496**	**$ 1,174,367**	**$ 139,548**	**$ 722,817**	**$ 147,734**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
	Distribution Plant									
	CDMPP	$ 15,443,114	$ 7,447,469	$ 2,559,644	$ 657,895	$ 2,738,016	$ 1,142,567	$ 491,982	$ 334,371	$ 71,170
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 463,969,681	$ 356,685,217	$ 38,684,432	$ 1,233,921	$ 5,462,195	$ 305,157	$ 28,319	$ 51,328,606	$ 10,241,833
	SNCP	$ 219,670,875	$ 170,871,178	$ 18,531,899	$ 148,074	$ 620,561	$ 3,562	$ 88	$ 24,589,131	$ 4,906,382
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 184,026,165	$ 141,964,656	$ 15,396,831	$ 410,080	$ 1,718,599	$ 29,594	$ 690	$ 20,429,352	$ 4,076,363
	CWCS	$ 316,671,669	$ 220,717,657	$ 47,876,037	$ 1,912,698	$ 8,015,909	$ 46,011	$ 3,425	$ 31,762,263	$ 6,337,670
	CWMC	$ 196,585,247	$ 132,831,145	$ 16,339,561	$ 4,627,463	$ 36,407,215	$ 5,749,198	$ 630,665	$ -	$ -
	Sub-total	*$ 1,396,366,750*	*$ 1,030,517,321*	*$ 139,388,405*	*$ 8,990,130*	*$ 54,962,495*	*$ 7,276,088*	*$ 1,155,170*	*$ 128,443,723*	*$ 25,633,418*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (754,033,156)	$ (559,594,426)	$ (74,385,471)	$ (4,344,007)	$ (26,532,933)	$ (3,235,533)	$ (447,233)	$ (71,271,104)	$ (14,222,447)
	Customer Related Net Fixed Assets	$ 642,333,594	$ 470,922,895	$ 65,002,933	$ 4,646,123	$ 28,429,561	$ 4,040,555	$ 707,936	$ 57,172,619	$ 11,410,971

Allocated General Plant Net Fixed Assets	$ 80,638,353	$ 59,057,692	$ 8,254,065	$ 590,174	$ 3,584,613	$ 493,528	$ 85,003	$ 7,146,420	$ 1,426,858
Customer Related NFA Including General Plant	$ 722,971,947	$ 529,980,587	$ 73,256,998	$ 5,236,297	$ 32,014,174	$ 4,534,083	$ 792,939	$ 64,319,039	$ 12,837,829
Misc Revenue									
CWNB	$ (10,176,406)	$ (5,946,750)	$ (2,579,828)	$ (288,012)	$ (1,274,940)	$ (71,227)	$ (14,165)	$ (328)	$ (1,156)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,944)	$ (192,582)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	*$ (15,176,406)*	*$ (8,687,452)*	*$ (3,680,980)*	*$ (1,022,956)*	*$ (1,467,522)*	*$ (268,636)*	*$ (47,376)*	*$ (328)*	*$ (1,156)*
Operating and Maintenance									
1815-1855	$ 15,186,085	$ 11,327,844	$ 1,544,673	$ 55,573	$ 253,980	$ 36,842	$ 16,688	$ 1,625,847	$ 324,639
1830 & 1835	$ 1,799,585	$ 1,391,149	$ 150,878	$ 3,106	$ 13,615	$ 641	$ 59	$ 200,193	$ 39,945
1850	$ 522,816	$ 403,320	$ 43,742	$ 1,165	$ 4,883	$ 84	$ 2	$ 58,040	$ 11,581
1840 & 1845	$ 952,222	$ 734,309	$ 79,640	$ 2,036	$ 8,973	$ 466	$ 43	$ 105,670	$ 21,085
CWMC	$ 6,012,352	$ 4,062,500	$ 499,728	$ 141,526	$ 1,113,476	$ 175,833	$ 19,288	$ -	$ -
CCA	$ 4,652,874	$ 3,576,982	$ 387,943	$ 12,374	$ 54,777	$ 3,060	$ 284	$ 514,744	$ 102,709
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 2,435,827	$ 1,882,989	$ 204,220	$ 4,204	$ 18,428	$ 867	$ 79	$ 270,971	$ 54,068
1855	$ 284,291	$ 198,148	$ 42,981	$ 1,717	$ 7,196	$ 41	$ 3	$ 28,514	$ 5,690
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 2,312,248	$ 1,783,098	$ 193,387	$ 4,944	$ 21,788	$ 1,131	$ 104	$ 256,596	$ 51,200
1860	$ 795,836	$ 537,740	$ 66,147	$ 18,733	$ 147,387	$ 23,274	$ 2,553	$ -	$ -
Sub-total	*$ 34,954,135*	*$ 25,898,080*	*$ 3,213,338*	*$ 245,379*	*$ 1,644,504*	*$ 242,240*	*$ 39,104*	*$ 3,060,575*	*$ 610,917*
Billing and Collection									
CWNB	$ 29,418,236	$ 17,191,030	$ 7,457,839	$ 832,592	$ 3,685,633	$ 205,906	$ 40,947	$ 947	$ 3,343
CWMR	$ 2,970,310	$ 2,122,450	$ 821,157	$ 26,703	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,000,000	$ 3,933,327	$ 1,881,934	$ 801,603	$ 131,541	$ 251,595	$ -	$ -	$ -
Sub-total	*$ 39,388,546*	*$ 23,246,807*	*$ 10,160,930*	*$ 1,660,898*	*$ 3,817,174*	*$ 457,501*	*$ 40,947*	*$ 947*	*$ 3,343*
Sub Total Operating, Maintenance and Biling	*$ 74,342,682*	*$ 49,144,887*	*$ 13,374,268*	*$ 1,906,277*	*$ 5,461,677*	*$ 699,741*	*$ 80,051*	*$ 3,061,522*	*$ 614,259*
Amortization Expense - Customer Related	$ 58,224,585	$ 41,944,984	$ 5,775,062	$ 572,651	$ 3,759,433	$ 649,433	$ 140,025	$ 4,486,717	$ 896,281
Amortization Expense - General Plant assigned to Meters	$ 13,225,388	$ 9,685,972	$ 1,353,738	$ 96,794	$ 587,908	$ 80,943	$ 13,941	$ 1,172,075	$ 234,017
Admin and General	$ 25,021,223	$ 16,535,621	$ 4,285,010	$ 625,520	$ 1,840,208	$ 234,419	$ 26,696	$ 1,230,255	$ 243,495
Allocated PILs	$ 17,346,515	$ 12,717,490	$ 1,755,434	$ 125,471	$ 767,753	$ 109,117	$ 19,118	$ 1,543,973	$ 308,159
Allocated Debt Return	$ 29,132,683	$ 21,358,446	$ 2,948,172	$ 210,722	$ 1,289,407	$ 183,257	$ 32,108	$ 2,593,032	$ 517,538
Allocated Equity Return	$ 27,824,273	$ 20,399,193	$ 2,815,763	$ 201,258	$ 1,231,497	$ 175,027	$ 30,666	$ 2,476,574	$ 494,295
PLCC Adjustment for Line Transformer	$ 4,208,675	$ 3,651,833	$ 396,272	$ 10,557	$ 44,228	$ 760	$ 18	$ -	$ 105,008
PLCC Adjustment for Primary Costs	$ 7,430,190	$ 6,423,161	$ 696,257	$ 22,019	$ 97,461	$ 5,402	$ 500	$ -	$ 185,390
PLCC Adjustment for Secondary Costs	$ 9,385,791	$ 7,505,793	$ 719,412	$ 22,033	$ 97,525	$ 5,395	$ -	$ -	$ 1,035,634
Total	**$ 208,916,285**	**$ 145,518,355**	**$ 26,814,526**	**$ 2,661,128**	**$ 13,231,146**	**$ 1,851,744**	**$ 294,712**	**$ 16,563,819**	**$ 1,980,855**

Ontario

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	4	5	6	7	9
	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$6.55	$13.80	$7.12	$88.18	$168.16	$206.52	$0.48	$0.50
Customer Unit Cost per month - Directly Related	$8.27	$18.10	$24.81	$111.67	$214.10	$270.14	$0.66	$0.69
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.94	$35.75	$128.82	$127.47	$332.70	$590.54	$15.62	$12.34
2007 Approved Fixed Charge	$12.00	$16.07	$25.58	$25.82	$717.42	$2,758.30	$0.26	$1.99

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	4	5	6	7	9
	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
General Plant - Gross Assets	$558,181,412	$281,622,790	$73,555,792	$12,544,073	$110,039,124	$40,753,068	$16,957,007	$19,603,947	$3,105,611
General Plant - Accumulated Depreciation	($357,714,605)	($180,480,007)	($47,138,763)	($8,038,960)	($70,519,370)	($26,116,899)	($10,867,021)	($12,563,331)	($1,990,253)
General Plant - Net Fixed Assets	$200,466,807	$101,142,783	$26,417,029	$4,505,113	$39,519,753	$14,636,169	$6,089,986	$7,040,615	$1,115,358
General Plant - Depreciation	$33,705,954	$17,005,878	$4,441,689	$757,478	$6,644,746	$2,460,886	$1,023,954	$1,183,790	$187,533
Total Net Fixed Assets Excluding General Plant	$1,647,880,007	$831,489,676	$214,325,525	$36,340,676	$322,997,729	$123,604,017	$52,390,799	$57,628,446	$9,103,139
Total Administration and General Expense	$50,136,382	$24,911,367	$7,602,828	$1,245,816	$9,624,133	$3,714,100	$1,592,202	$1,242,271	$203,664
Total O&M	$154,095,114	$76,146,904	$24,504,409	$3,971,964	$29,334,670	$11,408,810	$4,922,856	$3,259,987	$545,515

Below:

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 281,071,517	$ 188,368,869	$ 27,531,641	$ 3,047,005	$ 53,573,045	$ 7,717,059	$ 833,898	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (108,116,455)	$ (72,457,624)	$ (10,590,271)	$ (1,172,055)	$ (20,607,309)	$ (2,968,430)	$ (320,766)	$ -	$ -
Meter Net Fixed Assets	$ 172,955,062	$ 115,911,245	$ 16,941,370	$ 1,874,950	$ 32,965,735	$ 4,748,629	$ 513,132	$ -	$ -
Misc Revenue									
CWNB	$ (2,862,380)	$ (1,702,533)	$ (706,595)	$ (39,383)	$ (389,759)	$ (19,821)	$ (3,883)	$ (90)	$ (317)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,943)	$ (192,583)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	$ (7,862,380)	$ (4,443,235)	$ (1,807,747)	$ (774,326)	$ (582,342)	$ (217,230)	$ (37,094)	$ (90)	$ (317)
Operation									
CWMC	$ 7,580,042	$ 5,080,002	$ 742,484	$ 82,173	$ 1,444,778	$ 208,117	$ 22,489	$ -	$ -
CCA	$ 4,739,803	$ 3,703,111	$ 384,222	$ 6,119	$ 60,553	$ 3,079	$ 282	$ 510,233	$ 72,205
Sub-total	$ 12,319,845	$ 8,783,113	$ 1,126,705	$ 88,291	$ 1,505,331	$ 211,196	$ 22,770	$ 510,233	$ 72,205
Maintenance									
1860	$ 852,362	$ 571,237	$ 83,491	$ 9,240	$ 162,463	$ 23,402	$ 2,529	$ -	$ -
Billing and Collection									
CWMR	$ 2,621,397	$ 1,902,180	$ 707,451	$ 11,766	$ -	$ -	$ -	$ -	$ -
CWNB	$ 29,919,171	$ 17,795,810	$ 7,385,722	$ 411,649	$ 4,073,975	$ 207,177	$ 40,585	$ 939	$ 3,313
Sub-total	$ 32,540,568	$ 19,697,991	$ 8,093,173	$ 423,415	$ 4,073,975	$ 207,177	$ 40,585	$ 939	$ 3,313
Total Operation, Maintenance and Billing	$ 45,712,775	$ 29,052,340	$ 9,303,369	$ 520,947	$ 5,741,769	$ 441,776	$ 65,884	$ 511,172	$ 75,518
Amortization Expense - Meters	$ 13,483,431	$ 9,036,343	$ 1,320,735	$ 146,170	$ 2,569,981	$ 370,199	$ 40,003	$ -	$ -
Allocated PILs	$ 3,670,239	$ 2,460,195	$ 359,060	$ 39,713	$ 699,248	$ 101,080	$ 10,944	$ -	$ -
Allocated Debt Return	$ 6,646,242	$ 4,455,037	$ 650,203	$ 71,914	$ 1,266,230	$ 183,040	$ 19,818	$ -	$ -
Allocated Equity Return	$ 7,202,761	$ 4,828,077	$ 704,647	$ 77,936	$ 1,372,257	$ 198,367	$ 21,477	$ -	$ -
Total	**$ 68,853,068**	**$ 45,388,757**	**$ 10,530,267**	**$ 82,354**	**$ 11,067,143**	**$ 1,077,232**	**$ 121,032**	**$ 511,082**	**$ 75,201**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 281,071,517	$ 188,368,869	$ 27,531,641	$ 3,047,005	$ 53,573,045	$ 7,717,059	$ 833,898	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (108,116,455)	$ (72,457,624)	$ (10,590,271)	$ (1,172,055)	$ (20,607,309)	$ (2,968,430)	$ (320,766)	$ -	$ -
Meter Net Fixed Assets	$ 172,955,062	$ 115,911,245	$ 16,941,370	$ 1,874,950	$ 32,965,735	$ 4,748,629	$ 513,132	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 21,075,466	$ 14,099,497	$ 2,088,135	$ 232,435	$ 4,033,458	$ 562,294	$ 59,647	$ -	$ -

Meter Net Fixed Assets Including General Plant	$ 194,030,528	$ 130,010,742	$ 19,029,505	$ 2,107,385	$ 36,999,193	$ 5,310,923	$ 572,779	$ -	$ -
Misc Revenue									
CWNB	$ (2,862,380)	$ (1,702,533)	$ (706,595)	$ (39,383)	$ (389,759)	$ (19,821)	$ (3,883)	$ (90)	$ (317)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,943)	$ (192,583)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	*$ (7,862,380)*	*$ (4,443,235)*	*$ (1,807,747)*	*$ (774,326)*	*$ (582,342)*	*$ (217,230)*	*$ (37,094)*	*$ (90)*	*$ (317)*
Operation									
CWMC	$ 7,580,042	$ 5,080,002	$ 742,484	$ 82,173	$ 1,444,778	$ 208,117	$ 22,489	$ -	$ -
CCA	$ 4,739,803	$ 3,703,111	$ 384,222	$ 6,119	$ 60,553	$ 3,079	$ 282	$ 510,233	$ 72,205
Sub-total	*$ 12,319,845*	*$ 8,783,113*	*$ 1,126,705*	*$ 88,291*	*$ 1,505,331*	*$ 211,196*	*$ 22,770*	*$ 510,233*	*$ 72,205*
Maintenance									
1860	$ 852,362	$ 571,237	$ 83,491	$ 9,240	$ 162,463	$ 23,402	$ 2,529	$ -	$ -
Billing and Collection									
CWMR	$ 2,621,397	$ 1,902,180	$ 707,451	$ 11,766	$ -	$ -	$ -	$ -	$ -
CWNB	$ 29,919,171	$ 17,795,810	$ 7,385,722	$ 411,649	$ 4,073,975	$ 207,177	$ 40,585	$ 939	$ 3,313
Sub-total	*$ 32,540,568*	*$ 19,697,991*	*$ 8,093,173*	*$ 423,415*	*$ 4,073,975*	*$ 207,177*	*$ 40,585*	*$ 939*	*$ 3,313*
Total Operation, Maintenance and Billing	$ 45,712,775	$ 29,052,340	$ 9,303,369	$ 520,947	$ 5,741,769	$ 441,776	$ 65,884	$ 511,172	$ 75,518
Amortization Expense - Meters	$ 13,483,431	$ 9,036,343	$ 1,320,735	$ 146,170	$ 2,569,981	$ 370,199	$ 40,003	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 3,543,573	$ 2,370,652	$ 351,093	$ 39,081	$ 678,175	$ 94,543	$ 10,029	$ -	$ -
Admin and General	$ 14,826,206	$ 9,504,438	$ 2,886,497	$ 163,396	$ 1,883,762	$ 143,819	$ 21,309	$ 194,790	$ 28,194
Allocated PILs	$ 4,117,475	$ 2,759,454	$ 403,317	$ 44,636	$ 784,803	$ 113,049	$ 12,216	$ -	$ -
Allocated Debt Return	$ 7,456,117	$ 4,996,950	$ 730,345	$ 80,829	$ 1,421,157	$ 204,714	$ 22,121	$ -	$ -
Allocated Equity Return	$ 8,080,450	$ 5,415,366	$ 791,500	$ 87,598	$ 1,540,157	$ 221,856	$ 23,973	$ -	$ -
Total	**$ 89,357,646**	**$ 58,692,308**	**$ 13,979,109**	**$ 308,331**	**$ 14,037,462**	**$ 1,372,725**	**$ 158,442**	**$ 705,872**	**$ 103,395**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
	Distribution Plant									
	CDMPP	$ 15,880,934	$ 7,847,646	$ 2,525,407	$ 409,348	$ 3,023,210	$ 1,175,784	$ 507,346	$ 335,972	$ 56,220
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 494,713,410	$ 386,509,378	$ 40,102,851	$ 638,619	$ 6,320,226	$ 321,408	$ 29,382	$ 53,255,196	$ 7,536,350
	SNCP	$ 232,672,705	$ 183,876,425	$ 19,078,370	$ 76,206	$ 717,161	$ 3,726	$ 91	$ 25,335,414	$ 3,585,313
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 197,289,239	$ 154,660,301	$ 16,047,008	$ 213,658	$ 2,010,703	$ 31,336	$ 720	$ 21,309,870	$ 3,015,643
	CWCS	$ 324,780,992	$ 230,642,004	$ 47,861,203	$ 955,875	$ 8,995,572	$ 46,731	$ 3,427	$ 31,779,009	$ 4,497,171
	CWMC	$ 281,071,517	$ 188,368,869	$ 27,531,641	$ 3,047,005	$ 53,573,045	$ 7,717,059	$ 833,898	$ -	$ -
	Sub-total	*$ 1,546,408,796*	*$ 1,151,904,623*	*$ 153,146,479*	*$ 5,340,711*	*$ 74,639,916*	*$ 9,296,044*	*$ 1,374,864*	*$ 132,015,462*	*$ 18,690,698*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (820,274,841)	$ (616,096,123)	$ (80,521,534)	$ (2,350,681)	$ (31,771,788)	$ (3,699,406)	$ (574,521)	$ (74,687,521)	$ (10,573,268)
	Customer Related Net Fixed Assets	$ 726,133,954	$ 535,808,500	$ 72,624,945	$ 2,990,030	$ 42,868,128	$ 5,596,638	$ 800,343	$ 57,327,940	$ 8,117,430

Allocated General Plant Net Fixed Assets	$ 88,497,435	$ 65,175,990	$ 8,951,502	$ 370,671	$ 5,245,046	$ 662,708	$ 93,033	$ 7,003,902	$ 994,584
Customer Related NFA Including General Plant	$ 814,631,389	$ 600,984,490	$ 81,576,447	$ 3,360,700	$ 48,113,174	$ 6,259,346	$ 893,376	$ 64,331,842	$ 9,112,014
Misc Revenue									
CWNB	$ (10,394,581)	$ (6,182,658)	$ (2,565,963)	$ (143,016)	$ (1,415,389)	$ (71,978)	$ (14,100)	$ (326)	$ (1,151)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,943)	$ (192,583)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	*$ (15,394,581)*	*$ (8,923,360)*	*$ (3,667,115)*	*$ (877,959)*	*$ (1,607,972)*	*$ (269,387)*	*$ (47,311)*	*$ (326)*	*$ (1,151)*
Operating and Maintenance									
1815-1855	$ 16,214,344	$ 12,253,639	$ 1,597,716	$ 31,019	$ 325,650	$ 58,778	$ 27,768	$ 1,681,386	$ 238,387
1830 & 1835	$ 1,849,446	$ 1,452,761	$ 150,733	$ 1,550	$ 15,198	$ 651	$ 59	$ 200,169	$ 28,327
1850	$ 571,598	$ 448,091	$ 46,492	$ 619	$ 5,826	$ 91	$ 2	$ 61,740	$ 8,737
1840 & 1845	$ 1,219,891	$ 955,959	$ 99,187	$ 1,266	$ 12,480	$ 590	$ 54	$ 131,717	$ 18,640
CWMC	$ 7,580,042	$ 5,080,002	$ 742,484	$ 82,173	$ 1,444,778	$ 208,117	$ 22,489	$ -	$ -
CCA	$ 4,739,803	$ 3,703,111	$ 384,222	$ 6,119	$ 60,553	$ 3,079	$ 282	$ 510,233	$ 72,205
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 2,661,517	$ 2,090,651	$ 216,919	$ 2,230	$ 21,872	$ 936	$ 84	$ 288,060	$ 40,765
1855	$ 296,397	$ 210,485	$ 43,678	$ 872	$ 8,209	$ 43	$ 3	$ 29,002	$ 4,104
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 2,510,143	$ 1,967,055	$ 204,095	$ 2,605	$ 25,679	$ 1,213	$ 110	$ 271,031	$ 38,355
1860	$ 852,362	$ 571,237	$ 83,491	$ 9,240	$ 162,463	$ 23,402	$ 2,529	$ -	$ -
Sub-total	*$ 38,495,542*	*$ 28,732,990*	*$ 3,569,017*	*$ 137,694*	*$ 2,082,708*	*$ 296,899*	*$ 53,379*	*$ 3,173,337*	*$ 449,519*
Billing and Collection									
CWNB	$ 30,198,298	$ 17,961,834	$ 7,454,626	$ 415,490	$ 4,111,982	$ 209,110	$ 40,964	$ 947	$ 3,344
CWMR	$ 2,621,397	$ 1,902,180	$ 707,451	$ 11,766	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -
Sub-total	*$ 40,319,695*	*$ 24,078,293*	*$ 10,178,435*	*$ 1,286,116*	*$ 4,252,918*	*$ 478,676*	*$ 40,964*	*$ 947*	*$ 3,344*
Sub Total Operating, Maintenance and Biling	*$ 78,815,237*	*$ 52,811,284*	*$ 13,747,452*	*$ 1,423,810*	*$ 6,335,626*	*$ 775,575*	*$ 94,343*	*$ 3,174,285*	*$ 452,863*
Amortization Expense - Customer Related	$ 58,860,132	$ 42,874,516	$ 5,933,716	$ 271,661	$ 3,756,811	$ 641,721	$ 163,249	$ 4,569,741	$ 648,717
Amortization Expense - General Plant assigned to Meters	$ 14,879,723	$ 10,958,517	$ 1,505,082	$ 62,324	$ 881,888	$ 111,426	$ 15,642	$ 1,177,617	$ 167,227
Admin and General	$ 25,729,345	$ 17,277,147	$ 4,265,335	$ 446,582	$ 2,078,595	$ 252,486	$ 30,513	$ 1,209,613	$ 169,073
Allocated PILs	$ 17,286,792	$ 12,755,787	$ 1,728,954	$ 71,182	$ 1,020,545	$ 133,237	$ 19,053	$ 1,364,784	$ 193,249
Allocated Debt Return	$ 31,303,735	$ 23,098,778	$ 3,130,871	$ 128,901	$ 1,848,051	$ 241,272	$ 34,503	$ 2,471,415	$ 349,944
Allocated Equity Return	$ 33,924,932	$ 25,032,939	$ 3,393,033	$ 139,694	$ 2,002,796	$ 261,475	$ 37,392	$ 2,678,358	$ 379,246
PLCC Adjustment for Line Transformer	$ 4,541,535	$ 3,990,996	$ 414,316	$ 5,519	$ 51,911	$ 807	$ 19	$ -	$ 77,966
PLCC Adjustment for Primary Costs	$ 8,087,638	$ 7,081,875	$ 734,338	$ 11,595	$ 114,755	$ 5,789	$ 528	$ -	$ 138,758
PLCC Adjustment for Secondary Costs	$ 9,269,455	$ 8,111,691	$ 746,527	$ 11,394	$ 112,815	$ 5,679	$ -	$ -	$ 281,349
Total	**$ 223,506,686**	**$ 156,701,047**	**$ 28,142,146**	**$ 1,637,686**	**$ 16,036,859**	**$ 2,135,529**	**$ 346,839**	**$ 16,645,488**	**$ 1,861,093**

Ontario

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$6.96	$14.33	-$163.21	$94.47	$186.08	$226.97	$0.56	$0.58
Customer Unit Cost per month - Directly Related	$8.75	$18.70	-$145.92	$119.23	$235.89	$294.91	$0.77	$0.79
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$21.18	$36.02	$220.36	$134.70	$356.68	$638.15	$15.60	$12.21
2007 Approved Fixed Charge	$12.00	$16.07	$25.58	$25.82	$717.42	$2,758.30	$0.26	$1.99

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
General Plant - Gross Assets	$608,985,853	$308,914,029	$82,648,824	$3,899,540	$126,253,744	$45,240,440	$18,866,818	$19,977,723	$3,184,735
General Plant - Accumulated Depreciation	($392,984,547)	($199,345,255)	($53,334,097)	($2,516,412)	($81,472,780)	($29,194,100)	($12,174,943)	($12,891,821)	($2,055,141)
General Plant - Net Fixed Assets	$216,001,306	$109,568,775	$29,314,727	$1,383,129	$44,780,964	$16,046,340	$6,691,875	$7,085,902	$1,129,594
General Plant - Depreciation	$37,524,065	$19,034,449	$5,092,598	$240,279	$7,779,415	$2,787,594	$1,162,522	$1,230,973	$196,235
Total Net Fixed Assets Excluding General Plant	$1,760,726,733	$892,876,546	$235,143,779	$11,026,054	$363,287,092	$134,726,046	$57,268,065	$57,288,835	$9,110,316
Total Administration and General Expense	$51,064,651	$25,723,351	$7,799,973	$489,694	$10,215,002	$3,796,873	$1,623,272	$1,216,456	$200,029
Total O&M	$160,353,857	$80,581,251	$25,539,329	$1,724,361	$31,695,918	$11,850,560	$5,090,713	$3,316,574	$555,151

Below: Grouping to avoid disclosure

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 322,015,614	$ 217,866,269	$ 30,962,573	$ 827,455	$ 62,917,004	$ 8,532,216	$ 910,097	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (122,815,946)	$ (83,093,647)	$ (11,809,048)	$ (315,589)	$ (23,996,387)	$ (3,254,166)	$ (347,109)	$ -	$ -
Meter Net Fixed Assets	$ 199,199,669	$ 134,772,622	$ 19,153,526	$ 511,866	$ 38,920,617	$ 5,278,050	$ 562,988	$ -	$ -
Misc Revenue									
CWNB	$ (2,982,380)	$ (1,812,777)	$ (712,650)	$ (9,892)	$ (422,463)	$ (20,268)	$ (3,919)	$ (91)	$ (320)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,944)	$ (192,582)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	$ (7,982,380)	$ (4,553,479)	$ (1,813,803)	$ (744,836)	$ (615,045)	$ (217,677)	$ (37,130)	$ (91)	$ (320)
Operation									
CWMC	$ 9,059,160	$ 6,129,160	$ 871,060	$ 23,279	$ 1,770,023	$ 240,034	$ 25,603	$ -	$ -
CCA	$ 5,770,991	$ 4,560,985	$ 448,261	$ 1,778	$ 75,923	$ 3,643	$ 329	$ 595,765	$ 84,309
Sub-total	$ 14,830,151	$ 10,690,145	$ 1,319,321	$ 25,056	$ 1,845,947	$ 243,677	$ 25,932	$ 595,765	$ 84,309
Maintenance									
1860	$ 897,312	$ 607,095	$ 86,279	$ 2,306	$ 175,321	$ 23,775	$ 2,536	$ -	$ -
Billing and Collection									
CWMR	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -
CWNB	$ 30,647,811	$ 18,628,632	$ 7,323,403	$ 101,648	$ 4,341,349	$ 208,283	$ 40,276	$ 932	$ 3,288
Sub-total	$ 32,922,900	$ 20,306,462	$ 7,917,846	$ 104,464	$ 4,341,349	$ 208,283	$ 40,276	$ 932	$ 3,288
Total Operation, Maintenance and Billing	$ 48,650,363	$ 31,603,702	$ 9,323,446	$ 131,826	$ 6,362,617	$ 475,735	$ 68,744	$ 596,696	$ 87,597
Amortization Expense - Meters	$ 15,915,540	$ 10,767,985	$ 1,530,317	$ 40,897	$ 3,109,657	$ 421,703	$ 44,981	$ -	$ -
Allocated PILs	$ 3,815,362	$ 2,581,797	$ 366,281	$ 9,782	$ 745,224	$ 101,436	$ 10,842	$ -	$ -
Allocated Debt Return	$ 7,697,072	$ 5,208,492	$ 738,932	$ 19,734	$ 1,503,407	$ 204,636	$ 21,872	$ -	$ -
Allocated Equity Return	$ 8,359,132	$ 5,656,497	$ 802,490	$ 21,431	$ 1,632,722	$ 222,238	$ 23,753	$ -	$ -
Total	**$ 76,455,090**	**$ 51,264,994**	**$ 10,947,664**	**$ (521,166)**	**$ 12,738,583**	**$ 1,208,071**	**$ 133,061**	**$ 596,605**	**$ 87,277**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
Distribution Plant									
CWMC	$ 322,015,614	$ 217,866,269	$ 30,962,573	$ 827,455	$ 62,917,004	$ 8,532,216	$ 910,097	$ -	$ -
Accumulated Amortization									
Accum. Amortization of Electric Utility Plant - Meters only	$ (122,815,946)	$ (83,093,647)	$ (11,809,048)	$ (315,589)	$ (23,996,387)	$ (3,254,166)	$ (347,109)	$ -	$ -
Meter Net Fixed Assets	$ 199,199,669	$ 134,772,622	$ 19,153,526	$ 511,866	$ 38,920,617	$ 5,278,050	$ 562,988	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 24,482,574	$ 16,538,536	$ 2,387,817	$ 64,209	$ 4,797,591	$ 628,634	$ 65,786	$ -	$ -

Meter Net Fixed Assets Including General Plant	$ 223,682,243	$ 151,311,158	$ 21,541,343	$ 576,075	$ 43,718,208	$ 5,906,684	$ 628,775	$ -	$ -
Misc Revenue									
CWNB	$ (2,982,380)	$ (1,812,777)	$ (712,650)	$ (9,892)	$ (422,463)	$ (20,268)	$ (3,919)	$ (91)	$ (320)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,944)	$ (192,582)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	*$ (7,982,380)*	*$ (4,553,479)*	*$ (1,813,803)*	*$ (744,836)*	*$ (615,045)*	*$ (217,677)*	*$ (37,130)*	*$ (91)*	*$ (320)*
Operation									
CWMC	$ 9,059,160	$ 6,129,160	$ 871,060	$ 23,279	$ 1,770,023	$ 240,034	$ 25,603	$ -	$ -
CCA	$ 5,770,991	$ 4,560,985	$ 448,261	$ 1,778	$ 75,923	$ 3,643	$ 329	$ 595,765	$ 84,309
Sub-total	*$ 14,830,151*	*$ 10,690,145*	*$ 1,319,321*	*$ 25,056*	*$ 1,845,947*	*$ 243,677*	*$ 25,932*	*$ 595,765*	*$ 84,309*
Maintenance									
1860	$ 897,312	$ 607,095	$ 86,279	$ 2,306	$ 175,321	$ 23,775	$ 2,536	$ -	$ -
Billing and Collection									
CWMR	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -
CWNB	$ 30,647,811	$ 18,628,632	$ 7,323,403	$ 101,648	$ 4,341,349	$ 208,283	$ 40,276	$ 932	$ 3,288
Sub-total	*$ 32,922,900*	*$ 20,306,462*	*$ 7,917,846*	*$ 104,464*	*$ 4,341,349*	*$ 208,283*	*$ 40,276*	*$ 932*	*$ 3,288*
Total Operation, Maintenance and Billing	$ 48,650,363	$ 31,603,702	$ 9,323,446	$ 131,826	$ 6,362,617	$ 475,735	$ 68,744	$ 596,696	$ 87,597
Amortization Expense - Meters	$ 15,915,540	$ 10,767,985	$ 1,530,317	$ 40,897	$ 3,109,657	$ 421,703	$ 44,981	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 4,253,149	$ 2,873,099	$ 414,815	$ 11,155	$ 833,445	$ 109,207	$ 11,428	$ -	$ -
Admin and General	$ 15,448,843	$ 10,088,614	$ 2,847,476	$ 37,437	$ 2,050,552	$ 152,424	$ 21,920	$ 218,857	$ 31,562
Allocated PILs	$ 4,284,285	$ 2,898,621	$ 411,944	$ 11,009	$ 837,085	$ 113,518	$ 12,108	$ -	$ -
Allocated Debt Return	$ 8,643,073	$ 5,847,648	$ 831,052	$ 22,209	$ 1,688,726	$ 229,009	$ 24,427	$ -	$ -
Allocated Equity Return	$ 9,386,502	$ 6,350,630	$ 902,535	$ 24,120	$ 1,833,981	$ 248,707	$ 26,529	$ -	$ -
Total	**$ 98,599,375**	**$ 65,876,821**	**$ 14,447,783**	**$ (466,184)**	**$ 16,101,019**	**$ 1,532,626**	**$ 173,008**	**$ 815,462**	**$ 118,839**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
	Distribution Plant									
	CDMPP	$ 16,249,461	$ 8,165,702	$ 2,588,028	$ 174,738	$ 3,211,906	$ 1,200,877	$ 515,867	$ 336,085	$ 56,256
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 528,018,823	$ 417,308,883	$ 41,013,763	$ 162,648	$ 6,946,617	$ 333,276	$ 30,075	$ 54,509,684	$ 7,713,878
	SNCP	$ 246,674,917	$ 197,104,292	$ 19,371,715	$ 19,324	$ 786,082	$ 3,835	$ 93	$ 25,746,139	$ 3,643,437
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 210,249,884	$ 166,705,173	$ 16,384,042	$ 54,479	$ 2,216,153	$ 32,438	$ 736	$ 21,775,348	$ 3,081,514
	CWCS	$ 333,287,980	$ 240,339,125	$ 47,241,802	$ 235,627	$ 9,585,095	$ 46,766	$ 3,385	$ 31,393,556	$ 4,442,624
	CWMC	$ 322,015,614	$ 217,866,269	$ 30,962,573	$ 827,455	$ 62,917,004	$ 8,532,216	$ 910,097	$ -	$ -
	Sub-total	*$ 1,656,496,680*	*$ 1,247,489,445*	*$ 157,561,924*	*$ 1,474,272*	*$ 85,662,857*	*$ 10,149,408*	*$ 1,460,252*	*$ 133,760,813*	*$ 18,937,710*
	Accumulated Amortization									
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (888,133,858)	$ (673,815,060)	$ (84,008,013)	$ (656,316)	$ (36,904,856)	$ (4,274,042)	$ (733,797)	$ (76,859,044)	$ (10,882,729)
	Customer Related Net Fixed Assets	$ 768,362,821	$ 573,674,384	$ 73,553,911	$ 817,955	$ 48,758,001	$ 5,875,366	$ 726,455	$ 56,901,769	$ 8,054,981

Allocated General Plant Net Fixed Assets	$ 94,502,094	$ 70,398,085	$ 9,169,763	$ 102,606	$ 6,010,206	$ 699,776	$ 84,888	$ 7,038,027	$ 998,743
Customer Related NFA Including General Plant	$ 862,864,916	$ 644,072,470	$ 82,723,674	$ 920,561	$ 54,768,207	$ 6,575,142	$ 811,343	$ 63,939,796	$ 9,053,723
Misc Revenue									
CWNB	$ (10,681,756)	$ (6,492,682)	$ (2,552,443)	$ (35,428)	$ (1,513,101)	$ (72,594)	$ (14,037)	$ (325)	$ (1,146)
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (5,000,000)	$ (2,740,702)	$ (1,101,152)	$ (734,944)	$ (192,582)	$ (197,409)	$ (33,211)	$ -	$ -
Sub-total	*$ (15,681,756)*	*$ (9,233,384)*	*$ (3,653,596)*	*$ (770,372)*	*$ (1,705,683)*	*$ (270,003)*	*$ (47,248)*	*$ (325)*	*$ (1,146)*
Operating and Maintenance									
1815-1855	$ 16,271,355	$ 12,426,660	$ 1,532,616	$ 7,661	$ 356,474	$ 70,244	$ 33,675	$ 1,614,945	$ 229,081
1830 & 1835	$ 1,941,507	$ 1,542,387	$ 151,588	$ 388	$ 16,442	$ 663	$ 59	$ 201,470	$ 28,511
1850	$ 624,878	$ 495,460	$ 48,695	$ 162	$ 6,587	$ 96	$ 2	$ 64,718	$ 9,158
1840 & 1845	$ 1,314,854	$ 1,042,178	$ 102,427	$ 326	$ 13,856	$ 617	$ 55	$ 136,131	$ 19,264
CWMC	$ 9,059,160	$ 6,129,160	$ 871,060	$ 23,279	$ 1,770,023	$ 240,034	$ 25,603	$ -	$ -
CCA	$ 5,770,991	$ 4,560,985	$ 448,261	$ 1,778	$ 75,923	$ 3,643	$ 329	$ 595,765	$ 84,309
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 2,907,433	$ 2,309,744	$ 227,005	$ 582	$ 24,621	$ 994	$ 88	$ 301,703	$ 42,695
1855	$ 308,503	$ 222,467	$ 43,729	$ 218	$ 8,872	$ 43	$ 3	$ 29,059	$ 4,112
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 2,726,353	$ 2,160,957	$ 212,382	$ 675	$ 28,730	$ 1,280	$ 115	$ 282,268	$ 39,945
1860	$ 897,312	$ 607,095	$ 86,279	$ 2,306	$ 175,321	$ 23,775	$ 2,536	$ -	$ -
Sub-total	*$ 41,822,347*	*$ 31,497,092*	*$ 3,724,041*	*$ 37,374*	*$ 2,476,850*	*$ 341,390*	*$ 62,466*	*$ 3,226,058*	*$ 457,076*
Billing and Collection									
CWNB	$ 30,937,299	$ 18,804,591	$ 7,392,577	$ 102,609	$ 4,382,356	$ 210,251	$ 40,656	$ 940	$ 3,319
CWMR	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -
Sub-total	*$ 40,712,388*	*$ 24,696,700*	*$ 10,003,379*	*$ 964,285*	*$ 4,523,292*	*$ 479,817*	*$ 40,656*	*$ 940*	*$ 3,319*
Sub Total Operating, Maintenance and Biling	*$ 82,534,734*	*$ 56,193,792*	*$ 13,727,419*	*$ 1,001,659*	*$ 7,000,142*	*$ 821,207*	*$ 103,122*	*$ 3,226,999*	*$ 460,395*
Amortization Expense - Customer Related	$ 63,807,910	$ 46,869,091	$ 6,198,244	$ 80,736	$ 4,456,580	$ 738,531	$ 190,529	$ 4,618,262	$ 655,936
Amortization Expense - General Plant assigned to Meters	$ 16,417,043	$ 12,229,659	$ 1,592,985	$ 17,825	$ 1,044,102	$ 121,566	$ 14,747	$ 1,222,656	$ 173,503
Admin and General	$ 26,316,774	$ 17,938,325	$ 4,192,495	$ 284,457	$ 2,256,015	$ 263,111	$ 32,882	$ 1,183,601	$ 165,887
Allocated PILs	$ 16,525,556	$ 12,338,297	$ 1,581,960	$ 17,592	$ 1,048,662	$ 126,364	$ 15,624	$ 1,223,814	$ 173,242
Allocated Debt Return	$ 33,338,489	$ 24,891,154	$ 3,191,430	$ 35,490	$ 2,115,561	$ 254,926	$ 31,520	$ 2,468,910	$ 349,498
Allocated Equity Return	$ 36,206,080	$ 27,032,152	$ 3,465,939	$ 38,543	$ 2,297,529	$ 276,854	$ 34,231	$ 2,681,272	$ 379,559
PLCC Adjustment for Line Transformer	$ 4,932,376	$ 4,362,167	$ 429,097	$ 1,427	$ 58,017	$ 847	$ 19	$ -	$ 80,803
PLCC Adjustment for Primary Costs	$ 8,915,463	$ 7,857,965	$ 772,207	$ 3,029	$ 129,597	$ 6,166	$ 555	$ -	$ 145,944
PLCC Adjustment for Secondary Costs	$ 9,932,901	$ 8,755,311	$ 757,613	$ 2,879	$ 123,285	$ 5,853	$ -	$ -	$ 287,961
Total	**$ 235,684,090**	**$ 167,283,642**	**$ 28,337,959**	**$ 698,596**	**$ 18,202,010**	**$ 2,319,692**	**$ 374,833**	**$ 16,625,191**	**$ 1,842,168**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2.2 Primary Cost PLCC Adjustment Worksheet

Ontario

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$4,003,804	$933,112	$501,238	$268,278	$1,212,908	$734,288	$352,995	$0	$984
Depreciation on Acct 1835-4 Primary Overhead Conductors	$2,904,336	$676,874	$363,595	$194,607	$879,836	$532,648	$256,061	$0	$714
Depreciation on Acct 1840-4 Primary Underground Conduit	$16,550,117	$3,857,111	$2,071,915	$1,108,955	$5,013,674	$3,035,252	$1,459,141	$0	$4,070
Depreciation on Acct 1845-4 Primary Underground Conductors	$7,034,017	$1,639,323	$880,591	$471,320	$2,130,877	$1,290,022	$620,154	$0	$1,730
Depreciation on General Plant Assigned to Primary C&P	$8,045,460	$1,883,436	$1,024,398	$548,486	$2,461,445	$1,443,536	$682,177	$0	$1,981
Primary C&P Operations and Maintenance	$9,303,150	$2,315,645	$1,243,889	$614,135	$2,769,737	$1,595,745	$761,555	$0	$2,443
Allocation of General Expenses	$13,068,983	$3,045,810	$1,636,111	$875,698	$3,959,103	$2,396,820	$1,152,227	$0	$3,214
Admin and General Assigned to Primary C&P	$3,101,927	$779,137	$398,532	$201,520	$933,210	$534,588	$253,971	$0	$968
PILs on Primary C&P	$10,610,795	$2,472,914	$1,328,369	$710,985	$3,214,422	$1,945,995	$935,501	$0	$2,609
Debt Return on Primary C&P	$17,820,347	$4,153,146	$2,230,936	$1,194,067	$5,398,476	$3,268,209	$1,571,131	$0	$4,382
Equity Return on Primary C&P	$17,019,998	$3,966,620	$2,130,740	$1,140,439	$5,156,019	$3,121,427	$1,500,568	$0	$4,185
Total	**$109,462,934**	**$25,723,128**	**$13,810,313**	**$7,328,493**	**$33,129,706**	**$19,898,531**	**$9,545,482**	**$0**	**$27,280**
Primary NCP	16,967,957	3,954,491	2,124,225	1,136,952	5,140,253	3,111,883	1,495,980	0	4,172
PLCC Amount	1,251,061	987,451	107,094	3,416	15,122	845	78	108,701	28,354
Adjustment to Customer Related Cost for PLCC	**$7,430,190**	**$6,423,161**	**$696,257**	**$22,019**	**$97,461**	**$5,402**	**$500**	**$0**	**$185,390**
General Plant - Gross Assets	$515,626,311	$252,800,034	$71,760,343	$20,401,261	$93,723,481	$37,553,874	$15,727,829	$19,627,858	$4,031,629
General Plant - Accumulated Depreciation	($327,142,327)	($160,390,557)	($45,528,797)	($12,943,707)	($59,463,447)	($23,826,290)	($9,978,619)	($12,453,017)	($2,557,892)
General Plant - Net Fixed Assets	$188,483,984	$92,409,477	$26,231,546	$7,457,554	$34,260,035	$13,727,585	$5,749,210	$7,174,841	$1,473,737
General Plant - Depreciation	$30,913,004	$15,155,954	$4,302,201	$1,223,103	$5,618,942	$2,251,443	$942,920	$1,176,736	$241,706
Total Net Fixed Assets Excluding General Plant	**$1,503,330,620**	**$736,868,257**	**$206,580,333**	**$58,709,267**	**$271,716,303**	**$112,388,836**	**$47,881,760**	**$57,399,991**	**$11,785,874**
Total Administration and General Expense	**$48,663,412**	**$23,569,439**	**$7,713,646**	**$2,030,534**	**$8,677,110**	**$3,600,274**	**$1,543,228**	**$1,263,820**	**$265,360**
Total O&M	**$145,255,728**	**$70,049,830**	**$24,075,643**	**$6,188,069**	**$25,753,386**	**$10,746,822**	**$4,627,509**	**$3,145,050**	**$669,419**
Primary Conductors and Poles Gross Assets									
Acct 1830-4 Primary Poles, Towers & Fixtures	$109,511,821	$25,522,432	$13,709,824	$7,337,932	$33,175,386	$20,084,208	$9,655,111	$0	$26,928
Acct 1835-4 Primary Overhead Conductors	$80,763,103	$18,822,359	$10,110,761	$5,411,600	$24,466,282	$14,811,761	$7,120,480	$0	$19,859
Acct 1840-4 Primary Underground Conduit	$465,954,258	$108,593,628	$58,332,978	$31,221,660	$141,155,650	$85,454,905	$41,080,862	$0	$114,574
Acct 1845-4 Primary Underground Conductors	$205,428,797	$47,876,499	$25,717,704	$13,764,930	$62,232,365	$37,675,154	$18,111,632	$0	$50,513
Subtotal	*$861,657,978*	*$200,814,918*	*$107,871,267*	*$57,736,123*	*$261,029,683*	*$158,026,029*	*$75,968,085*	*$0*	*$211,874*
Primary Conductors and Poles Accumulated Depreciation									
Acct 1830-4 Primary Poles, Towers & Fixtures	($50,841,898)	($11,849,030)	($6,364,915)	($3,406,704)	($15,401,986)	($9,324,283)	($4,482,476)	$0	($12,502)

Acct 1835-4 Primary Overhead Conductors	($55,134,170)	($12,849,372)	($6,902,266)	($3,694,312)	($16,702,283)	($10,111,476)	($4,860,905)	$0	($13,557)
Acct 1840-4 Primary Underground Conduit	($243,995,216)	($56,864,650)	($30,545,847)	($16,349,106)	($73,915,632)	($44,748,144)	($21,511,841)	$0	($59,996)
Acct 1845-4 Primary Underground Conductors	($118,773,779)	($27,680,991)	($14,869,331)	($7,958,538)	($35,981,193)	($21,782,829)	($10,471,691)	$0	($29,205)
Subtotal	***($468,745,063)***	***($109,244,043)***	***($58,682,360)***	***($31,408,660)***	***($142,001,094)***	***($85,966,732)***	***($41,326,913)***	***$0***	***($115,260)***
Primary Conductor & Pools - Net Fixed Assets	$392,912,915	$91,570,875	$49,188,907	$26,327,463	$119,028,590	$72,059,296	$34,641,171	$0	$96,614
General Plant Assigned to Primary C&P - NFA	$49,055,096	$11,483,758	$6,246,002	$3,344,250	$15,008,020	$8,801,587	$4,159,399	$0	$12,081
Primary C&P Net Fixed Assets Including General Plant	$441,968,011	$103,054,633	$55,434,908	$29,671,713	$134,036,609	$80,860,883	$38,800,571	$0	$108,695
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$97,192,258	$50,158,956	$26,943,766	$3,612,494	$15,462,368	$961,752	$0	$0	$52,921
Acct 1835-5 Secondary Overhead Conductors	$71,677,635	$36,991,376	$19,870,568	$2,664,153	$11,403,233	$709,276	$0	$0	$39,029
Acct 1840-5 Secondary Underground Conduit	$165,933,805	$85,635,077	$46,000,388	$6,167,517	$26,398,497	$1,641,975	$0	$0	$90,351
Acct 1845-5 Secondary Underground Conductors	$73,156,498	$37,754,588	$20,280,541	$2,719,120	$11,638,506	$723,910	$0	$0	$39,834
Subtotal	***$407,960,197***	***$210,539,997***	***$113,095,264***	***$15,163,285***	***$64,902,603***	***$4,036,913***	***$0***	***$0***	***$222,135***
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$337,614	$123,612	$66,400	$17,886	$79,441	$34,375	$15,770	$0	$130
Acct 5025 Overhead Distribution Lines & Feeders - Other	$283,804	$103,910	$55,817	$15,035	$66,779	$28,896	$13,256	$0	$110
Acct 5040 Underground Distribution Lines & Feeders - Labour	$834,543	$256,521	$137,795	$49,380	$221,291	$115,030	$54,256	$0	$271
Acct 5045 Underground Distribution Lines & Feeders - Other	$933,868	$287,051	$154,194	$55,258	$247,628	$128,721	$60,713	$0	$303
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$4,523,679	$1,656,273	$889,696	$239,648	$1,064,428	$460,587	$211,300	$0	$1,747
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$2,720,669	$996,129	$535,088	$144,131	$640,177	$277,010	$127,082	$0	$1,051
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$4,294,175	$1,319,936	$709,027	$254,089	$1,138,662	$591,892	$279,177	$0	$1,393
Total	**$13,928,352**	**$4,743,432**	**$2,548,018**	**$775,426**	**$3,458,407**	**$1,636,510**	**$761,555**	**$0**	**$5,005**
General Expenses									
Acct 5005 - Operation Supervision and Engineering	$17,006,071	$5,408,275	$2,902,206	$1,076,382	$4,764,331	$2,000,733	$847,787	$466	$5,891
Acct 5010 - Load Dispatching	$4,817,060	$1,531,923	$822,065	$304,891	$1,349,522	$566,718	$240,140	$132	$1,669
Acct 5085 - Miscellaneous Distribution Expense	$4,281,374	$1,361,564	$730,647	$270,985	$1,199,447	$503,696	$213,435	$117	$1,483
Acct 5105 - Maintenance Supervision and Engineering	$2,098,226	$667,278	$358,077	$132,805	$587,828	$246,852	$104,601	$57	$727
Total	**$28,202,730**	**$8,969,039**	**$4,812,995**	**$1,785,063**	**$7,901,128**	**$3,317,999**	**$1,405,964**	**$772**	**$9,769**
Primary Conductors and Poles Gross Assets	$861,657,978	$200,814,918	$107,871,267	$57,736,123	$261,029,683	$158,026,029	$75,968,085	$0	$211,874
Acct 1815 - 1855	$1,859,448,991	$591,342,436	$317,328,089	$117,691,955	$520,933,423	$218,760,752	$92,697,331	$50,917	$644,087

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2.2 Primary Cost PLCC Adjustment Worksheet

Ontario

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	3	4	5	6	7	9
Description	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$4,124,087	$1,006,686	$487,332	$161,295	$1,339,286	$761,151	$365,277	$0	$3,060
Depreciation on Acct 1835-4 Primary Overhead Conductors	$2,947,352	$719,446	$348,280	$115,273	$957,144	$543,970	$261,052	$0	$2,187
Depreciation on Acct 1840-4 Primary Underground Conduit	$17,273,338	$4,216,405	$2,041,141	$675,569	$5,609,468	$3,188,009	$1,529,929	$0	$12,816
Depreciation on Acct 1845-4 Primary Underground Conductors	$7,820,289	$1,908,925	$924,101	$305,856	$2,539,617	$1,443,332	$692,656	$0	$5,803
Depreciation on General Plant Assigned to Primary C&P	$8,452,244	$2,072,727	$1,016,728	$338,458	$2,773,691	$1,525,584	$718,711	$0	$6,346
Primary C&P Operations and Maintenance	$10,251,431	$2,664,952	$1,290,090	$395,093	$3,273,481	$1,774,162	$845,552	$0	$8,101
Allocation of General Expenses	$13,906,778	$3,394,631	$1,643,324	$543,902	$4,516,187	$2,566,668	$1,231,747	$0	$10,319
Admin and General Assigned to Primary C&P	$3,324,065	$871,836	$400,268	$123,922	$1,073,965	$577,573	$273,477	$0	$3,024
PILs on Primary C&P	$9,883,971	$2,412,668	$1,167,961	$386,567	$3,209,792	$1,824,210	$875,440	$0	$7,334
Debt Return on Primary C&P	$17,898,358	$4,368,972	$2,114,998	$700,014	$5,812,442	$3,303,364	$1,585,288	$0	$13,280
Equity Return on Primary C&P	$19,397,066	$4,734,805	$2,292,096	$758,630	$6,299,143	$3,579,969	$1,718,031	$0	$14,392
Total	**$115,278,979**	**$28,372,053**	**$13,726,318**	**$4,504,579**	**$37,404,217**	**$21,087,992**	**$10,097,158**	**$0**	**$86,662**
Primary NCP	16,926,396	4,131,717	2,000,144	662,000	5,496,800	3,123,977	1,499,199	0	12,559
PLCC Amount	1,287,219	1,031,307	107,005	1,704	16,864	858	78	109,294	20,109
Adjustment to Customer Related Cost for PLCC	**$8,087,638**	**$7,081,875**	**$734,338**	**$11,595**	**$114,755**	**$5,789**	**$528**	**$0**	**$138,758**
General Plant - Gross Assets	$558,181,412	$281,622,790	$73,555,792	$12,544,073	$110,039,124	$40,753,068	$16,957,007	$19,603,947	$3,105,611
General Plant - Accumulated Depreciation	($357,714,605)	($180,480,007)	($47,138,763)	($8,038,960)	($70,519,370)	($26,116,899)	($10,867,021)	($12,563,331)	($1,990,253)
General Plant - Net Fixed Assets	$200,466,807	$101,142,783	$26,417,029	$4,505,113	$39,519,753	$14,636,169	$6,089,986	$7,040,615	$1,115,358
General Plant - Depreciation	$33,705,954	$17,005,878	$4,441,689	$757,478	$6,644,746	$2,460,886	$1,023,954	$1,183,790	$187,533
Total Net Fixed Assets Excluding General Plant	**$1,647,880,007**	**$831,489,676**	**$214,325,525**	**$36,340,676**	**$322,997,729**	**$123,604,017**	**$52,390,799**	**$57,628,446**	**$9,103,139**
Total Administration and General Expense	**$50,136,382**	**$24,911,367**	**$7,602,828**	**$1,245,816**	**$9,624,133**	**$3,714,100**	**$1,592,202**	**$1,242,271**	**$203,664**
Total O&M	**$154,095,114**	**$76,146,904**	**$24,504,409**	**$3,971,964**	**$29,334,670**	**$11,408,810**	**$4,922,856**	**$3,259,987**	**$545,515**
Primary Conductors and Poles Gross Assets									
Acct 1830-4 Primary Poles, Towers & Fixtures	$113,816,109	$27,782,403	$13,449,324	$4,451,409	$36,961,464	$21,006,176	$10,080,884	$0	$84,449
Acct 1835-4 Primary Overhead Conductors	$83,635,541	$20,415,355	$9,882,972	$3,271,031	$27,160,408	$15,435,978	$7,407,740	$0	$62,056
Acct 1840-4 Primary Underground Conduit	$492,384,479	$120,190,579	$58,183,665	$19,257,420	$159,900,486	$90,875,670	$43,611,320	$0	$365,340
Acct 1845-4 Primary Underground Conductors	$228,917,347	$55,878,505	$27,050,508	$8,953,080	$74,340,270	$42,249,539	$20,275,594	$0	$169,852
Subtotal	*$918,753,475*	*$224,266,841*	*$108,566,469*	*$35,932,940*	*$298,362,628*	*$169,567,362*	*$81,375,538*	*$0*	*$681,697*
Primary Conductors and Poles Accumulated Depreciation									
Acct 1830-4 Primary Poles, Towers & Fixtures	($55,033,630)	($13,433,656)	($6,503,167)	($2,152,395)	($17,872,018)	($10,157,140)	($4,874,421)	$0	($40,834)

Acct 1835-4 Primary Overhead Conductors	($58,196,320)	($14,205,666)	($6,876,893)	($2,276,089)	($18,899,093)	($10,740,854)	($5,154,546)	$0	($43,181)
Acct 1840-4 Primary Underground Conduit	($262,278,288)	($64,021,878)	($30,992,675)	($10,257,844)	($85,174,142)	($48,406,715)	($23,230,428)	$0	($194,605)
Acct 1845-4 Primary Underground Conductors	($128,067,759)	($31,261,217)	($15,133,401)	($5,008,799)	($41,589,647)	($23,636,495)	($11,343,176)	$0	($95,024)
Subtotal	***($503,575,997)***	***($122,922,417)***	***($59,506,135)***	***($19,695,127)***	***($163,534,900)***	***($92,941,203)***	***($44,602,571)***	***$0***	***($373,644)***
Primary Conductor & Pools - Net Fixed Assets	$415,177,478	$101,344,424	$49,060,335	$16,237,813	$134,827,728	$76,626,159	$36,772,966	$0	$308,054
General Plant Assigned to Primary C&P - NFA	$50,269,884	$12,327,582	$6,047,009	$2,012,983	$16,496,582	$9,073,438	$4,274,546	$0	$37,744
Primary C&P Net Fixed Assets Including General Plant	$465,447,362	$113,672,006	$55,107,343	$18,250,797	$151,324,310	$85,699,597	$41,047,512	$0	$345,798
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$101,012,334	$54,218,325	$26,246,823	$2,178,988	$17,204,549	$998,843	$0	$0	$164,806
Acct 1835-5 Secondary Overhead Conductors	$74,226,937	$39,841,276	$19,286,965	$1,601,187	$12,642,426	$733,980	$0	$0	$121,104
Acct 1840-5 Secondary Underground Conduit	$175,346,032	$94,116,905	$45,561,529	$3,782,477	$29,865,159	$1,733,878	$0	$0	$286,084
Acct 1845-5 Secondary Underground Conductors	$81,521,149	$43,756,441	$21,182,277	$1,758,534	$13,884,786	$806,107	$0	$0	$133,005
Subtotal	***$432,106,452***	***$231,932,947***	***$112,277,593***	***$9,321,185***	***$73,596,919***	***$4,272,808***	***$0***	***$0***	***$704,999***
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$331,641	$126,588	$61,281	$10,236	$83,619	$33,970	$15,562	$0	$385
Acct 5025 Overhead Distribution Lines & Feeders - Other	$289,948	$110,674	$53,577	$8,949	$73,106	$29,700	$13,606	$0	$336
Acct 5040 Underground Distribution Lines & Feeders - Labour	$879,729	$282,348	$136,683	$30,355	$250,015	$122,012	$57,458	$0	$858
Acct 5045 Underground Distribution Lines & Feeders - Other	$1,385,783	$444,766	$215,309	$47,816	$393,832	$192,198	$90,509	$0	$1,352
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$4,942,817	$1,886,690	$913,337	$152,554	$1,246,263	$506,296	$231,943	$0	$5,735
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$2,813,097	$1,073,768	$519,806	$86,823	$709,283	$288,147	$132,005	$0	$3,264
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$4,661,694	$1,496,166	$724,287	$160,851	$1,324,830	$646,544	$304,468	$0	$4,548
Total	**$15,304,709**	**$5,421,001**	**$2,624,280**	**$497,582**	**$4,080,948**	**$1,818,868**	**$845,552**	**$0**	**$16,478**
General Expenses									
Acct 5005 - Operation Supervision and Engineering	$19,053,831	$6,321,092	$3,055,094	$703,013	$5,736,550	$2,260,920	$956,968	$781	$19,412
Acct 5010 - Load Dispatching	$4,980,928	$1,652,419	$798,643	$183,777	$1,499,612	$591,035	$250,164	$204	$5,075
Acct 5085 - Miscellaneous Distribution Expense	$3,984,372	$1,321,812	$638,855	$147,008	$1,199,578	$472,784	$200,113	$163	$4,059
Acct 5105 - Maintenance Supervision and Engineering	$2,093,221	$694,424	$335,627	$77,232	$630,208	$248,381	$105,131	$86	$2,133
Total	**$30,112,352**	**$9,989,748**	**$4,828,219**	**$1,111,031**	**$9,065,946**	**$3,573,120**	**$1,512,376**	**$1,234**	**$30,678**
Primary Conductors and Poles Gross Assets	$918,753,475	$224,266,841	$108,566,469	$35,932,940	$298,362,628	$169,567,362	$81,375,538	$0	$681,697
Acct 1815 - 1855	$1,989,377,367	$659,974,284	$318,977,086	$73,400,415	$598,943,202	$236,058,743	$99,915,387	$81,494	$2,026,757

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2.2 Primary Cost PLCC Adjustment Worksheet

Ontario

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	3	4	5	6	7	9
Description	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$4,257,847	$1,055,065	$542,845	$48,361	$1,441,033	$788,579	$378,846	$0	$3,119
Depreciation on Acct 1835-4 Primary Overhead Conductors	$2,960,760	$733,656	$377,476	$33,629	$1,002,044	$548,351	$263,437	$0	$2,169
Depreciation on Acct 1840-4 Primary Underground Conduit	$18,371,394	$4,552,304	$2,342,221	$208,664	$6,217,644	$3,402,492	$1,634,613	$0	$13,456
Depreciation on Acct 1845-4 Primary Underground Conductors	$8,739,649	$2,165,624	$1,114,243	$99,266	$2,957,861	$1,618,635	$777,619	$0	$6,401
Depreciation on General Plant Assigned to Primary C&P	$9,331,872	$2,326,073	$1,215,842	$108,990	$3,191,289	$1,687,401	$795,329	$0	$6,947
Primary C&P Operations and Maintenance	$11,082,197	$2,923,470	$1,504,164	$123,875	$3,683,357	$1,921,774	$916,916	$0	$8,641
Allocation of General Expenses	$13,882,470	$3,439,980	$1,769,915	$157,679	$4,698,405	$2,571,117	$1,235,207	$0	$10,168
Admin and General Assigned to Primary C&P	$3,526,099	$933,237	$459,387	$35,179	$1,187,077	$615,729	$292,376	$0	$3,114
PILs on Primary C&P	$9,470,549	$2,346,736	$1,207,427	$107,568	$3,205,228	$1,754,002	$842,651	$0	$6,936
Debt Return on Primary C&P	$19,105,788	$4,734,281	$2,435,851	$217,006	$6,466,193	$3,538,507	$1,699,957	$0	$13,993
Equity Return on Primary C&P	$20,749,162	$5,141,498	$2,645,369	$235,671	$7,022,379	$3,842,869	$1,846,177	$0	$15,197
Total	**$121,477,787**	**$30,351,925**	**$15,614,740**	**$1,375,888**	**$41,072,510**	**$22,289,457**	**$10,683,128**	**$0**	**$90,140**
Primary NCP	16,957,468	4,201,943	2,161,955	192,605	5,739,112	3,140,625	1,508,808	0	12,420
PLCC Amount	0	0	0	0	0	0	0	0	0
Adjustment to Customer Related Cost for PLCC	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$608,985,853	$308,914,029	$82,648,824	$3,899,540	$126,253,744	$45,240,440	$18,866,818	$19,977,723	$3,184,735
General Plant - Accumulated Depreciation	($392,984,547)	($199,345,255)	($53,334,097)	($2,516,412)	($81,472,780)	($29,194,100)	($12,174,943)	($12,891,821)	($2,055,141)
General Plant - Net Fixed Assets	$216,001,306	$109,568,775	$29,314,727	$1,383,129	$44,780,964	$16,046,340	$6,691,875	$7,085,902	$1,129,594
General Plant - Depreciation	$37,524,065	$19,034,449	$5,092,598	$240,279	$7,779,415	$2,787,594	$1,162,522	$1,230,973	$196,235
Total Net Fixed Assets Excluding General Plant	**$1,760,726,733**	**$892,876,546**	**$235,143,779**	**$11,026,054**	**$363,287,092**	**$134,726,046**	**$57,268,065**	**$57,288,835**	**$9,110,316**
Total Administration and General Expense	**$51,064,651**	**$25,723,351**	**$7,799,973**	**$489,694**	**$10,215,002**	**$3,796,873**	**$1,623,272**	**$1,216,456**	**$200,029**
Total O&M	**$160,353,857**	**$80,581,251**	**$25,539,329**	**$1,724,361**	**$31,695,918**	**$11,850,560**	**$5,090,713**	**$3,316,574**	**$555,151**
Primary Conductors and Poles Gross Assets									
Acct 1830-4 Primary Poles, Towers & Fixtures	$118,355,926	$29,327,776	$15,089,532	$1,344,300	$40,056,568	$21,920,228	$10,530,836	$0	$86,686
Acct 1835-4 Primary Overhead Conductors	$86,580,438	$21,454,031	$11,038,385	$983,391	$29,302,421	$16,035,217	$7,703,581	$0	$63,413
Acct 1840-4 Primary Underground Conduit	$521,649,007	$129,260,997	$66,506,506	$5,924,950	$176,547,718	$96,612,529	$46,414,239	$0	$382,067
Acct 1845-4 Primary Underground Conductors	$254,021,014	$62,944,641	$32,385,857	$2,885,200	$85,971,275	$47,046,217	$22,601,772	$0	$186,050
Subtotal	*$980,606,385*	*$242,987,445*	*$125,020,280*	*$11,137,840*	*$331,877,982*	*$181,614,191*	*$87,250,429*	*$0*	*$718,217*
Primary Conductors and Poles Accumulated Depreciation									
Acct 1830-4 Primary Poles, Towers & Fixtures	($59,352,176)	($14,707,057)	($7,566,977)	($674,129)	($20,087,245)	($10,992,379)	($5,280,919)	$0	($43,471)

Acct 1835-4 Primary Overhead Conductors	($61,286,460)	($15,186,359)	($7,813,584)	($696,099)	($20,741,887)	($11,350,621)	($5,453,024)	$0	($44,888)
Acct 1840-4 Primary Underground Conduit	($281,491,228)	($69,751,569)	($35,888,112)	($3,197,210)	($95,268,338)	($52,133,866)	($25,045,962)	$0	($206,170)
Acct 1845-4 Primary Underground Conductors	($138,139,304)	($34,229,959)	($17,611,770)	($1,569,002)	($46,752,085)	($25,584,229)	($12,291,082)	$0	($101,176)
Subtotal	***($540,269,168)***	***($133,874,944)***	***($68,880,443)***	***($6,136,440)***	***($182,849,555)***	***($100,061,094)***	***($48,070,987)***	***$0***	***($395,705)***
Primary Conductor & Pools - Net Fixed Assets	$440,337,217	$109,112,501	$56,139,837	$5,001,401	$149,028,427	$81,553,097	$39,179,442	$0	$322,513
General Plant Assigned to Primary C&P - NFA	$53,717,433	$13,389,671	$6,998,799	$627,385	$18,370,145	$9,713,257	$4,578,187	$0	$39,989
Primary C&P Net Fixed Assets Including General Plant	$494,054,650	$122,502,172	$63,138,635	$5,628,786	$167,398,572	$91,266,354	$43,757,629	$0	$362,501
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$105,041,443	$56,038,896	$28,832,759	$646,124	$18,337,512	$1,020,515	$0	$0	$165,639
Acct 1835-5 Secondary Overhead Conductors	$76,840,547	$40,993,909	$21,091,913	$472,656	$13,414,367	$746,533	$0	$0	$121,169
Acct 1840-5 Secondary Underground Conduit	$185,767,601	$99,105,752	$50,991,231	$1,142,681	$32,430,205	$1,804,798	$0	$0	$292,935
Acct 1845-5 Secondary Underground Conductors	$90,460,969	$48,260,312	$24,830,574	$556,437	$15,792,139	$878,861	$0	$0	$142,647
Subtotal	***$458,110,560***	***$244,398,868***	***$125,746,476***	***$2,817,897***	***$79,974,222***	***$4,450,707***	***$0***	***$0***	***$722,389***
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$398,333	$152,215	$78,317	$3,549	$104,121	$40,905	$18,777	$0	$450
Acct 5025 Overhead Distribution Lines & Feeders - Other	$304,859	$116,496	$59,939	$2,716	$79,687	$31,306	$14,371	$0	$344
Acct 5040 Underground Distribution Lines & Feeders - Labour	$949,945	$306,659	$157,780	$9,491	$280,623	$132,158	$62,327	$0	$906
Acct 5045 Underground Distribution Lines & Feeders - Other	$1,491,927	$481,621	$247,800	$14,905	$440,730	$207,560	$97,887	$0	$1,424
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$5,399,518	$2,063,314	$1,061,602	$48,109	$1,411,386	$554,478	$254,530	$0	$6,099
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$2,902,464	$1,109,116	$570,655	$25,860	$758,678	$298,055	$136,821	$0	$3,278
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$5,063,227	$1,634,500	$840,972	$50,585	$1,495,728	$704,407	$332,203	$0	$4,831
Total	**$16,510,274**	**$5,863,921**	**$3,017,066**	**$155,216**	**$4,570,954**	**$1,968,870**	**$916,916**	**$0**	**$17,332**
General Expenses									
Acct 5005 - Operation Supervision and Engineering	$18,984,710	$6,328,810	$3,245,833	$202,171	$5,953,830	$2,270,151	$963,618	$1,269	$19,028
Acct 5010 - Load Dispatching	$5,190,650	$1,730,373	$887,450	$55,276	$1,627,849	$620,687	$263,465	$347	$5,202
Acct 5085 - Miscellaneous Distribution Expense	$3,923,793	$1,308,049	$670,854	$41,785	$1,230,548	$469,199	$199,162	$262	$3,933
Acct 5105 - Maintenance Supervision and Engineering	$2,119,078	$706,423	$362,301	$22,566	$664,568	$253,395	$107,559	$142	$2,124
Total	**$30,218,231**	**$10,073,656**	**$5,166,438**	**$321,799**	**$9,476,796**	**$3,613,432**	**$1,533,804**	**$2,020**	**$30,287**
Primary Conductors and Poles Gross Assets	$980,606,385	$242,987,445	$125,020,280	$11,137,840	$331,877,982	$181,614,191	$87,250,429	$0	$718,217
Acct 1815 - 1855	$2,134,504,121	$711,565,819	$364,938,055	$22,730,662	$669,405,807	$255,239,489	$108,342,251	$142,691	$2,139,347

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet

Ontario

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$3,672,758	$1,895,436	$1,018,167	$136,511	$584,301	$36,343	$0	$0	$2,000
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,142,994	$2,517,696	$868,871	$101,070	$432,519	$26,671	$1	$162,313	$33,853
Depreciation on Acct 1840-5 Secondary Underground Conduit	$7,978,128	$4,848,305	$1,673,178	$194,630	$832,897	$51,360	$1	$312,565	$65,191
Depreciation on Acct 1845-5 Secondary Underground Conductors	$3,885,749	$2,361,368	$814,922	$94,795	$405,663	$25,015	$1	$152,235	$31,751
Depreciation on General Plant Assigned to Secondary C&P	$3,525,640	$1,811,260	$985,142	$132,130	$561,376	$33,825	$0	$0	$1,905
Secondary C&P Operations and Maintenance	$4,625,202	$2,427,787	$1,304,128	$161,291	$688,669	$40,765	$0	$0	$2,561
Allocation of General Expenses	$6,187,635	$3,193,313	$1,715,344	$229,985	$984,394	$61,229	$0	$0	$3,369
Admin and General Assigned to Primary C&P	$1,534,333	$816,870	$417,832	$52,925	$232,034	$13,657	$0	$0	$1,015
PILs on Secondary C&P	$4,608,104	$2,378,149	$1,277,465	$171,277	$733,106	$45,599	$0	$0	$2,509
Debt Return on Secondary C&P	$7,739,101	$3,993,993	$2,145,444	$287,651	$1,231,218	$76,581	$0	$0	$4,214
Equity Return on Secondary C&P	$7,391,522	$3,814,615	$2,049,087	$274,732	$1,175,921	$73,142	$0	$0	$4,025
Total	**$55,291,166**	**$30,058,793**	**$14,269,581**	**$1,836,998**	**$7,862,098**	**$484,187**	**$2**	**$627,112**	**$152,395**
Secondary NCP	7,662,558	3,954,491	2,124,225	284,806	1,219,040	75,824	0	0	4,172
PLCC Amount	1,250,983	987,451	107,094	3,416	15,122	845	0	108,701	28,354
Adjustment to Customer Related Cost for PLCC	**$9,385,791**	**$7,505,793**	**$719,412**	**$22,033**	**$97,525**	**$5,395**	**$0**	**$0**	**$1,035,634**
General Plant - Gross Assets	$515,626,311	$252,800,034	$71,760,343	$20,401,261	$93,723,481	$37,553,874	$15,727,829	$19,627,858	$4,031,629
General Plant - Accumulated Depreciation	($327,142,327)	($160,390,557)	($45,528,797)	($12,943,707)	($59,463,447)	($23,826,290)	($9,978,619)	($12,453,017)	($2,557,892)
General Plant - Net Fixed Assets	$188,483,984	$92,409,477	$26,231,546	$7,457,554	$34,260,035	$13,727,585	$5,749,210	$7,174,841	$1,473,737
General Plant - Depreciation	$30,913,004	$15,155,954	$4,302,201	$1,223,103	$5,618,942	$2,251,443	$942,920	$1,176,736	$241,706
Total Net Fixed Assets Excluding General Plant	$1,503,330,620	$736,868,257	$206,580,333	$58,709,267	$271,716,303	$112,388,836	$47,881,760	$57,399,991	$11,785,874
Total Administration and General Expense	$48,663,412	$23,569,439	$7,713,646	$2,030,534	$8,677,110	$3,600,274	$1,543,228	$1,263,820	$265,360
Total O&M	$145,255,728	$70,049,830	$24,075,643	$6,188,069	$25,753,386	$10,746,822	$4,627,509	$3,145,050	$669,419
Secondary Conductors and Poles Gross Plant									
Acct 1830-5 Secondary Poles, Towers & Fixtures	$97,192,258	$50,158,956	$26,943,766	$3,612,494	$15,462,368	$961,752	$0	$0	$52,921
Acct 1835-5 Secondary Overhead Conductors	$71,677,635	$36,991,376	$19,870,568	$2,664,153	$11,403,233	$709,276	$0	$0	$39,029
Acct 1840-5 Secondary Underground Conduit	$165,933,805	$85,635,077	$46,000,388	$6,167,517	$26,398,497	$1,641,975	$0	$0	$90,351
Acct 1845-5 Secondary Underground Conductors	$73,156,498	$37,754,588	$20,280,541	$2,719,120	$11,638,506	$723,910	$0	$0	$39,834
Subtotal	***$407,960,197***	***$210,539,997***	***$113,095,264***	***$15,163,285***	***$64,902,603***	***$4,036,913***	***$0***	***$0***	***$222,135***
Secondary Conductors and Poles Accumulated Depreciation									
Acct 1830-5 Secondary Poles, Towers & Fixtures	($42,748,559)	($22,061,666)	($11,850,812)	($1,588,902)	($6,800,891)	($423,012)	$0	$0	($23,277)

Acct 1835-5 Secondary Overhead Conductors	($46,634,402)	($24,067,070)	($12,928,050)	($1,733,333)	($7,419,092)	($461,464)	$0	$0	($25,392)
Acct 1840-5 Secondary Underground Conduit	($106,077,470)	($54,744,434)	($29,406,936)	($3,942,745)	($16,875,921)	($1,049,675)	$0	$0	($57,759)
Acct 1845-5 Secondary Underground Conductors	($41,863,764)	($21,605,041)	($11,605,528)	($1,556,015)	($6,660,128)	($414,257)	$0	$0	($22,795)
Subtotal	***($237,324,194)***	***($122,478,211)***	***($65,791,326)***	***($8,820,994)***	***($37,756,031)***	***($2,348,408)***	***$0***	***$0***	***($129,223)***
Secondary Conductor & Pools - Net Fixed Assets	$170,636,003	$88,061,786	$47,303,938	$6,342,291	$27,146,572	$1,688,505	$0	$0	$92,911
General Plant Assigned to Secondary C&P - NFA	$21,496,670	$11,043,689	$6,006,648	$805,631	$3,422,844	$206,240	$0	$0	$11,618
Secondary C&P Net Fixed Assets Including General Plant	$192,132,672	$99,105,475	$53,310,586	$7,147,922	$30,569,416	$1,894,745	$0	$0	$104,529
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$109,511,821	$25,522,432	$13,709,824	$7,337,932	$33,175,386	$20,084,208	$9,655,111	$0	$26,928
Acct 1835-4 Primary Overhead Conductors	$80,763,103	$18,822,359	$10,110,761	$5,411,600	$24,466,282	$14,811,761	$7,120,480	$0	$19,859
Acct 1840-4 Primary Underground Conduit	$465,954,258	$108,593,628	$58,332,978	$31,221,660	$141,155,650	$85,454,905	$41,080,862	$0	$114,574
Acct 1845-4 Primary Underground Conductors	$205,428,797	$47,876,499	$25,717,704	$13,764,930	$62,232,365	$37,675,154	$18,111,632	$0	$50,513
Subtotal	***$861,657,978***	***$200,814,918***	***$107,871,267***	***$57,736,123***	***$261,029,683***	***$158,026,029***	***$75,968,085***	***$0***	***$211,874***
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$337,614	$123,612	$66,400	$17,886	$79,441	$34,375	$15,770	$0	$130
Acct 5025 Overhead Distribution Lines & Feeders - Other	$283,804	$103,910	$55,817	$15,035	$66,779	$28,896	$13,256	$0	$110
Acct 5040 Underground Distribution Lines & Feeders - Labour	$834,543	$256,521	$137,795	$49,380	$221,291	$115,030	$54,256	$0	$271
Acct 5045 Underground Distribution Lines & Feeders - Other	$933,868	$287,051	$154,194	$55,258	$247,628	$128,721	$60,713	$0	$303
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$4,523,679	$1,656,273	$889,696	$239,648	$1,064,428	$460,587	$211,300	$0	$1,747
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$2,720,669	$996,129	$535,088	$144,131	$640,177	$277,010	$127,082	$0	$1,051
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$4,294,175	$1,319,936	$709,027	$254,089	$1,138,662	$591,892	$279,177	$0	$1,393
Total	**$13,928,352**	**$4,743,432**	**$2,548,018**	**$775,426**	**$3,458,407**	**$1,636,510**	**$761,555**	**$0**	**$5,005**
General Expenses									
Acct 5005 - Operation Supervision and Engineering	$17,006,071	$5,408,275	$2,902,206	$1,076,382	$4,764,331	$2,000,733	$847,787	$466	$5,891
Acct 5010 - Load Dispatching	$4,817,060	$1,531,923	$822,065	$304,891	$1,349,522	$566,718	$240,140	$132	$1,669
Acct 5085 - Miscellaneous Distribution Expense	$4,281,374	$1,361,564	$730,647	$270,985	$1,199,447	$503,696	$213,435	$117	$1,483
Acct 5105 - Maintenance Supervision and Engineering	$2,098,226	$667,278	$358,077	$132,805	$587,828	$246,852	$104,601	$57	$727
Total	**$28,202,730**	**$8,969,039**	**$4,812,995**	**$1,785,063**	**$7,901,128**	**$3,317,999**	**$1,405,964**	**$772**	**$9,769**
Secondary Conductors and Poles Gross Assets	$407,960,197	$210,539,997	$113,095,264	$15,163,285	$64,902,603	$4,036,913	$0	$0	$222,135
Acct 1815 - 1855	$1,859,448,991	$591,342,436	$317,328,089	$117,691,955	$520,933,423	$218,760,752	$92,697,331	$50,917	$644,087

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet

Ontario

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$3,784,046	$2,031,085	$983,238	$81,628	$644,503	$37,418	$0	$0	$6,174
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,209,173	$2,632,774	$831,705	$59,501	$470,533	$27,078	$1	$160,416	$27,165
Depreciation on Acct 1840-5 Secondary Underground Conduit	$8,276,596	$5,176,886	$1,635,401	$116,999	$925,221	$53,243	$1	$315,430	$53,415
Depreciation on Acct 1845-5 Secondary Underground Conductors	$4,319,142	$2,701,558	$853,434	$61,056	$482,827	$27,785	$1	$164,607	$27,875
Depreciation on General Plant Assigned to Secondary C&P	$3,650,473	$1,950,394	$956,720	$79,885	$622,524	$34,978	$0	$0	$5,972
Secondary C&P Operations and Maintenance	$5,053,278	$2,756,048	$1,334,189	$102,489	$807,467	$44,706	$0	$0	$8,377
Allocation of General Expenses	$6,540,610	$3,510,670	$1,699,498	$141,091	$1,114,005	$64,676	$0	$0	$10,671
Admin and General Assigned to Primary C&P	$1,630,330	$901,638	$413,950	$32,146	$264,914	$14,554	$0	$0	$3,128
PILs on Secondary C&P	$4,229,667	$2,270,272	$1,099,027	$91,240	$720,402	$41,824	$0	$0	$6,901
Debt Return on Secondary C&P	$7,659,279	$4,111,115	$1,990,170	$165,222	$1,304,538	$75,737	$0	$0	$12,496
Equity Return on Secondary C&P	$8,300,624	$4,455,356	$2,156,816	$179,057	$1,413,773	$82,079	$0	$0	$13,543
Total	**$57,653,217**	**$32,497,796**	**$13,954,149**	**$1,110,314**	**$8,770,709**	**$504,078**	**$2**	**$640,452**	**$175,717**
Secondary NCP	7,697,663	4,131,717	2,000,144	166,050	1,311,076	76,117	0	0	12,559
PLCC Amount	1,287,140	1,031,307	107,005	1,704	16,864	858	0	109,294	20,109
Adjustment to Customer Related Cost for PLCC	**$9,269,455**	**$8,111,691**	**$746,527**	**$11,394**	**$112,815**	**$5,679**	**$0**	**$0**	**$281,349**
General Plant - Gross Assets	$558,181,412	$281,622,790	$73,555,792	$12,544,073	$110,039,124	$40,753,068	$16,957,007	$19,603,947	$3,105,611
General Plant - Accumulated Depreciation	($357,714,605)	($180,480,007)	($47,138,763)	($8,038,960)	($70,519,370)	($26,116,899)	($10,867,021)	($12,563,331)	($1,990,253)
General Plant - Net Fixed Assets	$200,466,807	$101,142,783	$26,417,029	$4,505,113	$39,519,753	$14,636,169	$6,089,986	$7,040,615	$1,115,358
General Plant - Depreciation	$33,705,954	$17,005,878	$4,441,689	$757,478	$6,644,746	$2,460,886	$1,023,954	$1,183,790	$187,533
Total Net Fixed Assets Excluding General Plant	$1,647,880,007	$831,489,676	$214,325,525	$36,340,676	$322,997,729	$123,604,017	$52,390,799	$57,628,446	$9,103,139
Total Administration and General Expense	$50,136,382	$24,911,367	$7,602,828	$1,245,816	$9,624,133	$3,714,100	$1,592,202	$1,242,271	$203,664
Total O&M	$154,095,114	$76,146,904	$24,504,409	$3,971,964	$29,334,670	$11,408,810	$4,922,856	$3,259,987	$545,515
Secondary Conductors and Poles Gross Plant									
Acct 1830-5 Secondary Poles, Towers & Fixtures	$101,012,334	$54,218,325	$26,246,823	$2,178,988	$17,204,549	$998,843	$0	$0	$164,806
Acct 1835-5 Secondary Overhead Conductors	$74,226,937	$39,841,276	$19,286,965	$1,601,187	$12,642,426	$733,980	$0	$0	$121,104
Acct 1840-5 Secondary Underground Conduit	$175,346,032	$94,116,905	$45,561,529	$3,782,477	$29,865,159	$1,733,878	$0	$0	$286,084
Acct 1845-5 Secondary Underground Conductors	$81,521,149	$43,756,441	$21,182,277	$1,758,534	$13,884,786	$806,107	$0	$0	$133,005
Subtotal	***$432,106,452***	***$231,932,947***	***$112,277,593***	***$9,321,185***	***$73,596,919***	***$4,272,808***	***$0***	***$0***	***$704,999***
Secondary Conductors and Poles Accumulated Depreciation									
Acct 1830-5 Secondary Poles, Towers & Fixtures	($46,476,960)	($24,946,488)	($12,076,471)	($1,002,578)	($7,916,015)	($459,579)	$0	$0	($75,829)

Acct 1835-5 Secondary Overhead Conductors	($49,348,856)	($26,487,977)	($12,822,698)	($1,064,529)	($8,405,160)	($487,977)	$0	$0	($80,515)
Acct 1840-5 Secondary Underground Conduit	($113,460,983)	($60,900,133)	($29,481,453)	($2,447,524)	($19,324,819)	($1,121,939)	$0	$0	($185,116)
Acct 1845-5 Secondary Underground Conductors	($45,151,946)	($24,235,287)	($11,732,183)	($973,995)	($7,690,337)	($446,477)	$0	$0	($73,667)
Subtotal	***($254,438,746)***	***($136,569,884)***	***($66,112,806)***	***($5,488,626)***	***($43,336,330)***	***($2,515,972)***	***$0***	***$0***	***($415,127)***
Secondary Conductor & Pools - Net Fixed Assets	$177,667,706	$95,363,063	$46,164,787	$3,832,559	$30,260,589	$1,756,836	$0	$0	$289,872
General Plant Assigned to Secondary C&P - NFA	$21,711,259	$11,600,006	$5,690,113	$475,118	$3,702,475	$208,030	$0	$0	$35,516
Secondary C&P Net Fixed Assets Including General Plant	$199,378,966	$106,963,069	$51,854,901	$4,307,677	$33,963,064	$1,964,866	$0	$0	$325,389
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$113,816,109	$27,782,403	$13,449,324	$4,451,409	$36,961,464	$21,006,176	$10,080,884	$0	$84,449
Acct 1835-4 Primary Overhead Conductors	$83,635,541	$20,415,355	$9,882,972	$3,271,031	$27,160,408	$15,435,978	$7,407,740	$0	$62,056
Acct 1840-4 Primary Underground Conduit	$492,384,479	$120,190,579	$58,183,665	$19,257,420	$159,900,486	$90,875,670	$43,611,320	$0	$365,340
Acct 1845-4 Primary Underground Conductors	$228,917,347	$55,878,505	$27,050,508	$8,953,080	$74,340,270	$42,249,539	$20,275,594	$0	$169,852
Subtotal	***$918,753,475***	***$224,266,841***	***$108,566,469***	***$35,932,940***	***$298,362,628***	***$169,567,362***	***$81,375,538***	***$0***	***$681,697***
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$331,641	$126,588	$61,281	$10,236	$83,619	$33,970	$15,562	$0	$385
Acct 5025 Overhead Distribution Lines & Feeders - Other	$289,948	$110,674	$53,577	$8,949	$73,106	$29,700	$13,606	$0	$336
Acct 5040 Underground Distribution Lines & Feeders - Labour	$879,729	$282,348	$136,683	$30,355	$250,015	$122,012	$57,458	$0	$858
Acct 5045 Underground Distribution Lines & Feeders - Other	$1,385,783	$444,766	$215,309	$47,816	$393,832	$192,198	$90,509	$0	$1,352
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$4,942,817	$1,886,690	$913,337	$152,554	$1,246,263	$506,296	$231,943	$0	$5,735
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$2,813,097	$1,073,768	$519,806	$86,823	$709,283	$288,147	$132,005	$0	$3,264
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$4,661,694	$1,496,166	$724,287	$160,851	$1,324,830	$646,544	$304,468	$0	$4,548
Total	**$15,304,709**	**$5,421,001**	**$2,624,280**	**$497,582**	**$4,080,948**	**$1,818,868**	**$845,552**	**$0**	**$16,478**
General Expenses									
Acct 5005 - Operation Supervision and Engineering	$19,053,831	$6,321,092	$3,055,094	$703,013	$5,736,550	$2,260,920	$956,968	$781	$19,412
Acct 5010 - Load Dispatching	$4,980,928	$1,652,419	$798,643	$183,777	$1,499,612	$591,035	$250,164	$204	$5,075
Acct 5085 - Miscellaneous Distribution Expense	$3,984,372	$1,321,812	$638,855	$147,008	$1,199,578	$472,784	$200,113	$163	$4,059
Acct 5105 - Maintenance Supervision and Engineering	$2,093,221	$694,424	$335,627	$77,232	$630,208	$248,381	$105,131	$86	$2,133
Total	**$30,112,352**	**$9,989,748**	**$4,828,219**	**$1,111,031**	**$9,065,946**	**$3,573,120**	**$1,512,376**	**$1,234**	**$30,678**
Secondary Conductors and Poles Gross Assets	$432,106,452	$231,932,947	$112,277,593	$9,321,185	$73,596,919	$4,272,808	$0	$0	$704,999
Acct 1815 - 1855	$1,989,377,367	$659,974,284	$318,977,086	$73,400,415	$598,943,202	$236,058,743	$99,915,387	$81,494	$2,026,757

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet

Ontario

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$3,907,288	$2,084,511	$1,072,509	$24,034	$682,111	$37,961	$0	$0	$6,161
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,234,913	$2,652,903	$871,986	$17,048	$485,272	$26,766	$1	$154,703	$26,233
Depreciation on Acct 1840-5 Secondary Underground Conduit	$8,778,965	$5,499,462	$1,807,624	$35,341	$1,005,968	$55,487	$1	$320,700	$54,382
Depreciation on Acct 1845-5 Secondary Underground Conductors	$4,825,343	$3,022,770	$993,558	$19,425	$552,929	$30,498	$1	$176,272	$29,891
Depreciation on General Plant Assigned to Secondary C&P	$3,981,584	$2,113,537	$1,104,749	$24,911	$694,719	$37,357	$0	$0	$6,312
Secondary C&P Operations and Maintenance	$5,428,077	$2,940,451	$1,512,901	$31,341	$887,596	$47,096	$0	$0	$8,691
Allocation of General Expenses	$6,485,483	$3,459,961	$1,780,196	$39,893	$1,132,197	$63,009	$0	$0	$10,227
Admin and General Assigned to Primary C&P	$1,713,891	$938,658	$462,056	$8,900	$286,056	$15,089	$0	$0	$3,132
PILs on Secondary C&P	$3,996,887	$2,132,312	$1,097,103	$24,585	$697,753	$38,831	$0	$0	$6,303
Debt Return on Secondary C&P	$8,063,280	$4,301,705	$2,213,285	$49,598	$1,407,640	$78,338	$0	$0	$12,715
Equity Return on Secondary C&P	$8,756,838	$4,671,714	$2,403,659	$53,864	$1,528,717	$85,076	$0	$0	$13,809
Total	**$60,172,549**	**$33,817,985**	**$15,319,626**	**$328,941**	**$9,360,957**	**$515,507**	**$2**	**$651,675**	**$177,855**
Secondary NCP	7,876,281	4,201,943	2,161,955	48,448	1,374,994	76,521	0	0	12,420
PLCC Amount	9,079,281	5,289,805	2,268,872	48,555	1,287,194	76,542	0	108,313	0
Adjustment to Customer Related Cost for PLCC	**$68,259,064**	**$42,573,296**	**$16,077,238**	**$329,666**	**$8,763,214**	**$515,650**	**$0**	**$0**	**$0**
General Plant - Gross Assets	$608,985,853	$308,914,029	$82,648,824	$3,899,540	$126,253,744	$45,240,440	$18,866,818	$19,977,723	$3,184,735
General Plant - Accumulated Depreciation	($392,984,547)	($199,345,255)	($53,334,097)	($2,516,412)	($81,472,780)	($29,194,100)	($12,174,943)	($12,891,821)	($2,055,141)
General Plant - Net Fixed Assets	$216,001,306	$109,568,775	$29,314,727	$1,383,129	$44,780,964	$16,046,340	$6,691,875	$7,085,902	$1,129,594
General Plant - Depreciation	$37,524,065	$19,034,449	$5,092,598	$240,279	$7,779,415	$2,787,594	$1,162,522	$1,230,973	$196,235
Total Net Fixed Assets Excluding General Plant	$1,760,726,733	$892,876,546	$235,143,779	$11,026,054	$363,287,092	$134,726,046	$57,268,065	$57,288,835	$9,110,316
Total Administration and General Expense	$51,064,651	$25,723,351	$7,799,973	$489,694	$10,215,002	$3,796,873	$1,623,272	$1,216,456	$200,029
Total O&M	$160,353,857	$80,581,251	$25,539,329	$1,724,361	$31,695,918	$11,850,560	$5,090,713	$3,316,574	$555,151
Secondary Conductors and Poles Gross Plant									
Acct 1830-5 Secondary Poles, Towers & Fixtures	$105,041,443	$56,038,896	$28,832,759	$646,124	$18,337,512	$1,020,515	$0	$0	$165,639
Acct 1835-5 Secondary Overhead Conductors	$76,840,547	$40,993,909	$21,091,913	$472,656	$13,414,367	$746,533	$0	$0	$121,169
Acct 1840-5 Secondary Underground Conduit	$185,767,601	$99,105,752	$50,991,231	$1,142,681	$32,430,205	$1,804,798	$0	$0	$292,935
Acct 1845-5 Secondary Underground Conductors	$90,460,969	$48,260,312	$24,830,574	$556,437	$15,792,139	$878,861	$0	$0	$142,647
Subtotal	***$458,110,560***	***$244,398,868***	***$125,746,476***	***$2,817,897***	***$79,974,222***	***$4,450,707***	***$0***	***$0***	***$722,389***
Secondary Conductors and Poles Accumulated Depreciation									
Acct 1830-5 Secondary Poles, Towers & Fixtures	($50,322,627)	($26,846,779)	($13,813,026)	($309,541)	($8,785,025)	($488,902)	$0	$0	($79,353)
Acct 1835-5 Secondary Overhead Conductors	($52,093,184)	($27,791,359)	($14,299,025)	($320,432)	($9,094,119)	($506,104)	$0	$0	($82,145)

Acct 1840-5 Secondary Underground Conduit	($121,137,396)	($64,625,977)	($33,250,927)	($745,132)	($21,147,447)	($1,176,893)	$0	$0	($191,020)
Acct 1845-5 Secondary Underground Conductors	($48,720,360)	($25,991,981)	($13,373,221)	($299,685)	($8,505,311)	($473,336)	$0	$0	($76,827)
Subtotal	***($272,273,567)***	***($145,256,096)***	***($74,736,198)***	***($1,674,790)***	***($47,531,903)***	***($2,645,235)***	***$0***	***$0***	***($429,345)***
Secondary Conductor & Pools - Net Fixed Assets	$185,836,994	$99,142,772	$51,010,278	$1,143,107	$32,442,319	$1,805,473	$0	$0	$293,044
General Plant Assigned to Secondary C&P - NFA	$22,919,355	$12,166,242	$6,359,311	$143,394	$3,999,036	$215,038	$0	$0	$36,335
Secondary C&P Net Fixed Assets Including General Plant	$208,756,349	$111,309,014	$57,369,589	$1,286,501	$36,441,355	$2,020,511	$0	$0	$329,379
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$118,355,926	$29,327,776	$15,089,532	$1,344,300	$40,056,568	$21,920,228	$10,530,836	$0	$86,686
Acct 1835-4 Primary Overhead Conductors	$86,580,438	$21,454,031	$11,038,385	$983,391	$29,302,421	$16,035,217	$7,703,581	$0	$63,413
Acct 1840-4 Primary Underground Conduit	$521,649,007	$129,260,997	$66,506,506	$5,924,950	$176,547,718	$96,612,529	$46,414,239	$0	$382,067
Acct 1845-4 Primary Underground Conductors	$254,021,014	$62,944,641	$32,385,857	$2,885,200	$85,971,275	$47,046,217	$22,601,772	$0	$186,050
Subtotal	***$980,606,385***	***$242,987,445***	***$125,020,280***	***$11,137,840***	***$331,877,982***	***$181,614,191***	***$87,250,429***	***$0***	***$718,217***
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$398,333	$152,215	$78,317	$3,549	$104,121	$40,905	$18,777	$0	$450
Acct 5025 Overhead Distribution Lines & Feeders - Other	$304,859	$116,496	$59,939	$2,716	$79,687	$31,306	$14,371	$0	$344
Acct 5040 Underground Distribution Lines & Feeders - Labour	$949,945	$306,659	$157,780	$9,491	$280,623	$132,158	$62,327	$0	$906
Acct 5045 Underground Distribution Lines & Feeders - Other	$1,491,927	$481,621	$247,800	$14,905	$440,730	$207,560	$97,887	$0	$1,424
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$5,399,518	$2,063,314	$1,061,602	$48,109	$1,411,386	$554,478	$254,530	$0	$6,099
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$2,902,464	$1,109,116	$570,655	$25,860	$758,678	$298,055	$136,821	$0	$3,278
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$5,063,227	$1,634,500	$840,972	$50,585	$1,495,728	$704,407	$332,203	$0	$4,831
Total	**$16,510,274**	**$5,863,921**	**$3,017,066**	**$155,216**	**$4,570,954**	**$1,968,870**	**$916,916**	**$0**	**$17,332**
General Expenses									
Acct 5005 - Operation Supervision and Engineering	$18,984,710	$6,328,810	$3,245,833	$202,171	$5,953,830	$2,270,151	$963,618	$1,269	$19,028
Acct 5010 - Load Dispatching	$5,190,650	$1,730,373	$887,450	$55,276	$1,627,849	$620,687	$263,465	$347	$5,202
Acct 5085 - Miscellaneous Distribution Expense	$3,923,793	$1,308,049	$670,854	$41,785	$1,230,548	$469,199	$199,162	$262	$3,933
Acct 5105 - Maintenance Supervision and Engineering	$2,119,078	$706,423	$362,301	$22,566	$664,568	$253,395	$107,559	$142	$2,124
Total	**$30,218,231**	**$10,073,656**	**$5,166,438**	**$321,799**	**$9,476,796**	**$3,613,432**	**$1,533,804**	**$2,020**	**$30,287**
Secondary Conductors and Poles Gross Assets	$458,110,560	$244,398,868	$125,746,476	$2,817,897	$79,974,222	$4,450,707	$0	$0	$722,389
Acct 1815 - 1855	$2,134,504,121	$711,565,819	$364,938,055	$22,730,662	$669,405,807	$255,239,489	$108,342,251	$142,691	$2,139,347

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O3.3 Primary Conductors and Poles Cost Pool Worksheet

Ontario

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$6,159,699	$2,590,496	$680,990	$274,012	$1,238,289	$735,706	$353,127	$238,505	$48,574
Depreciation on Acct 1835-4 Primary Overhead Conductors	$4,468,209	$1,879,130	$493,986	$198,767	$898,247	$533,677	$256,156	$173,010	$35,236
Depreciation on Acct 1840-4 Primary Underground Conduit	$25,461,719	$10,708,069	$2,814,938	$1,132,655	$5,118,588	$3,041,114	$1,459,685	$985,884	$200,787
Depreciation on Acct 1845-4 Primary Underground Conductors	$10,821,565	$4,551,070	$1,196,386	$481,393	$2,175,467	$1,292,513	$620,385	$419,013	$85,337
Depreciation on General Plant Assigned to Primary C&P	$12,400,043	$5,228,773	$1,391,765	$560,208	$2,512,952	$1,446,324	$682,432	$479,831	$97,759
Primary C&P Operations and Maintenance	$14,420,978	$6,255,384	$1,673,294	$626,935	$2,826,300	$1,598,815	$761,839	$563,488	$114,922
Allocation of General Expenses	$18,982,828	$7,623,443	$2,121,993	$889,162	$4,017,474	$2,396,301	$1,150,018	$651,189	$133,249
Admin and General Assigned to Primary C&P	$4,860,499	$2,104,729	$536,110	$205,720	$952,268	$535,616	$254,066	$226,435	$45,556
PILs on Primary C&P	$16,324,299	$6,865,275	$1,804,744	$726,180	$3,281,686	$1,949,752	$935,850	$632,081	$128,731
Debt Return on Primary C&P	$27,415,918	$11,529,918	$3,030,986	$1,219,587	$5,511,442	$3,274,520	$1,571,717	$1,061,551	$216,198
Equity Return on Primary C&P	$26,184,612	$11,012,085	$2,894,858	$1,164,813	$5,263,911	$3,127,455	$1,501,128	$1,013,874	$206,488
Total	**$167,500,369**	**$70,348,371**	**$18,640,050**	**$7,479,431**	**$33,796,623**	**$19,931,793**	**$9,546,402**	**$6,444,860**	**$1,312,838**
General Plant - Gross Assets	$515,626,311	$252,800,034	$71,760,343	$20,401,261	$93,723,481	$37,553,874	$15,727,829	$19,627,858	$4,031,629
General Plant - Accumulated Depreciation	($327,142,327)	($160,390,557)	($45,528,797)	($12,943,707)	($59,463,447)	($23,826,290)	($9,978,619)	($12,453,017)	($2,557,892)
General Plant - Net Fixed Assets	$188,483,984	$92,409,477	$26,231,546	$7,457,554	$34,260,035	$13,727,585	$5,749,210	$7,174,841	$1,473,737
General Plant - Depreciation	$30,913,004	$15,155,954	$4,302,201	$1,223,103	$5,618,942	$2,251,443	$942,920	$1,176,736	$241,706
Total Net Fixed Assets Excluding General Plant	$1,503,330,620	$736,868,257	$206,580,333	$58,709,267	$271,716,303	$112,388,836	$47,881,760	$57,399,991	$11,785,874
Total Administration and General Expense	$48,663,412	$23,569,439	$7,713,646	$2,030,534	$8,677,110	$3,600,274	$1,543,228	$1,263,820	$265,360
Total O&M	$145,255,728	$70,049,830	$24,075,643	$6,188,069	$25,753,386	$10,746,822	$4,627,509	$3,145,050	$669,419
Primary Conductors and Poles Gross Assets									
Acct 1830-4 Primary Poles, Towers & Fixtures	$168,479,725	$70,855,092	$18,626,395	$7,494,757	$33,869,600	$20,122,992	$9,658,710	$6,523,573	$1,328,607
Acct 1835-4 Primary Overhead Conductors	$124,250,927	$52,254,423	$13,736,649	$5,527,255	$24,978,253	$14,840,364	$7,123,134	$4,811,024	$979,825
Acct 1840-4 Primary Underground Conduit	$716,852,704	$301,476,419	$79,252,155	$31,888,921	$144,109,413	$85,619,923	$41,096,176	$27,756,701	$5,652,996
Acct 1845-4 Primary Underground Conductors	$316,044,302	$132,914,201	$34,940,500	$14,059,111	$63,534,613	$37,747,907	$18,118,384	$12,237,308	$2,492,279
Subtotal	**$1,325,627,659**	**$557,500,135**	**$146,555,699**	**$58,970,043**	**$266,491,879**	**$158,331,186**	**$75,996,404**	**$51,328,606**	**$10,453,707**
Primary Conductors and Poles Accumulated Depreciation									
Acct 1830-4 Primary Poles, Towers & Fixtures	($78,218,304)	($32,895,146)	($8,647,480)	($3,479,512)	($15,724,282)	($9,342,289)	($4,484,147)	($3,028,631)	($616,818)
Acct 1835-4 Primary Overhead Conductors	($84,821,800)	($35,672,283)	($9,377,534)	($3,773,266)	($17,051,787)	($10,131,002)	($4,862,717)	($3,284,320)	($668,892)
Acct 1840-4 Primary Underground Conduit	($375,377,256)	($157,867,007)	($41,500,097)	($16,698,515)	($75,462,359)	($44,834,555)	($21,519,860)	($14,534,693)	($2,960,170)
Acct 1845-4 Primary Underground Conductors	($182,728,891)	($76,847,658)	($20,201,721)	($8,128,625)	($36,734,120)	($21,824,893)	($10,475,595)	($7,075,304)	($1,440,973)
Subtotal	**($721,146,251)**	**($303,282,094)**	**($79,726,832)**	**($32,079,917)**	**($144,972,548)**	**($86,132,739)**	**($41,342,319)**	**($27,922,948)**	**($5,686,854)**
Primary Conductor & Pools - Net Fixed Assets	$604,481,408	$254,218,041	$66,828,868	$26,890,126	$121,519,331	$72,198,447	$34,654,085	$23,405,658	$4,766,852
General Plant Assigned to Primary C&P - NFA	$75,606,031	$31,881,080	$8,485,922	$3,415,722	$15,322,071	$8,818,583	$4,160,950	$2,925,643	$596,060
Primary C&P Net Fixed Assets Including General Plant	$680,087,439	$286,099,121	$75,314,789	$30,305,849	$136,841,402	$81,017,030	$38,815,035	$26,331,301	$5,362,912
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0

Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$149,526,551	$90,867,231	$31,358,798	$3,647,771	$15,610,210	$962,601	$21	$5,858,104	$1,221,816
Acct 1835-5 Secondary Overhead Conductors	$110,273,284	$67,013,035	$23,126,579	$2,690,169	$11,512,264	$709,902	$16	$4,320,252	$901,068
Acct 1840-5 Secondary Underground Conduit	$255,282,777	$155,135,251	$53,538,057	$6,227,745	$26,650,904	$1,643,423	$36	$10,001,388	$2,085,974
Acct 1845-5 Secondary Underground Conductors	$112,548,459	$68,395,658	$23,603,730	$2,745,673	$11,749,787	$724,549	$16	$4,409,388	$919,659
Subtotal	**$627,631,072**	**$381,411,175**	**$131,627,163**	**$15,311,359**	**$65,523,164**	**$4,040,475**	**$88**	**$24,589,131**	**$5,128,517**
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour									
Acct 5025 Overhead Distribution Lines & Feeders - Other									
Acct 5040 Underground Distribution Lines & Feeders - Labour									
Acct 5045 Underground Distribution Lines & Feeders - Other									
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid									
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid									
Acct 5120 Maintenance of Poles, Towers & Fixtures									
Acct 5125 Maintenance of Overhead Conductors & Devices									
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way									
Acct 5145 Maintenance of Underground Conduit									
Acct 5150 Maintenance of Underground Conductors & Devices									
Total	**$21,428,233**	**$10,534,977**	**$3,176,142**	**$789,716**	**$3,521,211**	**$1,639,615**	**$761,840**	**$833,429**	**$171,303**
General Expenses									
Acct 5005 - Operation Supervision and Engineering									
Acct 5010 - Load Dispatching									
Acct 5085 - Miscellaneous Distribution Expense									
Acct 5105 - Maintenance Supervision and Engineering									
Total	**$43,388,816**	**$20,296,883**	**$6,357,668**	**$1,840,636**	**$8,155,108**	**$3,354,841**	**$1,422,652**	**$1,626,620**	**$334,408**
Primary Conductors and Poles Gross Assets	$1,325,627,659	$557,500,135	$146,555,699	$58,970,043	$266,491,879	$158,331,186	$75,996,404	$51,328,606	$10,453,707
Acct 1815 - 1855	$3,056,553,094	$1,484,305,152	$439,093,114	$122,072,723	$540,954,414	$221,664,938	$94,012,858	$128,214,852	$26,235,043

Grouping of Operation and Maintenance	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 6,959,506	$ 3,539,262	$ 1,093,916	$ 243,852	$ 1,082,856	$ 461,454	$ 211,379	$ 270,971	$ 55,815
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 6,606,423	$ 3,103,034	$ 902,414	$ 259,033	$ 1,160,450	$ 593,023	$ 279,281	$ 256,596	$ 52,592
1830 & 1835	$ 5,141,671	$ 2,614,801	$ 808,184	$ 180,158	$ 800,012	$ 340,922	$ 156,167	$ 200,193	$ 41,236
1840 & 1845	$ 2,720,633	$ 1,277,880	$ 371,629	$ 106,674	$ 477,892	$ 244,217	$ 115,012	$ 105,670	$ 21,658
Total	**$ 21,428,233**	**$ 10,534,977**	**$ 3,176,142**	**$ 789,716**	**$ 3,521,211**	**$ 1,639,615**	**$ 761,840**	**$ 833,429**	**$ 171,303**

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O3.3 Primary Conductors and Poles Cost Pool Worksheet

Ontario

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$6,344,749	$2,741,643	$667,345	$164,162	$1,367,656	$762,594	$365,409	$239,051	$36,889
Depreciation on Acct 1835-4 Primary Overhead Conductors	$4,534,387	$1,959,364	$476,930	$117,321	$977,420	$545,001	$261,146	$170,842	$26,363
Depreciation on Acct 1840-4 Primary Underground Conduit	$26,574,366	$11,483,107	$2,795,108	$687,576	$5,728,294	$3,194,052	$1,530,481	$1,001,242	$154,506
Depreciation on Acct 1845-4 Primary Underground Conductors	$12,031,214	$5,198,834	$1,265,451	$311,292	$2,593,414	$1,446,067	$692,906	$453,300	$69,951
Depreciation on General Plant Assigned to Primary C&P	$13,032,449	$5,644,937	$1,392,292	$344,473	$2,832,446	$1,528,475	$718,970	$494,350	$76,505
Primary C&P Operations and Maintenance	$15,885,969	$7,072,530	$1,749,475	$401,949	$3,341,230	$1,777,513	$845,857	$603,751	$93,665
Allocation of General Expenses	$20,246,769	$8,384,728	$2,150,743	$550,782	$4,582,260	$2,563,805	$1,228,067	$679,612	$106,773
Admin and General Assigned to Primary C&P	$5,196,110	$2,313,770	$542,798	$126,072	$1,096,192	$578,663	$273,576	$230,069	$34,969
PILs on Primary C&P	$15,206,109	$6,570,744	$1,599,388	$393,438	$3,277,785	$1,827,667	$875,756	$572,921	$88,410
Debt Return on Primary C&P	$27,535,936	$11,898,613	$2,896,247	$712,455	$5,935,567	$3,309,626	$1,585,860	$1,037,472	$160,097
Equity Return on Primary C&P	$29,841,639	$12,894,935	$3,138,762	$772,112	$6,432,578	$3,586,755	$1,718,651	$1,124,344	$173,502
Total	**$176,429,699**	**$76,163,204**	**$18,674,538**	**$4,581,632**	**$38,164,841**	**$21,120,219**	**$10,096,680**	**$6,606,953**	**$1,021,631**
General Plant - Gross Assets	$558,181,412	$281,622,790	$73,555,792	$12,544,073	$110,039,124	$40,753,068	$16,957,007	$19,603,947	$3,105,611
General Plant - Accumulated Depreciation	($357,714,605)	($180,480,007)	($47,138,763)	($8,038,960)	($70,519,370)	($26,116,899)	($10,867,021)	($12,563,331)	($1,990,253)
General Plant - Net Fixed Assets	$200,466,807	$101,142,783	$26,417,029	$4,505,113	$39,519,753	$14,636,169	$6,089,986	$7,040,615	$1,115,358
General Plant - Depreciation	$33,705,954	$17,005,878	$4,441,689	$757,478	$6,644,746	$2,460,886	$1,023,954	$1,183,790	$187,533
Total Net Fixed Assets Excluding General Plant	$1,647,880,007	$831,489,676	$214,325,525	$36,340,676	$322,997,729	$123,604,017	$52,390,799	$57,628,446	$9,103,139
Total Administration and General Expense	$50,136,382	$24,911,367	$7,602,828	$1,245,816	$9,624,133	$3,714,100	$1,592,202	$1,242,271	$203,664
Total O&M	$154,095,114	$76,146,904	$24,504,409	$3,971,964	$29,334,670	$11,408,810	$4,922,856	$3,259,987	$545,515
Primary Conductors and Poles Gross Assets									
Acct 1830-4 Primary Poles, Towers & Fixtures	$175,101,706	$75,663,575	$18,417,306	$4,530,522	$37,744,420	$21,045,993	$10,084,524	$6,597,308	$1,018,060
Acct 1835-4 Primary Overhead Conductors	$128,670,062	$55,599,898	$13,533,597	$3,329,165	$27,735,748	$15,465,236	$7,410,415	$4,847,902	$748,101
Acct 1840-4 Primary Underground Conduit	$757,514,583	$327,331,258	$79,675,852	$19,599,673	$163,287,663	$91,047,921	$43,627,067	$28,540,879	$4,404,271
Acct 1845-4 Primary Underground Conductors	$352,180,533	$152,181,488	$37,042,566	$9,112,199	$75,915,022	$42,329,621	$20,282,915	$13,269,107	$2,047,615
Subtotal	**$1,413,466,885**	**$610,776,219**	**$148,669,320**	**$36,571,559**	**$304,682,854**	**$169,888,770**	**$81,404,920**	**$53,255,196**	**$8,218,047**
Primary Conductors and Poles Accumulated Depreciation									
Acct 1830-4 Primary Poles, Towers & Fixtures	($84,667,123)	($36,585,693)	($8,905,340)	($2,190,648)	($18,250,601)	($10,176,392)	($4,876,181)	($3,190,003)	($492,264)
Acct 1835-4 Primary Overhead Conductors	($89,532,800)	($38,688,211)	($9,417,115)	($2,316,541)	($19,299,433)	($10,761,212)	($5,156,407)	($3,373,328)	($520,553)
Acct 1840-4 Primary Underground Conduit	($403,505,059)	($174,359,440)	($42,440,911)	($10,440,152)	($86,978,389)	($48,498,468)	($23,238,816)	($15,202,861)	($2,346,022)
Acct 1845-4 Primary Underground Conductors	($197,027,321)	($85,137,900)	($20,723,455)	($5,097,817)	($42,470,642)	($23,681,297)	($11,347,272)	($7,423,399)	($1,145,538)
Subtotal	**($774,732,303)**	**($334,771,244)**	**($81,486,822)**	**($20,045,159)**	**($166,999,066)**	**($93,117,370)**	**($44,618,676)**	**($29,189,591)**	**($4,504,376)**
Primary Conductor & Pools - Net Fixed Assets	$638,734,582	$276,004,975	$67,182,498	$16,526,400	$137,683,788	$76,771,401	$36,786,244	$24,065,605	$3,713,671

General Plant Assigned to Primary C&P - NFA	$77,510,742	$33,573,371	$8,280,684	$2,048,759	$16,846,030	$9,090,636	$4,276,089	$2,940,157	$455,016
Primary C&P Net Fixed Assets Including General Plant	$716,245,324	$309,578,346	$75,463,182	$18,575,159	$154,529,818	$85,862,037	$41,062,333	$27,005,762	$4,168,687
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$155,403,590	$97,202,610	$30,706,721	$2,196,802	$17,372,198	$999,713	$21	$5,922,590	$1,002,935
Acct 1835-5 Secondary Overhead Conductors	$114,195,288	$71,427,436	$22,564,233	$1,614,277	$12,765,619	$734,620	$16	$4,352,099	$736,987
Acct 1840-5 Secondary Underground Conduit	$269,763,127	$168,732,782	$53,303,409	$3,813,401	$30,156,178	$1,735,390	$37	$10,280,949	$1,740,981
Acct 1845-5 Secondary Underground Conductors	$125,417,152	$78,446,544	$24,781,599	$1,772,911	$14,020,085	$806,810	$17	$4,779,776	$809,410
Subtotal	**$664,779,157**	**$415,809,372**	**$131,355,963**	**$9,397,391**	**$74,314,080**	**$4,276,534**	**$91**	**$25,335,414**	**$4,290,313**
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour									
Acct 5025 Overhead Distribution Lines & Feeders - Other									
Acct 5040 Underground Distribution Lines & Feeders - Labour									
Acct 5045 Underground Distribution Lines & Feeders - Other									
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid									
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid									
Acct 5120 Maintenance of Poles, Towers & Fixtures									
Acct 5125 Maintenance of Overhead Conductors & Devices									
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way									
Acct 5145 Maintenance of Underground Conduit									
Acct 5150 Maintenance of Underground Conductors & Devices									
Total	**$23,545,706**	**$11,887,427**	**$3,295,213**	**$505,234**	**$4,156,177**	**$1,822,257**	**$845,858**	**$890,977**	**$142,564**
General Expenses									
Acct 5005 - Operation Supervision and Engineering									
Acct 5010 - Load Dispatching									
Acct 5085 - Miscellaneous Distribution Expense									
Acct 5105 - Maintenance Supervision and Engineering									
Total	**$46,326,696**	**$22,243,387**	**$6,425,936**	**$1,142,050**	**$9,391,597**	**$3,631,898**	**$1,540,145**	**$1,682,619**	**$269,065**
Primary Conductors and Poles Gross Assets	$1,413,466,885	$610,776,219	$148,669,320	$36,571,559	$304,682,854	$169,888,770	$81,404,920	$53,255,196	$8,218,047
Acct 1815 - 1855	$3,260,099,427	$1,620,294,955	$444,190,504	$75,831,417	$624,464,482	$240,665,180	$102,091,600	$131,852,101	$20,709,187

Grouping of Operation and Maintenance

	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 7,604,333	$ 3,977,341	$ 1,130,256	$ 154,784	$ 1,268,134	$ 507,232	$ 232,027	$ 288,060	$ 46,499
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,171,837	$ 3,463,222	$ 928,382	$ 163,456	$ 1,350,509	$ 647,757	$ 304,578	$ 271,031	$ 42,902
1830 & 1835	$ 5,284,132	$ 2,763,791	$ 785,397	$ 107,557	$ 881,207	$ 352,468	$ 161,232	$ 200,169	$ 32,312
1840 & 1845	$ 3,485,403	$ 1,683,073	$ 451,179	$ 79,437	$ 656,327	$ 314,800	$ 148,020	$ 131,717	$ 20,850
Total	**$ 23,545,706**	**$ 11,887,427**	**$ 3,295,213**	**$ 505,234**	**$ 4,156,177**	**$ 1,822,257**	**$ 845,858**	**$ 890,977**	**$ 142,564**

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O3.3 Primary Conductors and Poles Cost Pool Worksheet

Ontario

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$6,550,534	$2,867,043	$720,929	$49,067	$1,471,195	$790,026	$378,977	$236,684	$36,613
Depreciation on Acct 1835-4 Primary Overhead Conductors	$4,555,016	$1,993,643	$501,309	$34,120	$1,023,018	$549,357	$263,527	$164,582	$25,459
Depreciation on Acct 1840-4 Primary Underground Conduit	$28,263,682	$12,370,472	$3,110,603	$211,712	$6,347,787	$3,408,736	$1,635,176	$1,021,224	$157,973
Depreciation on Acct 1845-4 Primary Underground Conductors	$13,445,614	$5,884,887	$1,479,777	$100,716	$3,019,772	$1,621,606	$777,887	$485,817	$75,151
Depreciation on General Plant Assigned to Primary C&P	$14,397,876	$6,320,893	$1,614,707	$110,582	$3,258,086	$1,690,498	$795,604	$525,948	$81,558
Primary C&P Operations and Maintenance	$17,172,410	$7,742,327	$1,979,944	$125,642	$3,758,701	$1,925,288	$917,232	$625,931	$97,346
Allocation of General Expenses	$20,293,130	$8,542,653	$2,262,222	$159,349	$4,767,255	$2,567,480	$1,231,119	$659,316	$103,737
Admin and General Assigned to Primary C&P	$5,497,246	$2,471,525	$604,695	$35,681	$1,211,359	$616,855	$292,477	$229,580	$35,075
PILs on Primary C&P	$14,570,075	$6,377,042	$1,603,532	$109,138	$3,272,317	$1,757,221	$842,942	$526,446	$81,436
Debt Return on Primary C&P	$29,393,520	$12,864,980	$3,234,949	$220,175	$6,601,539	$3,545,000	$1,700,542	$1,062,047	$164,288
Equity Return on Primary C&P	$31,921,787	$13,971,554	$3,513,201	$239,113	$7,169,366	$3,849,921	$1,846,814	$1,153,399	$178,419
Total	**$186,060,891**	**$81,407,020**	**$20,625,868**	**$1,395,294**	**$41,900,395**	**$22,321,988**	**$10,682,297**	**$6,690,975**	**$1,037,055**
General Plant - Gross Assets	$608,985,853	$308,914,029	$82,648,824	$3,899,540	$126,253,744	$45,240,440	$18,866,818	$19,977,723	$3,184,735
General Plant - Accumulated Depreciation	($392,984,547)	($199,345,255)	($53,334,097)	($2,516,412)	($81,472,780)	($29,194,100)	($12,174,943)	($12,891,821)	($2,055,141)
General Plant - Net Fixed Assets	$216,001,306	$109,568,775	$29,314,727	$1,383,129	$44,780,964	$16,046,340	$6,691,875	$7,085,902	$1,129,594
General Plant - Depreciation	$37,524,065	$19,034,449	$5,092,598	$240,279	$7,779,415	$2,787,594	$1,162,522	$1,230,973	$196,235
Total Net Fixed Assets Excluding General Plant	$1,760,726,733	$892,876,546	$235,143,779	$11,026,054	$363,287,092	$134,726,046	$57,268,065	$57,288,835	$9,110,316
Total Administration and General Expense	$51,064,651	$25,723,351	$7,799,973	$489,694	$10,215,002	$3,796,873	$1,623,272	$1,216,456	$200,029
Total O&M	$160,353,857	$80,581,251	$25,539,329	$1,724,361	$31,695,918	$11,850,560	$5,090,713	$3,316,574	$555,151
Primary Conductors and Poles Gross Assets									
Acct 1830-4 Primary Poles, Towers & Fixtures	$182,086,041	$79,695,569	$20,039,756	$1,363,931	$40,895,001	$21,960,454	$10,534,466	$6,579,137	$1,017,726
Acct 1835-4 Primary Overhead Conductors	$133,200,674	$58,299,381	$14,659,603	$997,751	$29,915,757	$16,064,643	$7,706,236	$4,812,810	$744,493
Acct 1840-4 Primary Underground Conduit	$802,536,933	$351,255,028	$88,324,423	$6,011,473	$180,243,080	$96,789,820	$46,430,238	$28,997,285	$4,485,586
Acct 1845-4 Primary Underground Conductors	$390,801,560	$171,046,350	$43,010,260	$2,927,333	$87,770,761	$47,132,551	$22,609,563	$14,120,452	$2,184,291
Subtotal	**$1,508,625,208**	**$660,296,328**	**$166,034,043**	**$11,300,489**	**$338,824,599**	**$181,947,467**	**$87,280,503**	**$54,509,684**	**$8,432,095**
Primary Conductors and Poles Accumulated Depreciation									
Acct 1830-4 Primary Poles, Towers & Fixtures	($91,311,040)	($39,965,091)	($10,049,375)	($683,973)	($20,507,696)	($11,012,551)	($5,282,739)	($3,299,253)	($510,361)
Acct 1835-4 Primary Overhead Conductors	($94,286,862)	($41,267,552)	($10,376,884)	($706,264)	($21,176,040)	($11,371,450)	($5,454,903)	($3,406,775)	($526,994)
Acct 1840-4 Primary Underground Conduit	($433,063,427)	($189,543,559)	($47,661,454)	($3,243,899)	($97,262,422)	($52,229,535)	($25,054,595)	($15,647,459)	($2,420,503)
Acct 1845-4 Primary Underground Conductors	($212,522,006)	($93,016,807)	($23,389,433)	($1,591,915)	($47,730,664)	($25,631,178)	($12,295,319)	($7,678,851)	($1,187,840)
Subtotal	**($831,183,335)**	**($363,793,009)**	**($91,477,147)**	**($6,226,051)**	**($186,676,823)**	**($100,244,714)**	**($48,087,556)**	**($30,032,337)**	**($4,645,698)**
Primary Conductor & Pools - Net Fixed Assets	$677,441,873	$296,503,319	$74,556,896	$5,074,437	$152,147,776	$81,702,753	$39,192,947	$24,477,347	$3,786,397

General Plant Assigned to Primary C&P - NFA	$82,879,082	$36,385,215	$9,294,803	$636,547	$18,754,655	$9,731,082	$4,579,765	$3,027,537	$469,478
Primary C&P Net Fixed Assets Including General Plant	$760,320,955	$332,888,534	$83,851,699	$5,710,984	$170,902,431	$91,433,835	$43,772,712	$27,504,884	$4,255,875
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$161,602,220	$101,233,486	$33,274,553	$650,554	$18,517,755	$1,021,394	$21	$5,903,404	$1,001,052
Acct 1835-5 Secondary Overhead Conductors	$118,216,226	$74,054,928	$24,341,201	$475,897	$13,546,219	$747,177	$16	$4,318,493	$732,296
Acct 1840-5 Secondary Underground Conduit	$285,796,310	$179,033,164	$58,846,620	$1,150,517	$32,748,968	$1,806,354	$38	$10,440,271	$1,770,378
Acct 1845-5 Secondary Underground Conductors	$139,170,721	$87,181,582	$28,655,816	$560,253	$15,947,363	$879,618	$18	$5,083,971	$862,099
Subtotal	**$704,785,477**	**$441,503,160**	**$145,118,191**	**$2,837,221**	**$80,760,304**	**$4,454,543**	**$93**	**$25,746,139**	**$4,365,826**
Operations and Maintenance									
Acct 5020 Overhead Distribution Lines & Feeders - Labour									
Acct 5025 Overhead Distribution Lines & Feeders - Other									
Acct 5040 Underground Distribution Lines & Feeders - Labour									
Acct 5045 Underground Distribution Lines & Feeders - Other									
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid									
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid									
Acct 5120 Maintenance of Poles, Towers & Fixtures									
Acct 5125 Maintenance of Overhead Conductors & Devices									
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way									
Acct 5145 Maintenance of Underground Conduit									
Acct 5150 Maintenance of Underground Conductors & Devices									
Total	**$25,400,421**	**$12,919,187**	**$3,710,468**	**$157,187**	**$4,654,603**	**$1,972,424**	**$917,233**	**$921,572**	**$147,748**
General Expenses									
Acct 5005 - Operation Supervision and Engineering									
Acct 5010 - Load Dispatching									
Acct 5085 - Miscellaneous Distribution Expense									
Acct 5105 - Maintenance Supervision and Engineering									
Total	**$46,489,586**	**$22,500,316**	**$6,699,054**	**$329,459**	**$9,833,270**	**$3,683,676**	**$1,567,479**	**$1,616,965**	**$259,368**
Primary Conductors and Poles Gross Assets	$1,508,625,208	$660,296,328	$166,034,043	$11,300,489	$338,824,599	$181,947,467	$87,280,503	$54,509,684	$8,432,095
Acct 1815 - 1855	$3,480,001,440	$1,739,140,790	$491,671,849	$23,364,121	$698,883,066	$261,048,047	$111,126,859	$133,684,353	$21,082,355

Grouping of Operation and Maintenance

	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 8,306,950	$ 4,373,058	$ 1,288,608	$ 48,690	$ 1,436,007	$ 555,472	$ 254,619	$ 301,703	$ 48,794
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,789,580	$ 3,795,457	$ 1,053,354	$ 51,261	$ 1,524,458	$ 705,687	$ 332,318	$ 282,268	$ 44,776
1830 & 1835	$ 5,547,164	$ 2,920,214	$ 860,498	$ 32,514	$ 958,928	$ 370,929	$ 170,028	$ 201,470	$ 32,583
1840 & 1845	$ 3,756,727	$ 1,830,458	$ 508,007	$ 24,722	$ 735,210	$ 340,336	$ 160,269	$ 136,131	$ 21,594
Total	**$ 25,400,421**	**$ 12,919,187**	**$ 3,710,468**	**$ 157,187**	**$ 4,654,603**	**$ 1,972,424**	**$ 917,233**	**$ 921,572**	**$ 147,748**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O3.4 Secondary Cost Pool Worksheet

Ontario

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$5,650,396	$3,433,744	$1,185,004	$137,844	$589,888	$36,375	$1	$221,369	$46,171
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,142,994	$2,517,696	$868,871	$101,070	$432,519	$26,671	$1	$162,313	$33,853
Depreciation on Acct 1840-5 Secondary Underground Conduit	$7,978,128	$4,848,305	$1,673,178	$194,630	$832,897	$51,360	$1	$312,565	$65,191
Depreciation on Acct 1845-5 Secondary Underground Conductors	$3,885,749	$2,361,368	$814,922	$94,795	$405,663	$25,015	$1	$152,235	$31,751
Depreciation on General Plant Assigned to Secondary C&P	$5,416,678	$3,281,253	$1,146,569	$133,421	$566,744	$33,855	$1	$210,845	$43,992
Secondary C&P Operations and Maintenance	$7,007,255	$4,279,593	$1,502,848	$162,781	$694,911	$40,800	$1	$269,941	$56,380
Allocation of General Expenses	$8,778,519	$5,215,543	$1,905,841	$230,868	$987,788	$61,152	$1	$311,954	$65,371
Admin and General Assigned to Primary C&P	$2,353,485	$1,439,941	$481,501	$53,415	$234,137	$13,668	$0	$108,474	$22,349
PILs on Secondary C&P	$7,089,391	$4,308,220	$1,486,791	$172,949	$740,115	$45,639	$1	$277,746	$57,929
Debt Return on Secondary C&P	$11,906,309	$7,235,460	$2,496,998	$290,460	$1,242,990	$76,649	$2	$466,462	$97,289
Equity Return on Secondary C&P	$11,371,572	$6,910,500	$2,384,853	$277,415	$1,187,165	$73,206	$2	$445,512	$92,920
Total	**$75,580,477**	**$45,831,624**	**$15,947,376**	**$1,849,648**	**$7,914,816**	**$484,392**	**$11**	**$2,939,415**	**$613,197**
General Plant - Gross Assets	$515,626,311	$252,800,034	$71,760,343	$20,401,261	$93,723,481	$37,553,874	$15,727,829	$19,627,858	$4,031,629
General Plant - Accumulated Depreciation	($327,142,327)	($160,390,557)	($45,528,797)	($12,943,707)	($59,463,447)	($23,826,290)	($9,978,619)	($12,453,017)	($2,557,892)
General Plant - Net Fixed Assets	$188,483,984	$92,409,477	$26,231,546	$7,457,554	$34,260,035	$13,727,585	$5,749,210	$7,174,841	$1,473,737
General Plant - Depreciation	$30,913,004	$15,155,954	$4,302,201	$1,223,103	$5,618,942	$2,251,443	$942,920	$1,176,736	$241,706
Total Net Fixed Assets Excluding General Plant	**$1,503,330,620**	**$736,868,257**	**$206,580,333**	**$58,709,267**	**$271,716,303**	**$112,388,836**	**$47,881,760**	**$57,399,991**	**$11,785,874**
Total Administration and General Expense	**$48,663,412**	**$23,569,439**	**$7,713,646**	**$2,030,534**	**$8,677,110**	**$3,600,274**	**$1,543,228**	**$1,263,820**	**$265,360**
Total O&M	**$145,255,728**	**$70,049,830**	**$24,075,643**	**$6,188,069**	**$25,753,386**	**$10,746,822**	**$4,627,509**	**$3,145,050**	**$669,419**
Secondary Conductors and Poles Gross Plant									
Acct 1830-5 Secondary Poles, Towers & Fixtures	$149,526,551	$90,867,231	$31,358,798	$3,647,771	$15,610,210	$962,601	$21	$5,858,104	$1,221,816
Acct 1835-5 Secondary Overhead Conductors	$110,273,284	$67,013,035	$23,126,579	$2,690,169	$11,512,264	$709,902	$16	$4,320,252	$901,068
Acct 1840-5 Secondary Underground Conduit	$255,282,777	$155,135,251	$53,538,057	$6,227,745	$26,650,904	$1,643,423	$36	$10,001,388	$2,085,974
Acct 1845-5 Secondary Underground Conductors	$112,548,459	$68,395,658	$23,603,730	$2,745,673	$11,749,787	$724,549	$16	$4,409,388	$919,659
Subtotal	***$627,631,072***	***$381,411,175***	***$131,627,163***	***$15,311,359***	***$65,523,164***	***$4,040,475***	***$88***	***$24,589,131***	***$5,128,517***
Secondary Conductors and Poles Accumulated Depreciation									
Acct 1830-5 Secondary Poles, Towers & Fixtures	($65,767,014)	($39,966,590)	($13,792,697)	($1,604,418)	($6,865,917)	($423,386)	($9)	($2,576,599)	($537,397)
Acct 1835-5 Secondary Overhead Conductors	($71,745,233)	($43,599,552)	($15,046,453)	($1,750,259)	($7,490,029)	($461,871)	($10)	($2,810,812)	($586,247)
Acct 1840-5 Secondary Underground Conduit	($163,196,107)	($99,174,215)	($34,225,585)	($3,981,247)	($17,037,278)	($1,050,601)	($23)	($6,393,645)	($1,333,513)
Acct 1845-5 Secondary Underground Conductors	($64,405,790)	($39,139,375)	($13,507,221)	($1,571,210)	($6,723,809)	($414,623)	($9)	($2,523,270)	($526,274)
Subtotal	***($365,114,144)***	***($221,879,733)***	***($76,571,957)***	***($8,907,133)***	***($38,117,033)***	***($2,350,480)***	***($51)***	***($14,304,326)***	***($2,983,431)***
Secondary Conductor & Pools - Net Fixed Assets	$262,516,927	$159,531,442	$55,055,207	$6,404,225	$27,406,132	$1,689,994	$37	$10,284,805	$2,145,086
General Plant Assigned to Secondary C&P - NFA	$33,026,783	$20,006,585	$6,990,904	$813,498	$3,455,571	$206,422	$4	$1,285,572	$268,227

Secondary C&P Net Fixed Assets Including General Plant	$295,543,711	$179,538,026	$62,046,111	$7,217,723	$30,861,703	$1,896,417	$41	$11,570,377	$2,413,313
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$168,479,725	$70,855,092	$18,626,395	$7,494,757	$33,869,600	$20,122,992	$9,658,710	$6,523,573	$1,328,607
Acct 1835-4 Primary Overhead Conductors	$124,250,927	$52,254,423	$13,736,649	$5,527,255	$24,978,253	$14,840,364	$7,123,134	$4,811,024	$979,825
Acct 1840-4 Primary Underground Conduit	$716,852,704	$301,476,419	$79,252,155	$31,888,921	$144,109,413	$85,619,923	$41,096,176	$27,756,701	$5,652,996
Acct 1845-4 Primary Underground Conductors	$316,044,302	$132,914,201	$34,940,500	$14,059,111	$63,534,613	$37,747,907	$18,118,384	$12,237,308	$2,492,279
Subtotal	***$1,325,627,659***	***$557,500,135***	***$146,555,699***	***$58,970,043***	***$266,491,879***	***$158,331,186***	***$75,996,404***	***$51,328,606***	***$10,453,707***
Operations and Maintenance									
Total	**$21,428,233**	**$10,534,977**	**$3,176,142**	**$789,716**	**$3,521,211**	**$1,639,615**	**$761,840**	**$833,429**	**$171,303**
General Expenses									
Total	**$43,388,816**	**$20,296,883**	**$6,357,668**	**$1,840,636**	**$8,155,108**	**$3,354,841**	**$1,422,652**	**$1,626,620**	**$334,408**
Secondary Conductors and Poles Gross Assets	$627,631,072	$381,411,175	$131,627,163	$15,311,359	$65,523,164	$4,040,475	$88	$24,589,131	$5,128,517
Acct 1815 - 1855	$3,056,553,094	$1,484,305,152	$439,093,114	$122,072,723	$540,954,414	$221,664,938	$94,012,858	$128,214,852	$26,235,043

Grouping of Operation and Maintenance

	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 6,959,506	$ 3,539,262	$ 1,093,916	$ 243,852	$ 1,082,856	$ 461,454	$ 211,379	$ 270,971	$ 55,815
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 6,606,423	$ 3,103,034	$ 902,414	$ 259,033	$ 1,160,450	$ 593,023	$ 279,281	$ 256,596	$ 52,592
1830 & 1835	$ 5,141,671	$ 2,614,801	$ 808,184	$ 180,158	$ 800,012	$ 340,922	$ 156,167	$ 200,193	$ 41,236
1840 & 1845	$ 2,720,633	$ 1,277,880	$ 371,629	$ 106,674	$ 477,892	$ 244,217	$ 115,012	$ 105,670	$ 21,658
Total	**$ 21,428,233**	**$ 10,534,977**	**$ 3,176,142**	**$ 789,716**	**$ 3,521,211**	**$ 1,639,615**	**$ 761,840**	**$ 833,429**	**$ 171,303**

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O3.4 Secondary Cost Pool Worksheet

Ontario

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$5,821,609	$3,641,329	$1,150,311	$82,295	$650,784	$37,450	$1	$221,867	$37,571
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,209,173	$2,632,774	$831,705	$59,501	$470,533	$27,078	$1	$160,416	$27,165
Depreciation on Acct 1840-5 Secondary Underground Conduit	$8,276,596	$5,176,886	$1,635,401	$116,999	$925,221	$53,243	$1	$315,430	$53,415
Depreciation on Acct 1845-5 Secondary Underground Conductors	$4,319,142	$2,701,558	$853,434	$61,056	$482,827	$27,785	$1	$164,607	$27,875
Depreciation on General Plant Assigned to Secondary C&P	$5,610,418	$3,496,666	$1,119,288	$80,538	$628,590	$35,008	$1	$213,985	$36,341
Secondary C&P Operations and Maintenance	$7,659,737	$4,814,897	$1,545,739	$103,284	$814,947	$44,745	$1	$287,226	$48,899
Allocation of General Expenses	$9,311,269	$5,708,225	$1,900,277	$141,528	$1,117,642	$64,538	$1	$323,316	$55,742
Admin and General Assigned to Primary C&P	$2,496,813	$1,575,188	$479,587	$32,395	$267,368	$14,566	$0	$109,452	$18,256
PILs on Secondary C&P	$6,507,180	$4,070,143	$1,285,776	$91,986	$727,422	$41,861	$1	$247,995	$41,996
Debt Return on Secondary C&P	$11,783,507	$7,370,406	$2,328,343	$166,573	$1,317,250	$75,803	$2	$449,081	$76,048
Equity Return on Secondary C&P	$12,770,191	$7,987,562	$2,523,305	$180,521	$1,427,549	$82,151	$2	$486,685	$82,416
Total	**$78,765,632**	**$49,175,635**	**$15,653,164**	**$1,116,677**	**$8,830,134**	**$504,228**	**$11**	**$2,980,060**	**$505,722**
General Plant - Gross Assets	$558,181,412	$281,622,790	$73,555,792	$12,544,073	$110,039,124	$40,753,068	$16,957,007	$19,603,947	$3,105,611
General Plant - Accumulated Depreciation	($357,714,605)	($180,480,007)	($47,138,763)	($8,038,960)	($70,519,370)	($26,116,899)	($10,867,021)	($12,563,331)	($1,990,253)
General Plant - Net Fixed Assets	$200,466,807	$101,142,783	$26,417,029	$4,505,113	$39,519,753	$14,636,169	$6,089,986	$7,040,615	$1,115,358
General Plant - Depreciation	$33,705,954	$17,005,878	$4,441,689	$757,478	$6,644,746	$2,460,886	$1,023,954	$1,183,790	$187,533
Total Net Fixed Assets Excluding General Plant	**$1,647,880,007**	**$831,489,676**	**$214,325,525**	**$36,340,676**	**$322,997,729**	**$123,604,017**	**$52,390,799**	**$57,628,446**	**$9,103,139**
Total Administration and General Expense	**$50,136,382**	**$24,911,367**	**$7,602,828**	**$1,245,816**	**$9,624,133**	**$3,714,100**	**$1,592,202**	**$1,242,271**	**$203,664**
Total O&M	**$154,095,114**	**$76,146,904**	**$24,504,409**	**$3,971,964**	**$29,334,670**	**$11,408,810**	**$4,922,856**	**$3,259,987**	**$545,515**
Secondary Conductors and Poles Gross Plant									
Acct 1830-5 Secondary Poles, Towers & Fixtures	$155,403,590	$97,202,610	$30,706,721	$2,196,802	$17,372,198	$999,713	$21	$5,922,590	$1,002,935
Acct 1835-5 Secondary Overhead Conductors	$114,195,288	$71,427,436	$22,564,233	$1,614,277	$12,765,619	$734,620	$16	$4,352,099	$736,987
Acct 1840-5 Secondary Underground Conduit	$269,763,127	$168,732,782	$53,303,409	$3,813,401	$30,156,178	$1,735,390	$37	$10,280,949	$1,740,981
Acct 1845-5 Secondary Underground Conductors	$125,417,152	$78,446,544	$24,781,599	$1,772,911	$14,020,085	$806,810	$17	$4,779,776	$809,410
Subtotal	***$664,779,157***	***$415,809,372***	***$131,355,963***	***$9,397,391***	***$74,314,080***	***$4,276,534***	***$91***	***$25,335,414***	***$4,290,313***
Secondary Conductors and Poles Accumulated Depreciation									
Acct 1830-5 Secondary Poles, Towers & Fixtures	($71,503,016)	($44,724,062)	($14,128,523)	($1,010,774)	($7,993,152)	($459,980)	($10)	($2,725,053)	($461,462)
Acct 1835-5 Secondary Overhead Conductors	($75,921,317)	($47,487,643)	($15,001,550)	($1,073,232)	($8,487,063)	($488,403)	($10)	($2,893,439)	($489,977)
Acct 1840-5 Secondary Underground Conduit	($174,555,359)	($109,181,754)	($34,490,984)	($2,467,534)	($19,513,128)	($1,122,917)	($24)	($6,652,483)	($1,126,535)
Acct 1845-5 Secondary Underground Conductors	($69,464,532)	($43,449,021)	($13,725,732)	($981,958)	($7,765,275)	($446,866)	($10)	($2,647,364)	($448,306)
Subtotal	***($391,444,224)***	***($244,842,479)***	***($77,346,789)***	***($5,533,499)***	***($43,758,618)***	***($2,518,166)***	***($54)***	***($14,918,340)***	***($2,526,280)***
Secondary Conductor & Pools - Net Fixed Assets	$273,334,933	$170,966,893	$54,009,174	$3,863,893	$30,555,462	$1,758,367	$37	$10,417,074	$1,764,033
General Plant Assigned to Secondary C&P - NFA	$33,368,066	$20,796,491	$6,656,986	$479,002	$3,738,554	$208,211	$4	$1,272,681	$216,137

Secondary C&P Net Fixed Assets Including General Plant	$306,702,999	$191,763,383	$60,666,160	$4,342,895	$34,294,015	$1,966,579	$42	$11,689,755	$1,980,170
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$175,101,706	$75,663,575	$18,417,306	$4,530,522	$37,744,420	$21,045,993	$10,084,524	$6,597,308	$1,018,060
Acct 1835-4 Primary Overhead Conductors	$128,670,062	$55,599,898	$13,533,597	$3,329,165	$27,735,748	$15,465,236	$7,410,415	$4,847,902	$748,101
Acct 1840-4 Primary Underground Conduit	$757,514,583	$327,331,258	$79,675,852	$19,599,673	$163,287,663	$91,047,921	$43,627,067	$28,540,879	$4,404,271
Acct 1845-4 Primary Underground Conductors	$352,180,533	$152,181,488	$37,042,566	$9,112,199	$75,915,022	$42,329,621	$20,282,915	$13,269,107	$2,047,615
Subtotal	***$1,413,466,885***	***$610,776,219***	***$148,669,320***	***$36,571,559***	***$304,682,854***	***$169,888,770***	***$81,404,920***	***$53,255,196***	***$8,218,047***
Operations and Maintenance									
Total	**$23,545,706**	**$11,887,427**	**$3,295,213**	**$505,234**	**$4,156,177**	**$1,822,257**	**$845,858**	**$890,977**	**$142,564**
General Expenses									
Total	**$46,326,696**	**$22,243,387**	**$6,425,936**	**$1,142,050**	**$9,391,597**	**$3,631,898**	**$1,540,145**	**$1,682,619**	**$269,065**
Secondary Conductors and Poles Gross Assets	$664,779,157	$415,809,372	$131,355,963	$9,397,391	$74,314,080	$4,276,534	$91	$25,335,414	$4,290,313
Acct 1815 - 1855	$3,260,099,427	$1,620,294,955	$444,190,504	$75,831,417	$624,464,482	$240,665,180	$102,091,600	$131,852,101	$20,709,187

Grouping of Operation and Maintenance

	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 7,604,333	$ 3,977,341	$ 1,130,256	$ 154,784	$ 1,268,134	$ 507,232	$ 232,027	$ 288,060	$ 46,499
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,171,837	$ 3,463,222	$ 928,382	$ 163,456	$ 1,350,509	$ 647,757	$ 304,578	$ 271,031	$ 42,902
1830 & 1835	$ 5,284,132	$ 2,763,791	$ 785,397	$ 107,557	$ 881,207	$ 352,468	$ 161,232	$ 200,169	$ 32,312
1840 & 1845	$ 3,485,403	$ 1,683,073	$ 451,179	$ 79,437	$ 656,327	$ 314,800	$ 148,020	$ 131,717	$ 20,850
Total	**$ 23,545,706**	**$ 11,887,427**	**$ 3,295,213**	**$ 505,234**	**$ 4,156,177**	**$ 1,822,257**	**$ 845,858**	**$ 890,977**	**$ 142,564**

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O3.4 Secondary Cost Pool Worksheet

Ontario

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$6,011,212	$3,765,641	$1,237,733	$24,199	$688,816	$37,993	$1	$219,592	$37,237
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$4,234,913	$2,652,903	$871,986	$17,048	$485,272	$26,766	$1	$154,703	$26,233
Depreciation on Acct 1840-5 Secondary Underground Conduit	$8,778,965	$5,499,462	$1,807,624	$35,341	$1,005,968	$55,487	$1	$320,700	$54,382
Depreciation on Acct 1845-5 Secondary Underground Conductors	$4,825,343	$3,022,770	$993,558	$19,425	$552,929	$30,498	$1	$176,272	$29,891
Depreciation on General Plant Assigned to Secondary C&P	$6,119,597	$3,818,076	$1,274,940	$25,081	$701,547	$37,389	$1	$224,415	$38,148
Secondary C&P Operations and Maintenance	$8,228,012	$5,176,860	$1,730,524	$31,545	$895,902	$47,136	$1	$295,641	$50,402
Allocation of General Expenses	$9,293,520	$5,711,993	$1,977,243	$40,008	$1,136,296	$62,859	$1	$311,410	$53,711
Admin and General Assigned to Primary C&P	$2,620,480	$1,652,570	$528,520	$8,958	$288,733	$15,102	$0	$108,436	$18,161
PILs on Secondary C&P	$6,149,058	$3,851,992	$1,266,116	$24,754	$704,611	$38,865	$1	$224,628	$38,091
Debt Return on Secondary C&P	$12,405,046	$7,770,970	$2,554,249	$49,938	$1,421,476	$78,405	$2	$453,162	$76,844
Equity Return on Secondary C&P	$13,472,059	$8,439,386	$2,773,952	$54,234	$1,543,743	$85,149	$2	$492,141	$83,453
Total	**$82,138,204**	**$51,362,624**	**$17,016,444**	**$330,532**	**$9,425,293**	**$515,649**	**$11**	**$2,981,100**	**$506,552**
General Plant - Gross Assets	$608,985,853	$308,914,029	$82,648,824	$3,899,540	$126,253,744	$45,240,440	$18,866,818	$19,977,723	$3,184,735
General Plant - Accumulated Depreciation	($392,984,547)	($199,345,255)	($53,334,097)	($2,516,412)	($81,472,780)	($29,194,100)	($12,174,943)	($12,891,821)	($2,055,141)
General Plant - Net Fixed Assets	$216,001,306	$109,568,775	$29,314,727	$1,383,129	$44,780,964	$16,046,340	$6,691,875	$7,085,902	$1,129,594
General Plant - Depreciation	$37,524,065	$19,034,449	$5,092,598	$240,279	$7,779,415	$2,787,594	$1,162,522	$1,230,973	$196,235
Total Net Fixed Assets Excluding General Plant	**$1,760,726,733**	**$892,876,546**	**$235,143,779**	**$11,026,054**	**$363,287,092**	**$134,726,046**	**$57,268,065**	**$57,288,835**	**$9,110,316**
Total Administration and General Expense	**$51,064,651**	**$25,723,351**	**$7,799,973**	**$489,694**	**$10,215,002**	**$3,796,873**	**$1,623,272**	**$1,216,456**	**$200,029**
Total O&M	**$160,353,857**	**$80,581,251**	**$25,539,329**	**$1,724,361**	**$31,695,918**	**$11,850,560**	**$5,090,713**	**$3,316,574**	**$555,151**
Secondary Conductors and Poles Gross Plant									
Acct 1830-5 Secondary Poles, Towers & Fixtures	$161,602,220	$101,233,486	$33,274,553	$650,554	$18,517,755	$1,021,394	$21	$5,903,404	$1,001,052
Acct 1835-5 Secondary Overhead Conductors	$118,216,226	$74,054,928	$24,341,201	$475,897	$13,546,219	$747,177	$16	$4,318,493	$732,296
Acct 1840-5 Secondary Underground Conduit	$285,796,310	$179,033,164	$58,846,620	$1,150,517	$32,748,968	$1,806,354	$38	$10,440,271	$1,770,378
Acct 1845-5 Secondary Underground Conductors	$139,170,721	$87,181,582	$28,655,816	$560,253	$15,947,363	$879,618	$18	$5,083,971	$862,099
Subtotal	***$704,785,477***	***$441,503,160***	***$145,118,191***	***$2,837,221***	***$80,760,304***	***$4,454,543***	***$93***	***$25,746,139***	***$4,365,826***
Secondary Conductors and Poles Accumulated Depreciation									
Acct 1830-5 Secondary Poles, Towers & Fixtures	($77,419,426)	($48,498,334)	($15,940,974)	($311,664)	($8,871,375)	($489,324)	($10)	($2,828,167)	($479,578)
Acct 1835-5 Secondary Overhead Conductors	($80,143,359)	($50,204,704)	($16,501,843)	($322,629)	($9,183,507)	($506,540)	($11)	($2,927,674)	($496,452)
Acct 1840-5 Secondary Underground Conduit	($186,365,224)	($116,745,929)	($38,373,356)	($750,242)	($21,355,310)	($1,177,907)	($24)	($6,808,008)	($1,154,448)
Acct 1845-5 Secondary Underground Conductors	($74,954,401)	($46,954,153)	($15,433,415)	($301,740)	($8,588,912)	($473,744)	($10)	($2,738,119)	($464,308)
Subtotal	***($418,882,410)***	***($262,403,120)***	***($86,249,589)***	***($1,686,275)***	***($47,999,103)***	***($2,647,514)***	***($55)***	***($15,301,968)***	***($2,594,786)***
Secondary Conductor & Pools - Net Fixed Assets	$285,903,067	$179,100,041	$58,868,602	$1,150,946	$32,761,201	$1,807,028	$38	$10,444,171	$1,771,040
General Plant Assigned to Secondary C&P - NFA	$35,226,486	$21,978,147	$7,338,986	$144,377	$4,038,344	$215,223	$4	$1,291,812	$219,592
Secondary C&P Net Fixed Assets Including General Plant	$321,129,553	$201,078,188	$66,207,589	$1,295,323	$36,799,545	$2,022,252	$42	$11,735,983	$1,990,632
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0

Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$182,086,041	$79,695,569	$20,039,756	$1,363,931	$40,895,001	$21,960,454	$10,534,466	$6,579,137	$1,017,726
Acct 1835-4 Primary Overhead Conductors	$133,200,674	$58,299,381	$14,659,603	$997,751	$29,915,757	$16,064,643	$7,706,236	$4,812,810	$744,493
Acct 1840-4 Primary Underground Conduit	$802,536,933	$351,255,028	$88,324,423	$6,011,473	$180,243,080	$96,789,820	$46,430,238	$28,997,285	$4,485,586
Acct 1845-4 Primary Underground Conductors	$390,801,560	$171,046,350	$43,010,260	$2,927,333	$87,770,761	$47,132,551	$22,609,563	$14,120,452	$2,184,291
Subtotal	***$1,508,625,208***	***$660,296,328***	***$166,034,043***	***$11,300,489***	***$338,824,599***	***$181,947,467***	***$87,280,503***	***$54,509,684***	***$8,432,095***
Operations and Maintenance									
Total	**$25,400,421**	**$12,919,187**	**$3,710,468**	**$157,187**	**$4,654,603**	**$1,972,424**	**$917,233**	**$921,572**	**$147,748**
General Expenses									
Total	**$46,489,586**	**$22,500,316**	**$6,699,054**	**$329,459**	**$9,833,270**	**$3,683,676**	**$1,567,479**	**$1,616,965**	**$259,368**
Secondary Conductors and Poles Gross Assets	$704,785,477	$441,503,160	$145,118,191	$2,837,221	$80,760,304	$4,454,543	$93	$25,746,139	$4,365,826
Acct 1815 - 1855	$3,480,001,440	$1,739,140,790	$491,671,849	$23,364,121	$698,883,066	$261,048,047	$111,126,859	$133,684,353	$21,082,355

Grouping of Operation and Maintenance	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 8,306,950	$ 4,373,058	$ 1,288,608	$ 48,690	$ 1,436,007	$ 555,472	$ 254,619	$ 301,703	$ 48,794
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,789,580	$ 3,795,457	$ 1,053,354	$ 51,261	$ 1,524,458	$ 705,687	$ 332,318	$ 282,268	$ 44,776
1830 & 1835	$ 5,547,164	$ 2,920,214	$ 860,498	$ 32,514	$ 958,928	$ 370,929	$ 170,028	$ 201,470	$ 32,583
1840 & 1845	$ 3,756,727	$ 1,830,458	$ 508,007	$ 24,722	$ 735,210	$ 340,336	$ 160,269	$ 136,131	$ 21,594
Total	**$ 25,400,421**	**$ 12,919,187**	**$ 3,710,468**	**$ 157,187**	**$ 4,654,603**	**$ 1,972,424**	**$ 917,233**	**$ 921,572**	**$ 147,748**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Lii
EB-2007-0680
Sheet O4 Summary of Allocators by Class & Accounts

Grouping by Allocator	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1808	$ 21,423,746	$ 5,357,420	$ 2,354,631	$ 1,212,897	$ 6,657,015	$ 3,889,265	$ 1,831,312	$ 82,756	$ 38,450
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,138,314	$ 1,430,574	$ 768,458	$ 411,303	$ 1,859,534	$ 1,125,752	$ 541,185	$ -	$ 1,509
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 6,959,506	$ 3,539,262	$ 1,093,916	$ 243,852	$ 1,082,856	$ 461,454	$ 211,379	$ 270,971	$ 55,815
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 6,606,423	$ 3,103,034	$ 902,414	$ 259,033	$ 1,160,450	$ 593,023	$ 279,281	$ 256,596	$ 52,592
1850	$ 1,742,721	$ 807,799	$ 261,015	$ 98,268	$ 420,508	$ 77,639	$ 7,445	$ 58,040	$ 12,008
1855	$ 284,291	$ 198,148	$ 42,981	$ 1,717	$ 7,196	$ 41	$ 3	$ 28,514	$ 5,690
1860	$ 795,836	$ 537,740	$ 66,147	$ 18,733	$ 147,387	$ 23,274	$ 2,553	$ -	$ -
1815-1855	$ 43,388,816	$ 20,296,883	$ 6,357,668	$ 1,840,636	$ 8,155,108	$ 3,354,841	$ 1,422,652	$ 1,626,620	$ 334,408
1830 & 1835	$ 5,141,671	$ 2,614,801	$ 808,184	$ 180,158	$ 800,012	$ 340,922	$ 156,167	$ 200,193	$ 41,236
1840 & 1845	$ 2,720,633	$ 1,277,880	$ 371,629	$ 106,674	$ 477,892	$ 244,217	$ 115,012	$ 105,670	$ 21,658
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,000,000	$ 3,933,327	$ 1,881,934	$ 801,603	$ 131,541	$ 251,595	$ -	$ -	$ -
Break Out	-$ 1,991,067,124	-$ 983,723,893	-$ 281,745,036	-$ 78,720,558	-$ 356,688,831	-$ 138,786,722	-$ 57,264,096	-$ 78,129,749	-$ 16,008,239
CCA	$ 4,652,874	$ 3,576,982	$ 387,943	$ 12,374	$ 54,777	$ 3,060	$ 284	$ 514,744	$ 102,709
CDMPP	$ 15,443,114	$ 7,447,469	$ 2,559,644	$ 657,895	$ 2,738,016	$ 1,142,567	$ 491,982	$ 334,371	$ 71,170
CEN	$ 260,301,626	$ 55,544,414	$ 26,014,938	$ 13,784,005	$ 85,716,858	$ 51,381,714	$ 26,161,341	$ 1,112,985	$ 585,370
CEN EWMP	$ 1,675,016,978	$ 360,615,680	$ 168,898,974	$ 89,491,059	$ 556,506,785	$ 333,589,833	$ 154,888,270	$ 7,225,928	$ 3,800,447
CREV	-$ 510,276,035	-$ 199,876,295	-$ 69,517,532	-$ 22,458,325	-$ 129,952,515	-$ 61,290,349	-$ 23,987,572	-$ 1,884,920	-$ 1,308,527
CWCS	$ 316,671,669	$ 220,717,657	$ 47,876,037	$ 1,912,698	$ 8,015,909	$ 46,011	$ 3,425	$ 31,762,263	$ 6,337,670
CWMC	$ 202,597,599	$ 136,893,645	$ 16,839,289	$ 4,768,989	$ 37,520,691	$ 5,925,031	$ 649,954	$ -	$ -
CWMR	$ 2,970,310	$ 2,122,450	$ 821,157	$ 26,703	$ -	$ -	$ -	$ -	$ -
CWNB	$ 19,241,830	$ 11,244,280	$ 4,878,011	$ 544,580	$ 2,410,692	$ 134,678	$ 26,783	$ 619	$ 2,186
DCP	$ 48,867,458	$ 12,220,248	$ 5,370,903	$ 2,766,611	$ 15,184,618	$ 8,871,394	$ 4,177,214	$ 188,767	$ 87,703
LPHA	-$ 5,000,000	-$ 2,740,702	-$ 1,101,152	-$ 734,944	-$ 192,582	-$ 197,409	-$ 33,211	$ -	$ -
LTNCP	$ 613,420,551	$ 284,337,188	$ 91,874,742	$ 34,589,418	$ 148,014,602	$ 27,328,231	$ 2,620,442	$ 20,429,352	$ 4,226,576
NFA	$ 40,072,714	$ 19,641,927	$ 5,506,596	$ 1,564,952	$ 7,242,858	$ 2,995,832	$ 1,276,334	$ 1,530,052	$ 314,164
NFA ECC	$ 520,805,891	$ 255,339,466	$ 72,481,192	$ 20,606,196	$ 94,664,955	$ 37,931,111	$ 15,885,819	$ 19,825,025	$ 4,072,128
O&M	$ 35,912,762	$ 17,318,992	$ 5,952,418	$ 1,529,927	$ 6,367,220	$ 2,657,025	$ 1,144,097	$ 777,576	$ 165,506
PNCP	$ 1,472,882,881	$ 591,818,909	$ 164,990,632	$ 68,837,004	$ 311,101,207	$ 185,337,444	$ 88,979,163	$ 51,328,606	$ 10,489,915
SNCP	$ 627,631,072	$ 381,411,175	$ 131,627,163	$ 15,311,359	$ 65,523,164	$ 4,040,475	$ 88	$ 24,589,131	$ 5,128,517
TCP	$ 15,115,982	$ 3,780,042	$ 1,661,361	$ 855,785	$ 4,696,999	$ 2,744,154	$ 1,292,121	$ 58,390	$ 27,129
Total	**$ 3,467,464,107**	**$ 1,220,786,502**	**$ 410,286,256**	**$ 160,520,602**	**$ 879,824,924**	**$ 474,216,104**	**$ 220,879,426**	**$ 82,292,501**	**$ 18,657,792**

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Li
EB-2007-0680
Sheet O4 Summary of Allocators by Class & Accounts

Grouping by Allocator	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1808	$ 21,954,295	$ 5,856,984	$ 2,303,404	$ 620,374	$ 7,227,288	$ 3,942,493	$ 1,880,072	$ 84,468	$ 39,210
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,574,793	$ 1,604,901	$ 776,924	$ 257,144	$ 2,135,146	$ 1,213,460	$ 582,340	$ -	$ 4,878
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 7,604,333	$ 3,977,341	$ 1,130,256	$ 154,784	$ 1,268,134	$ 507,232	$ 232,027	$ 288,060	$ 46,499
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,171,837	$ 3,463,222	$ 928,382	$ 163,456	$ 1,350,509	$ 647,757	$ 304,578	$ 271,031	$ 42,902
1850	$ 1,905,326	$ 911,077	$ 270,622	$ 62,642	$ 495,541	$ 85,385	$ 8,174	$ 61,740	$ 10,144
1855	$ 296,397	$ 210,485	$ 43,678	$ 872	$ 8,209	$ 43	$ 3	$ 29,002	$ 4,104
1860	$ 852,362	$ 571,237	$ 83,491	$ 9,240	$ 162,463	$ 23,402	$ 2,529	$ -	$ -
1815-1855	$ 46,326,696	$ 22,243,387	$ 6,425,936	$ 1,142,050	$ 9,391,597	$ 3,631,898	$ 1,540,145	$ 1,682,619	$ 269,065
1830 & 1835	$ 5,284,132	$ 2,763,791	$ 785,397	$ 107,557	$ 881,207	$ 352,468	$ 161,232	$ 200,169	$ 32,312
1840 & 1845	$ 3,485,403	$ 1,683,073	$ 451,179	$ 79,437	$ 656,327	$ 314,800	$ 148,020	$ 131,717	$ 20,850
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -
Break Out	-$ 2,161,750,784	-$ 1,098,005,200	-$ 291,731,209	-$ 49,053,018	-$ 416,013,841	-$ 150,630,762	-$ 61,901,982	-$ 81,570,654	-$ 12,844,117
CCA	$ 4,739,803	$ 3,703,111	$ 384,222	$ 6,119	$ 60,553	$ 3,079	$ 282	$ 510,233	$ 72,205
CDMPP	$ 15,880,934	$ 7,847,646	$ 2,525,407	$ 409,348	$ 3,023,210	$ 1,175,784	$ 507,346	$ 335,972	$ 56,220
CEN	$ 270,082,798	$ 58,835,361	$ 26,975,458	$ 6,942,588	$ 94,968,659	$ 53,382,718	$ 27,211,768	$ 1,157,231	$ 609,015
CEN EWMP	$ 1,674,844,260	$ 368,110,524	$ 168,775,205	$ 43,437,140	$ 594,182,852	$ 333,995,407	$ 155,292,405	$ 7,240,353	$ 3,810,373
CREV	-$ 545,873,066	-$ 226,304,371	-$ 74,315,256	-$ 11,229,728	-$ 141,189,575	-$ 61,791,541	-$ 24,911,702	-$ 4,316,459	-$ 1,814,433
CWCS	$ 324,780,992	$ 230,642,004	$ 47,861,203	$ 955,875	$ 8,995,572	$ 46,731	$ 3,427	$ 31,779,009	$ 4,497,171
CWMC	$ 288,651,558	$ 193,448,871	$ 28,274,124	$ 3,129,178	$ 55,017,823	$ 7,925,175	$ 856,386	$ -	$ -
CWMR	$ 2,621,397	$ 1,902,180	$ 707,451	$ 11,766	$ -	$ -	$ -	$ -	$ -
CWNB	$ 19,803,717	$ 11,779,176	$ 4,888,663	$ 272,474	$ 2,696,594	$ 137,132	$ 26,864	$ 621	$ 2,193
DCP	$ 52,119,288	$ 13,904,426	$ 5,468,260	$ 1,472,761	$ 17,157,514	$ 9,359,442	$ 4,463,274	$ 200,527	$ 93,084
LPHA	-$ 5,000,000	-$ 2,740,702	-$ 1,101,152	-$ 734,943	-$ 192,583	-$ 197,409	-$ 33,211	$ -	$ -
LTNCP	$ 657,630,797	$ 314,461,807	$ 93,406,127	$ 21,621,274	$ 171,037,984	$ 29,470,929	$ 2,821,419	$ 21,309,870	$ 3,501,387
NFA	$ 34,739,625	$ 17,528,970	$ 4,518,283	$ 766,112	$ 6,809,246	$ 2,605,746	$ 1,104,472	$ 1,214,889	$ 191,907
NFA ECC	$ 563,473,630	$ 284,292,906	$ 74,253,188	$ 12,663,006	$ 111,082,424	$ 41,139,455	$ 17,117,780	$ 19,789,815	$ 3,135,056
O&M	$ 37,049,047	$ 18,307,980	$ 5,891,589	$ 954,978	$ 7,052,927	$ 2,743,017	$ 1,183,601	$ 783,798	$ 131,158
PNCP	$ 1,570,461,559	$ 649,098,468	$ 167,220,931	$ 42,711,704	$ 355,666,436	$ 198,864,087	$ 95,310,202	$ 53,255,196	$ 8,334,534
SNCP	$ 664,779,157	$ 415,809,372	$ 131,355,963	$ 9,397,391	$ 74,314,080	$ 4,276,534	$ 91	$ 25,335,414	$ 4,290,313
TCP	$ 23,115,982	$ 6,166,900	$ 2,425,286	$ 653,200	$ 7,609,712	$ 4,151,106	$ 1,979,554	$ 88,938	$ 41,285
Total	**$ 3,601,106,269**	**$ 1,316,289,207**	**$ 412,999,369**	**$ 87,843,642**	**$ 975,996,945**	**$ 487,645,135**	**$ 225,891,096**	**$ 79,863,559**	**$ 14,577,317**

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Li
EB-2007-0680
Sheet O4 Summary of Allocators by Class & Accounts

Grouping by Allocator	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
1808	$ 22,661,092	$ 6,210,127	$ 2,476,022	$ 146,817	$ 7,729,823	$ 4,062,603	$ 1,907,629	$ 87,555	$ 40,516
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,971,478	$ 1,727,484	$ 888,813	$ 79,183	$ 2,359,438	$ 1,291,160	$ 620,294	$ -	$ 5,106
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 8,306,950	$ 4,373,058	$ 1,288,608	$ 48,690	$ 1,436,007	$ 555,472	$ 254,619	$ 301,703	$ 48,794
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,789,580	$ 3,795,457	$ 1,053,354	$ 51,261	$ 1,524,458	$ 705,687	$ 332,318	$ 282,268	$ 44,776
1850	$ 2,082,925	$ 1,007,731	$ 312,265	$ 19,850	$ 565,353	$ 93,385	$ 8,950	$ 64,718	$ 10,673
1855	$ 308,503	$ 222,467	$ 43,729	$ 218	$ 8,872	$ 43	$ 3	$ 29,059	$ 4,112
1860	$ 897,312	$ 607,095	$ 86,279	$ 2,306	$ 175,321	$ 23,775	$ 2,536	$ -	$ -
1815-1855	$ 46,489,586	$ 22,500,316	$ 6,699,054	$ 329,459	$ 9,833,270	$ 3,683,676	$ 1,567,479	$ 1,616,965	$ 259,368
1830 & 1835	$ 5,547,164	$ 2,920,214	$ 860,498	$ 32,514	$ 958,928	$ 370,929	$ 170,028	$ 201,470	$ 32,583
1840 & 1845	$ 3,756,727	$ 1,830,458	$ 508,007	$ 24,722	$ 735,210	$ 340,336	$ 160,269	$ 136,131	$ 21,594
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -
Break Out	-$ 2,333,819,965	-$ 1,197,390,465	-$ 326,130,284	-$ 15,149,572	-$ 467,787,584	-$ 163,050,429	-$ 67,071,994	-$ 83,980,760	-$ 13,258,876
CCA	$ 5,770,991	$ 4,560,985	$ 448,261	$ 1,778	$ 75,923	$ 3,643	$ 329	$ 595,765	$ 84,309
CDMPP	$ 16,249,461	$ 8,165,702	$ 2,588,028	$ 174,738	$ 3,211,906	$ 1,200,877	$ 515,867	$ 336,085	$ 56,256
CEN	$ 276,592,690	$ 62,057,980	$ 27,617,686	$ 1,637,096	$ 100,868,338	$ 54,700,737	$ 27,900,191	$ 1,186,222	$ 624,439
CEN EWMP	$ 1,676,227,553	$ 358,865,919	$ 171,897,858	$ 405,030,271	$ 240,566,019	$ 333,232,293	$ 155,917,626	$ 7,149,432	$ 3,568,135
CREV	-$ 574,181,854	-$ 249,235,384	-$ 76,828,016	-$ 2,666,282	-$ 149,686,141	-$ 62,746,060	-$ 25,602,538	-$ 5,373,464	-$ 2,043,969
CWCS	$ 333,287,980	$ 240,339,125	$ 47,241,802	$ 235,627	$ 9,585,095	$ 46,766	$ 3,385	$ 31,393,556	$ 4,442,624
CWMC	$ 331,074,774	$ 223,995,430	$ 31,833,633	$ 850,734	$ 64,687,027	$ 8,772,250	$ 935,701	$ -	$ -
CWMR	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -
CWNB	$ 20,255,542	$ 12,311,908	$ 4,840,134	$ 67,181	$ 2,869,255	$ 137,657	$ 26,619	$ 616	$ 2,173
DCP	$ 53,948,246	$ 14,784,171	$ 5,894,555	$ 349,520	$ 18,402,042	$ 9,671,657	$ 4,541,407	$ 208,439	$ 96,454
LPHA	-$ 5,000,000	-$ 2,740,702	-$ 1,101,152	-$ 734,944	-$ 192,582	-$ 197,409	-$ 33,211	$ -	$ -
LTNCP	$ 700,832,948	$ 339,067,063	$ 105,066,533	$ 6,678,870	$ 190,221,770	$ 31,420,976	$ 3,011,410	$ 21,775,348	$ 3,590,978
NFA	$ 30,725,227	$ 15,580,973	$ 4,103,332	$ 192,408	$ 6,339,472	$ 2,351,011	$ 999,345	$ 999,708	$ 158,978
NFA ECC	$ 614,357,593	$ 311,638,897	$ 83,377,853	$ 3,933,937	$ 127,367,402	$ 45,639,496	$ 19,033,238	$ 20,153,942	$ 3,212,827
O&M	$ 37,663,941	$ 18,926,938	$ 5,998,682	$ 405,018	$ 7,444,743	$ 2,783,462	$ 1,195,707	$ 778,998	$ 130,394
PNCP	$ 1,676,898,112	$ 701,993,184	$ 187,487,631	$ 13,211,752	$ 395,775,148	$ 213,112,619	$ 102,252,752	$ 54,509,684	$ 8,555,342
SNCP	$ 704,785,477	$ 441,503,160	$ 145,118,191	$ 2,837,221	$ 80,760,304	$ 4,454,543	$ 93	$ 25,746,139	$ 4,365,826
TCP	$ 38,865,982	$ 10,650,973	$ 4,246,620	$ 251,805	$ 13,257,399	$ 6,967,760	$ 3,271,770	$ 150,166	$ 69,489
Total	**$ 3,719,121,107**	**$ 1,366,162,370**	**$ 440,528,777**	**$ 418,903,855**	**$ 669,233,153**	**$ 499,898,481**	**$ 231,921,821**	**$ 78,349,746**	**$ 14,122,903**

Uniform System of Accounts - Detail Accounts

Grouping by Allocator	Adjusted TB	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate
1808	$ 21,423,745.84	$ 21,423,745.84	$ -	$ 21,423,745.84	$ 5,357,419.57	$ 2,354,631.39	$ 1,212,896.73	$ 6,657,014.95	$ 3,889,265.09
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,138,314.47	$ 6,138,314.47	$ -	$ 6,138,314.47	$ 1,430,573.55	$ 768,457.76	$ 411,302.96	$ 1,859,533.97	$ 1,125,752.31
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 6,959,505.99	$ 4,523,678.89	$ 2,435,827.10	$ 6,959,505.99	$ 1,656,272.59	$ 889,695.96	$ 239,647.98	$ 1,064,427.85	$ 460,586.78
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 6,606,422.64	$ 4,294,174.72	$ 2,312,247.92	$ 6,606,422.64	$ 1,319,936.30	$ 709,027.01	$ 254,088.77	$ 1,138,661.77	$ 591,891.57
1850	$ 1,742,721.01	$ 1,219,904.71	$ 522,816.30	$ 1,742,721.01	$ 404,478.79	$ 217,272.90	$ 97,103.12	$ 415,625.33	$ 77,555.13
1855	$ 284,290.62	$ -	$ 284,290.62	$ 284,290.62	$ -	$ -	$ -	$ -	$ -
1860	$ 795,836.01	$ -	$ 795,836.01	$ 795,836.01	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 43,388,815.64	$ 28,202,730.17	$ 15,186,085.47	$ 43,388,815.64	$ 8,969,039.34	$ 4,812,994.88	$ 1,785,063.47	$ 7,901,128.15	$ 3,317,999.31
1830 & 1835	$ 5,141,671.28	$ 3,342,086.33	$ 1,799,584.95	$ 5,141,671.28	$ 1,223,651.39	$ 657,305.88	$ 177,051.52	$ 786,397.50	$ 340,280.74
1840 & 1845	$ 2,720,633.23	$ 1,768,411.60	$ 952,221.63	$ 2,720,633.23	$ 543,571.43	$ 291,988.96	$ 104,637.92	$ 468,919.60	$ 243,750.66
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,000,000.00	$ -	$ 7,000,000.00	$ 7,000,000.00	$ -	$ -	$ -	$ -	$ -
Break Out	$ (1,991,067,124.64)	$ -	$ -	$ -	$ (320,839,847.28)	$ (171,908,029.51)	$ (63,228,598.03)	$ (280,070,825.42)	$ (114,625,775.34)
CCA	$ 4,652,873.62	$ -	$ 4,652,873.62	$ 4,652,873.62	$ -	$ -	$ -	$ -	$ -
CDMPP	$ 15,443,113.67	$ -	$ 15,443,113.67	$ 15,443,113.67	$ -	$ -	$ -	$ -	$ -
CEN	$ 260,301,625.56	$ -	$ 12,765,713.86	$ 12,765,713.86	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ 1,675,016,977.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ (510,276,034.90)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ 316,671,668.57	$ -	$ 316,671,668.57	$ 316,671,668.57	$ -	$ -	$ -	$ -	$ -
CWMC	$ 202,597,599.02	$ -	$ 202,597,599.02	$ 202,597,599.02	$ -	$ -	$ -	$ -	$ -
CWMR	$ 2,970,309.97	$ -	$ 2,970,309.97	$ 2,970,309.97	$ -	$ -	$ -	$ -	$ -
CWNB	$ 19,241,830.10	$ -	$ 29,418,236.10	$ 29,418,236.10	$ -	$ -	$ -	$ -	$ -
DCP	$ 48,867,458.21	$ 48,867,458.21	$ -	$ 48,867,458.21	$ 12,220,247.51	$ 5,370,902.54	$ 2,766,611.43	$ 15,184,618.16	$ 8,871,394.42
LPHA	$ (5,000,000.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ 613,420,550.52	$ 429,394,385.36	$ 184,026,165.16	$ 613,420,550.52	$ 142,372,532.31	$ 76,477,910.91	$ 34,179,337.95	$ 146,296,002.09	$ 27,298,636.94
NFA	$ 40,072,713.95	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 520,805,891.28	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 35,912,761.76	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ 1,472,882,880.85	$ 1,008,913,200.33	$ 463,969,680.52	################	$ 235,133,691.93	$ 126,306,200.02	$ 67,603,083.38	$ 305,639,012.22	$ 185,032,286.93
SNCP	$ 627,631,071.78	$ 407,960,196.65	$ 219,670,875.12	$ 627,631,071.78	$ 210,539,996.94	$ 113,095,264.00	$ 15,163,285.20	$ 64,902,603.05	$ 4,036,912.77
TCP	$ 15,115,982.28	$ 15,115,982.28	$ -	$ 15,115,982.28	$ 3,780,042.01	$ 1,661,360.56	$ 855,785.24	$ 4,696,999.34	$ 2,744,154.20
Total	**$ 3,467,464,106**	**$ 1,981,164,270**	**$ 1,483,475,146**	**$ 3,464,639,415**	**$ 304,111,606**	**$ 161,704,983**	**$ 61,621,298**	**$ 276,940,119**	**$ 123,404,692**

Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS
$ 1,831,312.18	$ 82,756.29	$ 38,449.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 541,184.56	$ -	$ 1,509.36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 211,300.24	$ -	$ 1,747.49	$ 204,220.32	$ 4,204.10	$ 18,428.23	$ 867.35	$ 79.23	$ 270,970.62	$ 54,068.01	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 279,176.66	$ -	$ 1,392.63	$ 193,386.57	$ 4,943.85	$ 21,788.44	$ 1,131.27	$ 104.32	$ 256,595.81	$ 51,199.74	$ -	$ -
$ 7,442.69	$ -	$ 426.75	$ 43,742.23	$ 1,165.03	$ 4,882.52	$ 84.08	$ 1.96	$ 58,039.56	$ 11,580.90	$ -	$ -
$ -	$ -	$ -	$ 42,980.50	$ 1,717.12	$ 7,196.25	$ 41.31	$ 3.07	$ 28,514.43	$ 5,689.62	$ -	$ -
$ -	$ -	$ -	$ 66,147.44	$ 18,733.36	$ 147,387.32	$ 23,274.48	$ 2,553.12	$ -	$ -	$ -	$ -
$ 1,405,963.72	$ 772.27	$ 9,769.03	$ 1,544,672.74	$ 55,573.03	$ 253,979.98	$ 36,841.58	$ 16,688.37	$ 1,625,847.30	$ 324,638.80	$ -	$ -
$ 156,108.26	$ -	$ 1,291.04	$ 150,877.63	$ 3,105.98	$ 13,614.75	$ 640.79	$ 58.53	$ 200,192.63	$ 39,945.36	$ -	$ -
$ 114,969.53	$ -	$ 573.51	$ 79,639.76	$ 2,035.96	$ 8,972.84	$ 465.88	$ 42.96	$ 105,670.36	$ 21,084.89	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 1,881,934.00	$ 801,603.00	$ 131,541.00	$ 251,595.00	$ -	$ -	$ -	$ -	$ -
$ (47,921,188.31)	$ (69,080.51)	$ (365,886.23)	$ (68,610,409.88)	$ (3,771,355.88)	$ (22,773,500.93)	$ (2,586,099.97)	$ (307,208.49)	$ (66,784,387.69)	$ (13,326,166.28)	$ -	$ -
$ -	$ -	$ -	$ 387,942.97	$ 12,374.25	$ 54,777.08	$ 3,060.24	$ 284.00	$ 514,743.80	$ 102,709.20	$ -	$ -
$ -	$ -	$ -	$ 2,559,643.57	$ 657,895.25	$ 2,738,015.75	$ 1,142,566.98	$ 491,981.59	$ 334,371.44	$ 71,170.39	$ -	$ -
$ -	$ -	$ -	$ 1,275,824.74	$ 675,995.26	$ 4,203,726.67	$ 2,519,862.32	$ 1,283,004.65	$ 54,583.03	$ 28,707.72	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (69,517,531.67)	$ (22,458,325.43)
$ -	$ -	$ -	$ 47,876,036.84	$ 1,912,697.75	$ 8,015,908.65	$ 46,010.55	$ 3,424.72	$ 31,762,263.02	$ 6,337,670.31	$ -	$ -
$ -	$ -	$ -	$ 16,839,289.25	$ 4,768,988.93	$ 37,520,691.00	$ 5,925,031.09	$ 649,953.71	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 821,156.70	$ 26,702.96	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 7,457,839.13	$ 832,591.85	$ 3,685,632.59	$ 205,905.62	$ 40,947.14	$ 947.08	$ 3,342.62	$ (2,579,828.33)	$ (288,011.58)
$ 4,177,214.03	$ 188,766.69	$ 87,703.44	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,101,152.00)	$ (734,944.00)
$ 2,619,752.00	$ -	$ 150,213.17	$ 15,396,831.42	$ 410,079.68	$ 1,718,599.43	$ 29,593.79	$ 690.09	$ 20,429,352.19	$ 4,076,362.53	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,481,916.58)	$ (2,978,916.86)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 88,950,843.05	$ -	$ 248,082.80	$ 38,684,432.47	$ 1,233,920.93	$ 5,462,195.17	$ 305,157.03	$ 28,319.50	$ 51,328,606.12	$ 10,241,832.67	$ -	$ -
$ -	$ -	$ 222,134.70	$ 18,531,899.36	$ 148,073.75	$ 620,561.02	$ 3,561.96	$ 88.38	$ 24,589,130.62	$ 4,906,382.24	$ -	$ -
$ 1,292,121.50	$ 58,390.47	$ 27,128.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 53,666,200	**$ 261,605**	**$ 424,536**	**$ 85,428,088**	**$ 7,801,046**	**$ 41,854,398**	**$ 7,909,591**	**$ 2,211,017**	**$ 64,775,440**	**$ 12,950,219**	**-$ 83,680,429**	**-$ 26,460,198**

GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ (41,226,596.64)	$ (11,720,603.78)	$ (53,844,504.92)	$ (21,574,846.95)	$ (9,035,699.07)	$ (11,276,281.08)	$ (2,316,186.51)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ 24,739,113.13	$ 13,108,009.89	$ 81,513,131.63	$ 48,861,851.68	$ 24,878,336.45	$ 1,058,402.29	$ 556,662.32
$ -	$ -	$ -	$ -	$ -	$ 168,898,974.28	$ 89,491,058.71	$ 556,506,785.39	$ 333,589,833.50	$ 154,888,269.98	$ 7,225,928.42	$ 3,800,447.25
$(129,952,515.25)	$ (61,290,348.84)	$ (23,987,572.17)	$ (1,884,919.68)	$ (1,308,526.74)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (1,274,940.26)	$ (71,227.22)	$ (14,164.50)	$ (327.61)	$ (1,156.29)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (192,582.00)	$ (197,409.00)	$ (33,211.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (13,786,925.34)	$ (5,702,626.13)	$ (2,429,527.56)	$ (2,912,484.03)	$ (598,017.00)	$ 15,988,512.71	$ 4,543,868.46	$ 21,029,782.99	$ 8,698,457.92	$ 3,705,861.61	$ 4,442,535.64	$ 912,180.73
$ -	$ -	$ -	$ -	$ -	$ 72,481,192.03	$ 20,606,196.07	$ 94,664,954.63	$ 37,931,111.28	$ 15,885,818.68	$ 19,825,024.64	$ 4,072,127.53
$ -	$ -	$ -	$ -	$ -	$ 5,952,418.12	$ 1,529,926.92	$ 6,367,220.33	$ 2,657,024.78	$ 1,144,096.84	$ 777,576.47	$ 165,505.83
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-$ 145,206,963	**-$ 67,261,611**	**-$ 26,464,475**	**-$ 4,797,731**	**-$ 1,907,700**	**$ 246,833,614**	**$ 117,558,456**	**$ 706,237,370**	**$ 410,163,432**	**$ 191,466,685**	**$ 22,053,186**	**$ 7,190,737**

2009 COST ALLOCATION STUDY

Toronto Hydro-Electric System Limited

EB-2007-0680

Sheet O5 Details of Allocators by Class and Account Worksheet

Uniform System of Accounts - Detail

Grouping by Allocator	Adjusted TB	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate
1808	$ 21,954,294.58	$ 21,954,294.58	$ -	$ 21,954,294.58	$ 5,856,984.44	$ 2,303,404.13	$ 620,373.69	$ 7,227,288.34	$ 3,942,493.12
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,574,792.89	$ 6,574,792.89	$ -	$ 6,574,792.89	$ 1,604,900.63	$ 776,924.46	$ 257,143.67	$ 2,135,145.65	$ 1,213,459.67
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 7,604,333.43	$ 4,942,816.73	$ 2,661,516.70	$ 7,604,333.43	$ 1,886,689.52	$ 913,337.07	$ 152,553.52	$ 1,246,262.70	$ 506,295.97
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,171,837.46	$ 4,661,694.35	$ 2,510,143.11	$ 7,171,837.46	$ 1,496,166.45	$ 724,286.78	$ 160,850.76	$ 1,324,830.03	$ 646,544.37
1850	$ 1,905,325.90	$ 1,333,728.13	$ 571,597.77	$ 1,905,325.90	$ 462,986.15	$ 224,129.31	$ 62,023.38	$ 489,715.59	$ 85,294.09
1855	$ 296,396.81	$ -	$ 296,396.81	$ 296,396.81	$ -	$ -	$ -	$ -	$ -
1860	$ 852,361.86	$ -	$ 852,361.86	$ 852,361.86	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 46,326,696.01	$ 30,112,352.41	$ 16,214,343.60	$ 46,326,696.01	$ 9,989,747.82	$ 4,828,219.41	$ 1,111,030.62	$ 9,065,946.49	$ 3,573,120.00
1830 & 1835	$ 5,284,131.82	$ 3,434,685.68	$ 1,849,446.14	$ 5,284,131.82	$ 1,311,030.91	$ 634,663.58	$ 106,007.05	$ 866,008.37	$ 351,817.11
1840 & 1845	$ 3,485,403.22	$ 2,265,512.09	$ 1,219,891.13	$ 3,485,403.22	$ 727,113.99	$ 351,992.29	$ 78,171.01	$ 643,847.11	$ 314,210.67
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000.00	$ -	$ 7,500,000.00	$ 7,500,000.00	$ -	$ -	$ -	$ -	$ -
Break Out	$ (2,161,750,785.18)	$ -	$ -	$ -	$ (361,309,463.91)	$ (174,446,316.96)	$ (39,692,515.03)	$ (324,124,239.34)	$ (123,917,064.84)
CCA	$ 4,739,803.42	$ -	$ 4,739,803.42	$ 4,739,803.42	$ -	$ -	$ -	$ -	$ -
CDMPP	$ 15,880,933.67	$ -	$ 15,880,933.67	$ 15,880,933.67	$ -	$ -	$ -	$ -	$ -
CEN	$ 270,082,798.25	$ -	$ 21,265,713.73	$ 21,265,713.73	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ 1,674,844,259.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ (545,873,065.82)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ 324,780,991.73	$ -	$ 324,780,991.73	$ 324,780,991.73	$ -	$ -	$ -	$ -	$ -
CWMC	$ 288,651,558.31	$ -	$ 288,651,558.31	$ 288,651,558.31	$ -	$ -	$ -	$ -	$ -
CWMR	$ 2,621,396.90	$ -	$ 2,621,396.90	$ 2,621,396.90	$ -	$ -	$ -	$ -	$ -
CWNB	$ 19,803,717.00	$ -	$ 30,198,298.00	$ 30,198,298.00	$ -	$ -	$ -	$ -	$ -
DCP	$ 52,119,288.41	$ 52,119,288.41	$ -	$ 52,119,288.41	$ 13,904,425.86	$ 5,468,259.70	$ 1,472,761.30	$ 17,157,514.39	$ 9,359,441.51
LPHA	$ (5,000,000.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ 657,630,797.38	$ 460,341,558.16	$ 197,289,239.21	$ 657,630,797.38	$ 159,801,506.76	$ 77,359,119.34	$ 21,407,616.01	$ 169,027,281.09	$ 29,439,592.36
NFA	$ 34,739,624.73	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 563,473,629.65	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 37,049,047.49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ 1,570,461,558.72	$ 1,075,748,148.93	$ 494,713,409.79	################	$ 262,589,090.31	$ 127,118,080.35	$ 42,073,085.64	$ 349,346,210.47	$ 198,542,678.72
SNCP	$ 664,779,156.86	$ 432,106,451.96	$ 232,672,704.90	$ 664,779,156.86	$ 231,932,946.97	$ 112,277,592.92	$ 9,321,185.21	$ 73,596,919.48	$ 4,272,807.91
TCP	$ 23,115,981.94	$ 23,115,981.94	$ -	$ 23,115,981.94	$ 6,166,900.33	$ 2,425,286.23	$ 653,200.08	$ 7,609,712.35	$ 4,151,105.81
Total	**$ 3,601,106,267**	**$ 2,118,711,306**	**$ 1,646,489,747**	**$ 3,765,201,053**	**$ 336,421,026**	**$ 160,958,979**	**$ 37,783,487**	**$ 315,612,443**	**$ 132,481,796**

Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS
$ 1,880,072.31	$ 84,468.43	$ 39,210.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 582,340.44	$ -	$ 4,878.37	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 231,943.04	$ -	$ 5,734.91	$ 216,918.58	$ 2,230.12	$ 21,871.70	$ 936.14	$ 84.24	$ 288,060.36	$ 40,764.54	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 304,468.11	$ -	$ 4,547.85	$ 204,094.74	$ 2,605.30	$ 25,678.96	$ 1,213.11	$ 110.19	$ 271,030.74	$ 38,354.62	$ -	$ -
$ 8,172.29	$ -	$ 1,407.32	$ 46,492.32	$ 619.02	$ 5,825.53	$ 90.79	$ 2.09	$ 61,740.19	$ 8,737.09	$ -	$ -
$ -	$ -	$ -	$ 43,678.38	$ 872.34	$ 8,209.41	$ 42.65	$ 3.13	$ 29,001.69	$ 4,104.14	$ -	$ -
$ -	$ -	$ -	$ 83,490.92	$ 9,240.18	$ 162,462.64	$ 23,402.32	$ 2,528.83	$ -	$ -	$ -	$ -
$ 1,512,376.38	$ 1,233.54	$ 30,678.15	$ 1,597,716.33	$ 31,019.45	$ 325,650.14	$ 58,777.88	$ 27,768.36	$ 1,681,385.70	$ 238,386.78	$ -	$ -
$ 161,173.57	$ -	$ 3,985.10	$ 150,733.31	$ 1,549.68	$ 15,198.30	$ 650.51	$ 58.54	$ 200,168.62	$ 28,326.64	$ -	$ -
$ 147,966.84	$ -	$ 2,210.19	$ 99,186.92	$ 1,266.13	$ 12,479.58	$ 589.55	$ 53.55	$ 131,716.79	$ 18,639.76	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 2,016,358.00	$ 858,861.00	$ 140,936.00	$ 269,566.00	$ -	$ -	$ -	$ -	$ -
$ (51,647,643.75)	$ (73,332.93)	$ (1,116,846.07)	$ (74,587,817.57)	$ (2,079,020.32)	$ (28,014,977.31)	$ (3,057,684.66)	$ (411,271.40)	$ (70,117,780.04)	$ (9,924,551.35)	$ -	$ -
$ -	$ -	$ -	$ 384,221.70	$ 6,118.55	$ 60,553.50	$ 3,079.38	$ 281.51	$ 510,233.11	$ 72,205.08	$ -	$ -
$ -	$ -	$ -	$ 2,525,407.09	$ 409,347.77	$ 3,023,210.43	$ 1,175,783.92	$ 507,346.07	$ 335,971.92	$ 56,220.35	$ -	$ -
$ -	$ -	$ -	$ 2,123,987.09	$ 546,643.83	$ 7,477,619.16	$ 4,203,235.50	$ 2,142,593.59	$ 91,117.75	$ 47,952.44	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (74,315,256.29)	$ (11,229,728.48)
$ -	$ -	$ -	$ 47,861,202.70	$ 955,874.66	$ 8,995,571.89	$ 46,731.41	$ 3,426.53	$ 31,779,009.40	$ 4,497,171.48	$ -	$ -
$ -	$ -	$ -	$ 28,274,124.33	$ 3,129,178.04	$ 55,017,822.67	$ 7,925,175.36	$ 856,386.49	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 707,450.79	$ 11,765.76	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 7,454,626.33	$ 415,489.69	$ 4,111,982.49	$ 209,110.31	$ 40,963.77	$ 947.46	$ 3,343.98	$ (2,565,963.06)	$ (143,016.05)
$ 4,463,273.95	$ 200,527.25	$ 93,084.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,101,152.00)	$ (734,943.00)
$ 2,820,698.86	$ -	$ 485,743.75	$ 16,047,007.66	$ 213,658.48	$ 2,010,703.21	$ 31,336.41	$ 719.83	$ 21,309,870.15	$ 3,015,642.78	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,837,528.66)	$ (1,837,593.18)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 95,280,819.42	$ -	$ 798,184.02	$ 40,102,850.70	$ 638,618.62	$ 6,320,225.58	$ 321,408.06	$ 29,382.45	$ 53,255,196.17	$ 7,536,350.38	$ -	$ -
$ -	$ -	$ 704,999.48	$ 19,078,369.73	$ 76,205.90	$ 717,160.61	$ 3,725.60	$ 91.06	$ 25,335,413.94	$ 3,585,313.17	$ -	$ -
$ 1,979,554.27	$ 88,937.98	$ 41,284.88	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 57,725,216	**$ 301,834**	**$ 1,099,103**	**$ 94,430,100**	**$ 5,232,144**	**$ 60,438,184**	**$ 11,217,170**	**$ 3,200,529**	**$ 65,163,084**	**$ 9,266,962**	**-$ 88,819,900**	**-$ 13,945,281**

GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ (42,697,074.05)	$ (7,281,482.48)	$ (63,874,624.42)	$ (23,656,012.49)	$ (9,843,067.07)	$ (11,379,541.14)	$ (1,802,719.89)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ 24,851,471.37	$ 6,395,944.43	$ 87,491,039.38	$ 49,179,482.79	$ 25,069,174.65	$ 1,066,112.92	$ 561,062.17
$ -	$ -	$ -	$ -	$ -	$ 168,775,205.21	$ 43,437,139.74	$ 594,182,851.70	$ 333,995,407.27	$ 155,292,404.93	$ 7,240,353.04	$ 3,810,373.32
$(141,189,574.52)	$ (61,791,540.76)	$ (24,911,702.17)	$ (4,316,459.27)	$ (1,814,432.91)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (1,415,388.88)	$ (71,978.03)	$ (14,100.17)	$ (326.13)	$ (1,151.03)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (192,583.00)	$ (197,409.00)	$ (33,211.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (16,332,619.05)	$ (6,250,128.56)	$ (2,649,179.49)	$ (2,914,024.97)	$ (460,306.97)	$ 15,355,811.70	$ 2,603,705.68	$ 23,141,864.77	$ 8,855,874.83	$ 3,753,651.10	$ 4,128,913.54	$ 652,213.93
$ -	$ -	$ -	$ -	$ -	$ 74,253,188.05	$ 12,663,005.60	$ 111,082,424.35	$ 41,139,454.70	$ 17,117,779.77	$ 19,789,815.27	$ 3,135,055.55
$ -	$ -	$ -	$ -	$ -	$ 5,891,588.55	$ 954,978.18	$ 7,052,927.05	$ 2,743,017.21	$ 1,183,600.98	$ 783,797.72	$ 131,157.94
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-$ 159,130,165	**-$ 68,311,056**	**-$ 27,608,193**	**-$ 7,230,810**	**-$ 2,275,891**	**$ 246,430,191**	**$ 58,773,291**	**$ 759,076,483**	**$ 412,257,224**	**$ 192,573,544**	**$ 21,629,451**	**$ 6,487,143**

Uniform System of Accounts - Detail

Grouping by Allocator	Adjusted TB	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate
1808	$ 22,661,092.22	$ 22,661,092.22	$ -	$ 22,661,092.22	$ 6,210,126.89	$ 2,476,022.27	$ 146,816.92	$ 7,729,822.75	$ 4,062,602.99
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,971,478.15	$ 6,971,478.15	$ -	$ 6,971,478.15	$ 1,727,483.82	$ 888,813.46	$ 79,182.85	$ 2,359,438.14	$ 1,291,159.62
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 8,306,950.10	$ 5,399,517.57	$ 2,907,432.54	$ 8,306,950.10	$ 2,063,313.65	$ 1,061,602.38	$ 48,108.57	$ 1,411,385.72	$ 554,478.09
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,789,580.20	$ 5,063,227.13	$ 2,726,353.07	$ 7,789,580.20	$ 1,634,500.39	$ 840,972.24	$ 50,585.49	$ 1,495,727.81	$ 704,407.10
1850	$ 2,082,925.43	$ 1,458,047.80	$ 624,877.63	$ 2,082,925.43	$ 512,271.81	$ 263,570.68	$ 19,688.16	$ 558,766.08	$ 93,288.97
1855	$ 308,503.33	$ -	$ 308,503.33	$ 308,503.33	$ -	$ -	$ -	$ -	$ -
1860	$ 897,312.36	$ -	$ 897,312.36	$ 897,312.36	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 46,489,585.93	$ 30,218,230.85	$ 16,271,355.08	$ 46,489,585.93	$ 10,073,655.98	$ 5,166,437.62	$ 321,798.59	$ 9,476,795.58	$ 3,613,432.15
1830 & 1835	$ 5,547,164.14	$ 3,605,656.69	$ 1,941,507.45	$ 5,547,164.14	$ 1,377,826.92	$ 708,910.32	$ 32,125.65	$ 942,486.49	$ 370,265.97
1840 & 1845	$ 3,756,727.01	$ 2,441,872.56	$ 1,314,854.45	$ 3,756,727.01	$ 788,280.19	$ 405,580.67	$ 24,396.16	$ 721,353.51	$ 339,718.59
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000.00	$ -	$ 7,500,000.00	$ 7,500,000.00	$ -	$ -	$ -	$ -	$ -
Break Out	$ (2,333,819,965.46)	$ -	$ -	$ -	$ (390,133,690.66)	$ (200,079,015.25)	$ (12,297,859.33)	$(361,645,943.60)	$(133,108,412.63)
CCA	$ 5,770,991.27	$ -	$ 5,770,991.27	$ 5,770,991.27	$ -	$ -	$ -	$ -	$ -
CDMPP	$ 16,249,460.57	$ -	$ 16,249,460.67	$ 16,249,460.67	$ -	$ -	$ -	$ -	$ -
CEN	$ 276,592,689.59	$ -	$ 27,265,713.94	$ 27,265,713.94	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ 1,676,227,553.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ (574,181,853.65)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ 333,287,980.49	$ -	$ 333,287,980.49	$ 333,287,980.49	$ -	$ -	$ -	$ -	$ -
CWMC	$ 331,074,774.02	$ -	$ 331,074,774.02	$ 331,074,774.02	$ -	$ -	$ -	$ -	$ -
CWMR	$ 2,275,089.17	$ -	$ 2,275,089.17	$ 2,275,089.17	$ -	$ -	$ -	$ -	$ -
CWNB	$ 20,255,542.50	$ -	$ 30,937,298.50	$ 30,937,298.50	$ -	$ -	$ -	$ -	$ -
DCP	$ 53,948,245.70	$ 53,948,245.70	$ -	$ 53,948,245.70	$ 14,784,170.52	$ 5,894,555.14	$ 349,520.45	$ 18,402,042.26	$ 9,671,656.69
LPHA	$ (5,000,000.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ 700,832,948.14	$ 490,583,063.70	$ 210,249,884.44	$ 700,832,948.14	$ 172,361,889.62	$ 88,682,490.17	$ 6,624,391.26	$ 188,005,616.84	$ 31,388,537.94
NFA	$ 30,725,227.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 614,357,593.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 37,663,940.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ 1,676,898,111.70	$ 1,148,879,288.91	$ 528,018,822.79	$ 1,676,898,111.70	$ 284,684,300.82	$ 146,473,868.24	$ 13,049,103.54	$ 388,828,531.09	$ 212,779,343.63
SNCP	$ 704,785,477.43	$ 458,110,560.33	$ 246,674,917.10	$ 704,785,477.43	$ 244,398,868.41	$ 125,746,476.17	$ 2,817,897.39	$ 79,974,221.87	$ 4,450,707.27
TCP	$ 38,865,981.76	$ 38,865,981.76	$ -	$ 38,865,981.76	$ 10,650,972.88	$ 4,246,619.51	$ 251,805.33	$ 13,257,399.38	$ 6,967,760.08
Total	**$ 3,719,121,106**	**$ 2,268,206,263**	**$ 1,766,297,128**	**$ 4,034,503,392**	**$ 361,133,971**	**$ 182,776,904**	**$ 11,517,561**	**$ 351,517,644**	**$ 143,178,946**

Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS
$ 1,907,629.20	$ 87,555.31	$ 40,515.89	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 620,294.20	$ -	$ 5,106.06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 254,530.46	$ -	$ 6,098.70	$ 227,005.23	$ 581.58	$ 24,621.43	$ 993.50	$ 88.25	$ 301,703.20	$ 42,695.20	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 332,202.88	$ -	$ 4,831.22	$ 212,382.19	$ 675.36	$ 28,730.49	$ 1,280.07	$ 114.78	$ 282,268.33	$ 39,944.89	$ -	$ -
$ 8,947.94	$ -	$ 1,514.16	$ 48,694.54	$ 161.92	$ 6,586.56	$ 96.41	$ 2.19	$ 64,717.89	$ 9,158.48	$ -	$ -
$ -	$ -	$ -	$ 43,728.71	$ 218.10	$ 8,872.31	$ 43.29	$ 3.13	$ 29,059.00	$ 4,112.25	$ -	$ -
$ -	$ -	$ -	$ 86,278.73	$ 2,305.74	$ 175,321.33	$ 23,775.44	$ 2,536.03	$ -	$ -	$ -	$ -
$ 1,533,804.09	$ 2,020.07	$ 30,286.79	$ 1,532,615.89	$ 7,660.53	$ 356,474.09	$ 70,243.99	$ 33,674.80	$ 1,614,944.73	$ 229,081.41	$ -	$ -
$ 169,968.79	$ -	$ 4,072.55	$ 151,588.16	$ 388.36	$ 16,441.54	$ 663.43	$ 58.93	$ 201,469.51	$ 28,510.74	$ -	$ -
$ 160,213.45	$ -	$ 2,329.98	$ 102,426.82	$ 325.71	$ 13,856.02	$ 617.35	$ 55.35	$ 136,131.22	$ 19,264.46	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 2,016,358.00	$ 858,861.00	$ 140,936.00	$ 269,566.00	$ -	$ -	$ -	$ -	$ -
$ (55,516,305.78)	$ (79,130.47)	$ (1,173,177.06)	$ (77,809,768.77)	$ (575,580.46)	$ (32,448,276.07)	$ (3,535,510.98)	$ (543,268.34)	$ (72,240,782.15)	$ (10,226,792.39)	$ -	$ -
$ -	$ -	$ -	$ 448,260.66	$ 1,777.67	$ 75,923.17	$ 3,642.54	$ 328.70	$ 595,764.58	$ 84,308.97	$ -	$ -
$ -	$ -	$ -	$ 2,588,028.31	$ 174,738.15	$ 3,211,906.37	$ 1,200,876.72	$ 515,867.47	$ 336,085.10	$ 56,256.20	$ -	$ -
$ -	$ -	$ -	$ 2,722,472.23	$ 161,380.25	$ 9,943,311.44	$ 5,392,241.74	$ 2,750,320.82	$ 116,934.38	$ 61,555.42	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (76,828,015.73)	$ (2,666,281.65)
$ -	$ -	$ -	$ 47,241,802.14	$ 235,627.07	$ 9,585,094.68	$ 46,766.43	$ 3,384.97	$ 31,393,556.00	$ 4,442,624.47	$ -	$ -
$ -	$ -	$ -	$ 31,833,633.32	$ 850,733.63	$ 64,687,027.43	$ 8,772,249.61	$ 935,700.51	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 594,443.43	$ 2,815.47	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ 7,392,577.10	$ 102,608.61	$ 4,382,355.73	$ 210,250.85	$ 40,656.24	$ 940.35	$ 3,318.88	$ (2,552,443.45)	$ (35,427.79)
$ 4,541,407.27	$ 208,439.01	$ 96,454.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,101,152.24)	$ (734,943.95)
$ 3,010,674.09	$ -	$ 509,463.78	$ 16,384,042.38	$ 54,478.93	$ 2,216,153.07	$ 32,438.35	$ 735.56	$ 21,775,348.47	$ 3,081,514.43	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,228,935.60)	$ (573,423.23)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 102,222,677.50	$ -	$ 841,464.09	$ 41,013,762.74	$ 162,648.30	$ 6,946,616.68	$ 333,275.57	$ 30,074.59	$ 54,509,684.17	$ 7,713,877.87	$ -	$ -
$ -	$ -	$ 722,389.22	$ 19,371,714.82	$ 19,323.99	$ 786,082.29	$ 3,835.36	$ 92.53	$ 25,746,139.49	$ 3,643,436.55	$ -	$ -
$ 3,271,770.01	$ 150,165.90	$ 69,488.69	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 62,517,814	**$ 369,050**	**$ 1,160,838**	**$ 96,202,047**	**$ 2,061,730**	**$ 70,158,035**	**$ 12,827,346**	**$ 3,770,427**	**$ 64,863,964**	**$ 9,232,868**	**-$ 92,710,547**	**-$ 4,010,077**

GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ (48,241,499.69)	$ (2,276,132.39)	$ (73,693,364.80)	$ (26,406,505.77)	$ (11,012,420.22)	$ (11,660,847.30)	$ (1,858,906.08)
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ (0.02)	$ (0.00)	$ (0.02)	$ (0.01)	$ (0.00)	$ (0.00)	$ (0.00)
$ -	$ -	$ -	$ -	$ -	$ 24,895,213.43	$ 1,475,715.96	$ 90,925,026.77	$ 49,308,495.21	$ 25,149,870.41	$ 1,069,287.77	$ 562,883.74
$ -	$ -	$ -	$ -	$ -	$ 171,897,858.14	$ 405,030,270.90	$ 240,566,019.17	$ 333,232,292.78	$ 155,917,626.27	$ 7,149,431.75	$ 3,568,135.21
$(149,686,141.45)	$ (62,746,059.58)	$ (25,602,538.34)	$ (5,373,463.75)	$ (2,043,968.79)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (1,513,100.91)	$ (72,593.55)	$ (14,037.43)	$ (324.68)	$ (1,145.91)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (192,581.99)	$ (197,408.99)	$ (33,211.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ (18,893,183.02)	$ (7,006,590.36)	$ (2,978,294.74)	$ (2,979,374.92)	$ (473,792.94)	$ 16,332,267.44	$ 765,831.29	$ 25,232,655.40	$ 9,357,601.62	$ 3,977,640.23	$ 3,979,082.86	$ 632,770.77
$ -	$ -	$ -	$ -	$ -	$ 83,377,852.52	$ 3,933,937.21	$ 127,367,402.37	$ 45,639,496.24	$ 19,033,238.08	$ 20,153,942.41	$ 3,212,827.09
$ -	$ -	$ -	$ -	$ -	$ 5,998,681.89	$ 405,018.20	$ 7,444,742.59	$ 2,783,461.61	$ 1,195,707.50	$ 778,997.50	$ 130,393.87
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
-$ 170,285,007	**-$ 70,022,652**	**-$ 28,628,082**	**-$ 8,353,163**	**-$ 2,518,908**	**$ 254,260,374**	**$ 409,334,641**	**$ 417,842,481**	**$ 413,914,842**	**$ 194,261,662**	**$ 21,469,895**	**$ 6,248,105**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O6 Composite Allocator Detail Worksheet

Ontario

Details:
Output Sheet Details How Various Composite Allocators are Derived

Demand Allocators can be found in columns C to AG
Customer Allocators can be found in columns AJ to BN

Composite allocators

Rate Base

		Demand Allocators									Customer Allocators								
			1	2	3	4	5	6	7	9		1	2	3	4	5	6	7	
		Demand Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,443,114	$7,447,469	$2,559,644	$657,895	$2,738,016	$1,142,567	$491,982	$334,371	$15,443,114
1805-1	Land Station >50 kV		$113,635	$49,944	$25,727	$141,201	$82,495	$38,844	$1,755	$816	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$421,648	$185,318	$95,459	$523,930	$306,099	$144,131	$6,513	$3,026	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$2,140,539	$535,283	$235,261	$121,186	$665,131	$388,593	$182,974	$8,269	$3,842	$0	$0	$0	$0	$0	$0	$0	$0	$2,140,539
1806-1	Land Rights Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$357,654	$157,192	$80,971	$444,413	$259,642	$122,256	$5,525	$2,567	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$1,430,219	$357,654	$157,192	$80,971	$444,413	$259,642	$122,256	$5,525	$2,567	$0	$0	$0	$0	$0	$0	$0	$0	$1,430,219
1808-1	Buildings and Fixtures > 50 kV		$370,192	$162,703	$83,810	$459,993	$268,744	$126,542	$5,718	$2,657	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$11,440,946	$5,028,393	$2,590,181	$14,216,275	$8,305,654	$3,910,828	$176,729	$82,110	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$47,231,474	$11,811,138	$5,191,096	$2,673,991	$14,676,268	$8,574,398	$4,037,369	$182,447	$84,767	$0	$0	$0	$0	$0	$0	$0	$0	$47,231,474
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$13,181,208	$3,296,215	$1,448,714	$746,249	$4,095,806	$2,392,915	$1,126,736	$50,917	$23,657	$0	$0	$0	$0	$0	$0	$0	$0	$13,181,208
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$147,255,222	$34,318,774	$18,434,933	$9,866,961	$44,609,329	$27,006,258	$12,982,758	$0	$36,209	$0	$0	$0	$0	$0	$0	$0	$0	$147,255,222
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,765,714	$2,724,009	$1,275,825	$675,995	$4,203,727	$2,519,862	$1,283,005	$54,583	$12,765,714
1820	Total	$147,255,222	$34,318,774	$18,434,933	$9,866,961	$44,609,329	$27,006,258	$12,982,758	$0	$36,209	$12,765,714	$2,724,009	$1,275,825	$675,995	$4,203,727	$2,519,862	$1,283,005	$54,583	$160,020,936
1815 & 1820	Total	$160,436,430	$37,614,989	$19,883,648	$10,613,210	$48,705,134	$29,399,174	$14,109,494	$50,917	$59,865	$12,765,714	$2,724,009	$1,275,825	$675,995	$4,203,727	$2,519,862	$1,283,005	$54,583	$173,202,144
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$25,522,432	$13,709,824	$7,337,932	$33,175,386	$20,084,208	$9,655,111	$0	$26,928	$58,967,904	$45,332,659	$4,916,571	$156,824	$694,214	$38,784	$3,599	$6,523,573	$58,967,904
1830-5	Poles, Towers and Fixtures - Secondary		$50,158,956	$26,943,766	$3,612,494	$15,462,368	$961,752	$0	$0	$52,921	$52,334,293	$40,708,274	$4,415,032	$35,277	$147,842	$849	$21	$5,858,104	$52,334,293
1830	Total	$206,704,079	$75,681,389	$40,653,590	$10,950,427	$48,637,754	$21,045,960	$9,655,111	$0	$79,849	$111,302,197	$86,040,934	$9,331,603	$192,101	$842,056	$39,632	$3,620	$12,381,677	$318,006,276
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$18,822,359	$10,110,761	$5,411,600	$24,466,282	$14,811,761	$7,120,480	$0	$19,859	$43,487,824	$33,432,064	$3,625,887	$115,655	$511,971	$28,602	$2,654	$4,811,024	$43,487,824
1835-5	Overhead Conductors and Devices - Secondary		$36,991,376	$19,870,568	$2,664,153	$11,403,233	$709,276	$0	$0	$39,029	$38,595,649	$30,021,659	$3,256,011	$26,016	$109,031	$626	$16	$4,320,252	$38,595,649
1835	Total	$152,440,737	$55,813,735	$29,981,330	$8,075,753	$35,869,515	$15,521,037	$7,120,480	$0	$58,887	$82,083,474	$63,453,723	$6,881,898	$141,671	$621,002	$29,228	$2,670	$9,131,276	$234,524,211
1830 & 1835	Total	$359,144,817	$131,495,124	$70,634,919	$19,026,180	$84,507,268	$36,566,998	$16,775,591	$0	$138,737	$193,385,671	$149,494,657	$16,213,501	$333,773	$1,463,058	$68,860	$6,290	$21,512,953	$552,530,487
1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

1840-4	Underground Conduit - Primary		$108,593,628	$58,332,978	$31,221,660	$141,155,650	$85,454,905	$41,080,862	$0	$114,574	$250,898,446	$192,882,791	$20,919,177	$667,261	$2,953,763	$165,018	$15,314	$27,756,701	$250,898,446
1840-5	Underground Conduit - Secondary		$85,635,077	$46,000,388	$6,167,517	$26,398,497	$1,641,975	$0	$0	$90,351	$89,348,972	$69,500,174	$7,537,668	$60,228	$252,407	$1,449	$36	$10,001,388	$89,348,972
1840	Total	$631,888,063	$194,228,705	$104,333,367	$37,389,177	$167,554,147	$87,096,880	$41,080,862	$0	$204,925	$340,247,419	$262,382,965	$28,456,845	$727,488	$3,206,170	$166,467	$15,350	$37,758,088	$972,135,481
1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$47,876,499	$25,717,704	$13,764,930	$62,232,365	$37,675,154	$18,111,632	$0	$50,513	$110,615,506	$85,037,703	$9,222,797	$294,180	$1,302,248	$72,753	$6,752	$12,237,308	$110,615,506
1845-5	Underground Conductors and Devices - Secondary		$37,754,588	$20,280,541	$2,719,120	$11,638,506	$723,910	$0	$0	$39,834	$39,391,961	$30,641,070	$3,323,189	$26,553	$111,281	$639	$16	$4,409,388	$39,391,961
1845	Total	$278,585,295	$85,631,086	$45,998,245	$16,484,051	$73,870,871	$38,399,064	$18,111,632	$0	$90,347	$150,007,467	$115,678,773	$12,545,986	$320,733	$1,413,528	$73,392	$6,768	$16,646,695	$428,592,762
1840 & 1845	Total	$910,473,358	$279,859,791	$150,331,611	$53,873,228	$241,425,018	$125,495,944	$59,192,494	$0	$295,272	$490,254,885	$378,061,738	$41,002,831	$1,048,222	$4,619,698	$239,859	$22,118	$54,404,784	$1,400,728,243
1850	Line Transformers	$429,394,385	$142,372,532	$76,477,911	$34,179,338	$146,296,002	$27,298,637	$2,619,752	$0	$150,213	$184,026,165	$141,964,656	$15,396,831	$410,080	$1,718,599	$29,594	$690	$20,429,352	$613,420,551
1815- 1850	Total	$1,859,448,991	$591,342,436	$317,328,089	$117,691,955	$520,933,423	$218,760,752	$92,697,331	$50,917	$644,087	$880,432,435	$672,245,060	$73,888,988	$2,468,070	$12,005,082	$2,858,175	$1,312,103	$96,401,672	$2,739,881,425
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$316,671,669	$220,717,657	$47,876,037	$1,912,698	$8,015,909	$46,011	$3,425	$31,762,263	$316,671,669
1815- 1855	Total	$1,859,448,991	$591,342,436	$317,328,089	$117,691,955	$520,933,423	$218,760,752	$92,697,331	$50,917	$644,087	$1,197,104,103	$892,962,717	$121,765,025	$4,380,767	$20,020,991	$2,904,186	$1,315,527	$128,163,935	$3,056,553,094
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$196,585,247	$132,831,145	$16,339,561	$4,627,463	$36,407,215	$5,749,198	$630,665	$0	$196,585,247
1815-1860	Total	$1,859,448,991	$591,342,436	$317,328,089	$117,691,955	$520,933,423	$218,760,752	$92,697,331	$50,917	$644,087	$1,393,689,350	$1,025,793,862	$138,104,586	$9,008,230	$56,428,206	$8,653,384	$1,946,193	$128,163,935	$3,253,138,341
1565-1860	Total	$1,910,251,223	$604,046,511	$322,911,638	$120,568,103	$536,719,235	$227,983,385	$97,039,931	$247,157	$735,263	$1,409,132,464	$1,033,241,330	$140,664,229	$9,666,125	$59,166,222	$9,795,951	$2,438,174	$128,498,306	$3,319,383,687

	Total Demand And Customer	$3,319,383,687	$1,637,287,841	$463,575,867	$130,234,229	$595,885,456	$237,779,336	$99,478,105	$128,745,464	$26,397,389
	Accum Depreciation - NFA	($1,816,053,067)	($900,419,584)	($256,995,535)	($71,524,962)	($324,169,153)	($125,390,500)	($51,596,345)	($71,345,472)	($14,611,515)
	Accum Depreciation - NFA ECC	($1,596,178,809)	($792,439,076)	($223,755,340)	($62,053,937)	($282,664,899)	($112,275,617)	($46,916,257)	($63,149,855)	($12,923,828)
NFA	Net Fixed Assets	$1,503,330,620	$736,868,257	$206,580,333	$58,709,267	$271,716,303	$112,388,836	$47,881,760	$57,399,991	$11,785,874
NFA ECC	Net Fixed Assets Excluding Capital Contribution	$1,723,204,878	$844,848,765	$239,820,528	$68,180,292	$313,220,558	$125,503,719	$52,561,848	$65,595,608	$13,473,561

Operating and Maintenance Allocate all the costs to the O and M expenses before using it as a composite allocator.

Acccounts

O&M DC	Total	$70,913,047	$20,904,943	$10,701,375	$4,281,792	$20,291,709	$10,047,082	$4,547,458	$83,529	$55,159	$69,887,109	$49,144,887	$13,374,268	$1,906,277	$5,461,677	$699,741	$80,051	$3,061,522
O&M	Total Demand and Customer	$145,255,728	$70,049,830	$24,075,643	$6,188,069	$25,753,386	$10,746,822	$4,627,509	$3,145,050	$669,419									

Accounts

4705	Power Purchased	$1,509,668,249	$325,017,626	$152,226,170	$80,656,979	$501,571,408	$300,659,627	$139,598,527	$6,512,623	$3,425,287	$1,509,668,249
4708	Charges-WMS	$138,679,579	$29,856,432	$13,983,643	$7,409,228	$46,074,832	$27,618,883	$12,823,655	$598,256	$314,650	$138,679,579
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$139,696,116	$29,809,030	$13,961,441	$7,397,464	$46,001,680	$27,575,033	$14,040,011	$597,306	$314,151	$139,696,116
4716	Charges-CN	$107,839,796	$23,011,375	$10,777,672	$5,710,546	$35,511,451	$21,286,819	$10,838,325	$461,096	$242,512	$107,839,796
4730	Rural Rate Assistance Expense	$26,669,150	$5,741,622	$2,689,162	$1,424,851	$8,860,545	$5,311,324	$2,466,088	$115,049	$60,510	$26,669,150
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power	$1,922,552,889	$413,436,084	$193,638,087	$102,599,069	$638,019,917	$382,451,685	$179,766,606	$8,284,331	$4,357,110	$1,922,552,889

Acccounts

	OM&A Expenses	**$193,919,141**	**$93,619,269**	**$31,789,289**	**$8,218,603**	**$34,430,497**	**$14,347,096**	**$6,170,737**	**$4,408,871**	**$934,779**	**$193,919,141**

Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)	Demand Allocators									Customer Allocators						
	Demand Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50- Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50- Intermediate	Large Use >5MW	Street Light	Total
1808	$ 21,423,746	$ 5,357,420	$ 2,354,631	$ 1,212,897	$ 6,657,015	$ 3,889,265	$ 1,831,312	$ 82,756	$ 38,450	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,138,314	$ 1,430,574	$ 768,458	$ 411,303	$ 1,859,534	$ 1,125,752	$ 541,185	$ -	$ 1,509	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 4,523,679	$ 1,656,273	$ 889,696	$ 239,648	$ 1,064,428	$ 460,587	$ 211,300	$ -	$ 1,747	$ 2,109,842	$ 1,882,989	$ 204,220	$ 4,204	$ 18,428	$ 867	$ 79	$ 270,971	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 4,294,175	$ 1,319,936	$ 709,027	$ 254,089	$ 1,138,662	$ 591,892	$ 279,177	$ -	$ 1,393	$ 2,003,217	$ 1,783,098	$ 193,387	$ 4,944	$ 21,788	$ 1,131	$ 104	$ 256,596	$ -
1850	$ 1,219,905	$ 404,479	$ 217,273	$ 97,103	$ 415,625	$ 77,555	$ 7,443	$ -	$ 427	$ 453,110	$ 403,320	$ 43,742	$ 1,165	$ 4,883	$ 84	$ 2	$ 58,040	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 250,042	$ 198,148	$ 42,981	$ 1,717	$ 7,196	$ 41	$ 3	$ 28,514	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 770,008	$ 537,740	$ 66,147	$ 18,733	$ 147,387	$ 23,274	$ 2,553	$ -	$ -
1815-1855	$ 28,202,730	$ 8,969,039	$ 4,812,995	$ 1,785,063	$ 7,901,128	$ 3,317,999	$ 1,405,964	$ 772	$ 9,769	$ 13,182,069	$ 11,327,844	$ 1,544,673	$ 55,573	$ 253,980	$ 36,842	$ 16,688	$ 1,625,847	$ -
1830 & 1835	$ 3,342,086	$ 1,223,651	$ 657,306	$ 177,052	$ 786,398	$ 340,281	$ 156,108	$ -	$ 1,291	$ 1,558,748	$ 1,391,149	$ 150,878	$ 3,106	$ 13,615	$ 641	$ 59	$ 200,193	$ -

1840 & 1845	$ 1,768,412	$ 543,571	$ 291,989	$ 104,638	$ 468,920	$ 243,751	$ 114,970	$ -	$ 574	$ 824,958	$ 734,309	$ 79,640	$ 2,036	$ 8,973	$ 466	$ 43	$ 105,670	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,748,405	$ 3,933,327	$ 1,881,934	$ 801,603	$ 131,541	$ 251,595	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,032,076	$ 3,576,982	$ 387,943	$ 12,374	$ 54,777	$ 3,060	$ 284	$ 514,744	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,817,230	$ 4,062,500	$ 499,728	$ 141,526	$ 1,113,476	$ 175,833	$ 19,288	$ -	$ -
CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,970,310	$ 2,122,450	$ 821,157	$ 26,703	$ -	$ -	$ -	$ -	$ -
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,167,094	$ 17,191,030	$ 7,457,839	$ 832,592	$ 3,685,633	$ 205,906	$ 40,947	$ 947	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 70,913,047**	**$ 20,904,943**	**$ 10,701,375**	**$ 4,281,792**	**$ 20,291,709**	**$ 10,047,082**	**$ 4,547,458**	**$ 83,529**	**$ 55,159**	**$ 69,887,109**	**$ 49,144,887**	**$ 13,374,268**	**$ 1,906,277**	**$ 5,461,677**	**$ 699,741**	**$ 80,051**	**$ 3,061,522**	**$ -**

Grouping of OM&A (lines 168 - 240)	**Demand Allocators**										**Customer Allocators**							
	Demand Total	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Customer Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Total**
1808	$ 21,423,746	$ 5,357,420	$ 2,354,631	$ 1,212,897	$ 6,657,015	$ 3,889,265	$ 1,831,312	$ 82,756	$ 38,450	$ 21,423,746	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,138,314	$ 1,430,574	$ 768,458	$ 411,303	$ 1,859,534	$ 1,125,752	$ 541,185	$ -	$ 1,509	$ 6,138,314	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 6,959,506	$ 3,539,262	$ 1,093,916	$ 243,852	$ 1,082,856	$ 461,454	$ 211,379	$ 270,971	$ 55,815	$ 6,959,506	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 6,606,423	$ 3,103,034	$ 902,414	$ 259,033	$ 1,160,450	$ 593,023	$ 279,281	$ 256,596	$ 52,592	$ 6,606,423	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ 1,742,721	$ 807,799	$ 261,015	$ 98,268	$ 420,508	$ 77,639	$ 7,445	$ 58,040	$ 12,008	$ 1,742,721	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 284,291	$ 198,148	$ 42,981	$ 1,717	$ 7,196	$ 41	$ 3	$ 28,514	$ 5,690	$ 284,291	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ 795,836	$ 537,740	$ 66,147	$ 18,733	$ 147,387	$ 23,274	$ 2,553	$ -	$ -	$ 795,836	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 43,388,816	$ 20,296,883	$ 6,357,668	$ 1,840,636	$ 8,155,108	$ 3,354,841	$ 1,422,652	$ 1,626,620	$ 334,408	$ 43,388,816	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 5,141,671	$ 2,614,801	$ 808,184	$ 180,158	$ 800,012	$ 340,922	$ 156,167	$ 200,193	$ 41,236	$ 5,141,671	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ 2,720,633	$ 1,277,880	$ 371,629	$ 106,674	$ 477,892	$ 244,217	$ 115,012	$ 105,670	$ 21,658	$ 2,720,633	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,000,000	$ 3,933,327	$ 1,881,934	$ 801,603	$ 131,541	$ 251,595	$ -	$ -	$ -	$ 7,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 4,652,874	$ 3,576,982	$ 387,943	$ 12,374	$ 54,777	$ 3,060	$ 284	$ 514,744	$ 102,709	$ 4,652,874	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ 6,012,352	$ 4,062,500	$ 499,728	$ 141,526	$ 1,113,476	$ 175,833	$ 19,288	$ -	$ -	$ 6,012,352	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ 2,970,310	$ 2,122,450	$ 821,157	$ 26,703	$ -	$ -	$ -	$ -	$ -	$ 2,970,310	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ 29,418,236	$ 17,191,030	$ 7,457,839	$ 832,592	$ 3,685,633	$ 205,906	$ 40,947	$ 947	$ 3,343	$ 29,418,236	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ 7,571,070	$ 3,711,014	$ 1,040,379	$ 295,671	$ 1,368,417	$ 566,012	$ 241,142	$ 289,078	$ 59,356	$ 7,571,070	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 5,179,581	$ 2,539,432	$ 720,849	$ 204,935	$ 941,473	$ 377,237	$ 157,990	$ 197,166	$ 40,499	$ 5,179,581	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 35,912,762	$ 17,318,992	$ 5,952,418	$ 1,529,927	$ 6,367,220	$ 2,657,025	$ 1,144,097	$ 777,576	$ 165,506	$ 35,912,762	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 193,919,141**	**$ 93,619,269**	**$ 31,789,289**	**$ 8,218,603**	**$ 34,430,497**	**$ 14,347,096**	**$ 6,170,737**	**$ 4,408,871**	**$ 934,779**	**$ 193,919,141**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O6 Composite Allocator Detail Worksheet

Ontario

Details:
Output Sheet Details How Various Composite Allocators are Derived

Demand Allocators can be found in columns C to AG
Customer Allocators can be found in columns AJ to BN

Composite allocators

Rate Base

		Demand Allocators									Customer Allocators									
			1	2	3	4	5	6	7	9		1	2	3	4	5	6	7	9	
		Demand Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,880,934	$7,847,646	$2,525,407	$409,348	$3,023,210	$1,175,784	$507,346	$335,972	$56,220	$15,880,934
1805-1	Land Station >50 kV		$121,229	$47,676	$12,841	$149,592	$81,603	$38,914	$1,748	$812	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$449,825	$176,905	$47,646	$555,067	$302,789	$144,392	$6,487	$3,011	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$2,140,539	$571,055	$224,581	$60,486	$704,659	$384,392	$183,307	$8,236	$3,823	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,140,539
1806-1	Land Rights Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$396,228	$155,826	$41,969	$488,930	$266,712	$127,188	$5,714	$2,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$1,485,219	$396,228	$155,826	$41,969	$488,930	$266,712	$127,188	$5,714	$2,653	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,485,219
1808-1	Buildings and Fixtures > 50 kV		$394,931	$155,316	$41,831	$487,329	$265,839	$126,772	$5,696	$2,644	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$13,058,373	$5,135,528	$1,383,147	$16,113,518	$8,789,940	$4,191,694	$188,326	$87,420	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$50,428,304	$13,453,304	$5,290,845	$1,424,978	$16,600,847	$9,055,779	$4,318,465	$194,021	$90,064	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,428,304
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$21,181,208	$5,650,740	$2,222,293	$598,528	$6,972,791	$3,803,664	$1,813,868	$81,494	$37,829	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,181,208
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$156,994,674	$38,322,249	$18,551,611	$6,140,146	$50,983,582	$28,975,316	$13,905,282	$0	$116,487	$0	$0	$0	$0	$0	$0	$0	$0	$0	$156,994,674
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,265,714	$4,632,564	$2,123,987	$546,644	$7,477,619	$4,203,236	$2,142,594	$91,118	$47,952	$21,265,714
1820	Total	$156,994,674	$38,322,249	$18,551,611	$6,140,146	$50,983,582	$28,975,316	$13,905,282	$0	$116,487	$21,265,714	$4,632,564	$2,123,987	$546,644	$7,477,619	$4,203,236	$2,142,594	$91,118	$47,952	$178,260,387
1815 & 1820	Total	$178,175,882	$43,972,989	$20,773,905	$6,738,674	$57,956,373	$32,778,981	$15,719,150	$81,494	$154,316	$21,265,714	$4,632,564	$2,123,987	$546,644	$7,477,619	$4,203,236	$2,142,594	$91,118	$47,952	$199,441,596
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$27,782,403	$13,449,324	$4,451,409	$36,961,464	$21,006,176	$10,080,884	$0	$84,449	$61,285,597	$47,881,172	$4,967,982	$79,113	$782,956	$39,816	$3,640	$6,597,308	$933,611	$61,285,597
1830-5	Poles, Towers and Fixtures - Secondary		$54,218,325	$26,246,823	$2,178,988	$17,204,549	$998,843	$0	$0	$164,806	$54,391,257	$42,984,285	$4,459,898	$17,814	$167,649	$871	$21	$5,922,590	$838,129	$54,391,257
1830	Total	$214,828,443	$82,000,728	$39,696,147	$6,630,397	$54,166,013	$22,005,019	$10,080,884	$0	$249,255	$115,676,854	$90,865,457	$9,427,880	$96,927	$950,605	$40,687	$3,661	$12,519,897	$1,771,739	$330,505,297
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$20,415,355	$9,882,972	$3,271,031	$27,160,408	$15,435,978	$7,407,740	$0	$62,056	$45,034,522	$35,184,543	$3,650,624	$58,134	$575,340	$29,258	$2,675	$4,847,902	$686,046	$45,034,522
1835-5	Overhead Conductors and Devices - Secondary		$39,841,276	$19,286,965	$1,601,187	$12,642,426	$733,980	$0	$0	$121,104	$39,968,351	$31,586,161	$3,277,269	$13,091	$123,193	$640	$16	$4,352,099	$615,883	$39,968,351
1835	Total	$157,862,478	$60,256,631	$29,169,937	$4,872,217	$39,802,835	$16,169,957	$7,407,740	$0	$183,160	$85,002,873	$66,770,703	$6,927,893	$71,225	$698,533	$29,898	$2,690	$9,200,002	$1,301,928	$242,865,350
1830 & 1835	Total	$372,690,920	$142,257,359	$68,866,084	$11,502,614	$93,968,847	$38,174,976	$17,488,624	$0	$432,415	$200,679,726	$157,636,160	$16,355,772	$168,152	$1,649,138	$70,586	$6,352	$21,719,899	$3,073,668	$573,370,647
1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$120,190,579	$58,183,665	$19,257,420	$159,900,486	$90,875,670	$43,611,320	$0	$365,340	$265,130,104	$207,140,679	$21,492,187	$342,253	$3,387,177	$172,251	$15,747	$28,540,879	$4,038,931	$265,130,104
1840-5	Underground Conduit - Secondary		$94,116,905	$45,561,529	$3,782,477	$29,865,159	$1,733,878	$0	$0	$286,084	$94,417,094	$74,615,876	$7,741,880	$30,924	$291,019	$1,512	$37	$10,280,949	$1,454,897	$94,417,094
1840	Total	$667,730,511	$214,307,484	$103,745,193	$23,039,898	$189,765,645	$92,609,548	$43,611,320	$0	$651,424	$359,547,198	$281,756,555	$29,234,067	$373,177	$3,678,197	$173,763	$15,784	$38,821,828	$5,493,828	$1,027,277,710

1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$55,878,505	$27,050,508	$8,953,080	$74,340,270	$42,249,539	$20,275,594	$0	$169,852	$123,263,187	$96,302,984	$9,992,058	$159,119	$1,574,752	$80,082	$7,321	$13,269,107	$1,877,763	$123,263,187
1845-5	Underground Conductors and Devices - Secondary		$43,756,441	$21,182,277	$1,758,534	$13,884,786	$806,107	$0	$0	$133,005	$43,896,003	$34,690,103	$3,599,323	$14,377	$135,299	$703	$17	$4,779,776	$676,405	$43,896,003
1845	Total	$310,438,496	$99,634,945	$48,232,784	$10,711,614	$88,225,055	$43,055,646	$20,275,594	$0	$302,857	$167,159,190	$130,993,087	$13,591,381	$173,496	$1,710,052	$80,785	$7,338	$18,048,883	$2,554,168	$477,597,685
1840 & 1845	Total	$978,169,007	$313,942,429	$151,977,978	$33,751,511	$277,990,700	$135,665,194	$63,886,914	$0	$954,281	$526,706,388	$412,749,642	$42,825,448	$546,672	$5,388,248	$254,548	$23,122	$56,870,711	$8,047,996	$1,504,875,395
1850	Line Transformers	$460,341,558	$159,801,507	$77,359,119	$21,407,616	$169,027,281	$29,439,592	$2,820,699	$0	$485,744	$197,289,239	$154,660,301	$16,047,008	$213,658	$2,010,703	$31,336	$720	$21,309,870	$3,015,643	$657,630,797
1815- 1850	Total	$1,989,377,367	$659,974,284	$318,977,086	$73,400,415	$598,943,202	$236,058,743	$99,915,387	$81,494	$2,026,757	$945,941,068	$729,678,668	$77,352,215	$1,475,127	$16,525,709	$4,559,706	$2,172,787	$99,991,598	$14,185,259	$2,935,318,435
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$324,780,992	$230,642,004	$47,861,203	$955,875	$8,995,572	$46,731	$3,427	$31,779,009	$4,497,171	$324,780,992
1815- 1855	Total	$1,989,377,367	$659,974,284	$318,977,086	$73,400,415	$598,943,202	$236,058,743	$99,915,387	$81,494	$2,026,757	$1,270,722,059	$960,320,671	$125,213,418	$2,431,001	$25,521,280	$4,606,437	$2,176,213	$131,770,607	$18,682,430	$3,260,099,427
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$281,071,517	$188,368,869	$27,531,641	$3,047,005	$53,573,045	$7,717,059	$833,898	$0	$0	$281,071,517
1815-1860	Total	$1,989,377,367	$659,974,284	$318,977,086	$73,400,415	$598,943,202	$236,058,743	$99,915,387	$81,494	$2,026,757	$1,551,793,576	$1,148,689,541	$152,745,059	$5,478,007	$79,094,325	$12,323,496	$3,010,111	$131,770,607	$18,682,430	$3,541,170,943
1565-1860	Total	$2,043,431,429	$674,394,870	$324,648,339	$74,927,848	$616,737,638	$245,765,626	$104,544,346	$289,465	$2,123,297	$1,567,674,510	$1,156,537,187	$155,270,466	$5,887,355	$82,117,536	$13,499,280	$3,517,457	$132,106,579	$18,738,651	$3,611,105,939

	Total Demand And Customer	$3,611,105,939	$1,830,932,057	$479,918,804	$80,815,203	$698,855,173	$259,264,906	$108,061,804	$132,396,045	$20,861,947
	Accum Depreciation - NFA	($1,963,225,933)	($999,442,382)	($265,593,280)	($44,474,526)	($375,857,445)	($135,660,889)	($55,671,005)	($74,767,599)	($11,758,808)
	Accum Depreciation - NFA ECC	($1,719,528,344)	($876,562,475)	($230,651,297)	($38,305,569)	($325,952,141)	($121,160,003)	($50,597,520)	($65,961,753)	($10,337,585)
NFA	Net Fixed Assets	$1,647,880,007	$831,489,676	$214,325,525	$36,340,676	$322,997,729	$123,604,017	$52,390,799	$57,628,446	$9,103,139
NFA ECC	Net Fixed Assets Excluding Capital Contribution	$1,891,577,596	$954,369,582	$249,267,507	$42,509,634	$372,903,032	$138,104,903	$57,464,284	$66,434,291	$10,524,363

Operating and Maintenance

Allocate all the costs to the O and M expenses before using it as a composite allocator.

Acccounts

O&M DC	Total	$75,279,877	$23,335,620	$10,756,957	$2,548,154	$22,999,044	$10,633,235	$4,828,513	$85,702	$92,652	$74,318,172	$52,811,284	$13,747,452	$1,423,810	$6,335,626	$775,575	$94,343	$3,174,285	$452,863
O&M	Total Demand and Customer	$154,095,114	$76,146,904	$24,504,409	$3,971,964	$29,334,670	$11,408,810	$4,922,856	$3,259,987	$545,515									

Accounts

4705	Power Purchased	$1,509,512,857	$331,772,680	$152,114,646	$39,149,264	$535,528,392	$301,025,220	$139,962,794	$6,525,625	$3,434,234	$1,509,512,857
4708	Charges-WMS	$138,665,047	$30,476,901	$13,973,372	$3,596,282	$49,194,063	$27,652,415	$12,857,093	$599,449	$315,471	$138,665,047
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$140,399,940	$30,584,996	$14,022,932	$3,609,038	$49,368,542	$27,750,492	$14,145,776	$601,575	$316,590	$140,399,940
4716	Charges-CN	$108,417,144	$23,617,801	$10,828,539	$2,786,907	$38,122,497	$21,428,991	$10,923,399	$464,538	$244,472	$108,417,144
4730	Rural Rate Assistance Expense	$26,666,355	$5,860,943	$2,687,187	$691,593	$9,460,397	$5,317,772	$2,472,518	$115,279	$60,668	$26,666,355
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power	$1,923,661,344	$422,313,321	$193,626,677	$49,833,084	$681,673,891	$383,174,890	$180,361,580	$8,306,466	$4,371,435	$1,923,661,344

Acccounts

	OM&A Expenses	**$204,231,496**	**$101,058,270**	**$32,107,237**	**$5,217,780**	**$38,958,804**	**$15,122,910**	**$6,515,058**	**$4,502,258**	**$749,179**	**$204,231,496**

Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)	Demand Allocators										Customer Allocators								
	Demand Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50- Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50- Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Total
1808	$ 21,954,295	$ 5,856,984	$ 2,303,404	$ 620,374	$ 7,227,288	$ 3,942,493	$ 1,880,072	$ 84,468	$ 39,210	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,574,793	$ 1,604,901	$ 776,924	$ 257,144	$ 2,135,146	$ 1,213,460	$ 582,340	$ -	$ 4,878	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 4,942,817	$ 1,886,690	$ 913,337	$ 152,554	$ 1,246,263	$ 506,296	$ 231,943	$ -	$ 5,735	$ 2,331,671	$ 2,090,651	$ 216,919	$ 2,230	$ 21,872	$ 936	$ 84	$ 288,060	$ 40,765	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 4,661,694	$ 1,496,166	$ 724,287	$ 160,851	$ 1,324,830	$ 646,544	$ 304,468	$ -	$ 4,548	$ 2,199,434	$ 1,967,055	$ 204,095	$ 2,605	$ 25,679	$ 1,213	$ 110	$ 271,031	$ 38,355	$ -
1850	$ 1,333,728	$ 462,986	$ 224,129	$ 62,023	$ 489,716	$ 85,294	$ 8,172	$ -	$ 1,407	$ 501,028	$ 448,091	$ 46,492	$ 619	$ 5,826	$ 91	$ 2	$ 61,740	$ 8,737	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 263,245	$ 210,485	$ 43,678	$ 872	$ 8,209	$ 43	$ 3	$ 29,002	$ 4,104	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 826,431	$ 571,237	$ 83,491	$ 9,240	$ 162,463	$ 23,402	$ 2,529	$ -	$ -	$ -
1815-1855	$ 30,112,352	$ 9,989,748	$ 4,828,219	$ 1,111,031	$ 9,065,946	$ 3,573,120	$ 1,512,376	$ 1,234	$ 30,678	$ 14,208,025	$ 12,253,639	$ 1,597,716	$ 31,019	$ 325,650	$ 58,778	$ 27,768	$ 1,681,386	$ 238,387	$ -
1830 & 1835	$ 3,434,686	$ 1,311,031	$ 634,664	$ 106,007	$ 866,008	$ 351,817	$ 161,174	$ -	$ 3,985	$ 1,620,242	$ 1,452,761	$ 150,733	$ 1,550	$ 15,198	$ 651	$ 59	$ 200,169	$ 28,327	$ -
1840 & 1845	$ 2,265,512	$ 727,114	$ 351,992	$ 78,171	$ 643,847	$ 314,211	$ 147,967	$ -	$ 2,210	$ 1,068,891	$ 955,959	$ 99,187	$ 1,266	$ 12,480	$ 590	$ 54	$ 131,717	$ 18,640	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,230,434	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,154,004	$ 3,703,111	$ 384,222	$ 6,119	$ 60,553	$ 3,079	$ 282	$ 510,233	$ 72,205	$ -

CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,349,436	$ 5,080,002	$ 742,484	$ 82,173	$ 1,444,778	$ 208,117	$ 22,489	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,621,397	$ 1,902,180	$ 707,451	$ 11,766	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,943,932	$ 17,961,834	$ 7,454,626	$ 415,490	$ 4,111,982	$ 209,110	$ 40,964	$ 947	$ 3,344	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 75,279,877**	**$ 23,335,620**	**$ 10,756,957**	**$ 2,548,154**	**$ 22,999,044**	**$ 10,633,235**	**$ 4,828,513**	**$ 85,702**	**$ 92,652**	**$ 74,318,172**	**$ 52,811,284**	**$ 13,747,452**	**$ 1,423,810**	**$ 6,335,626**	**$ 775,575**	**$ 94,343**	**$ 3,174,285**	**$ 452,863**	**$ -**		

Grouping of OM&A (lines 168 - 240)	**Demand Allocators**										**Customer Allocators**								
	Demand Total	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50- Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Customer Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50- Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Total**
1808	$ 21,954,295	$ 5,856,984	$ 2,303,404	$ 620,374	$ 7,227,288	$ 3,942,493	$ 1,880,072	$ 84,468	$ 39,210	$ 21,954,295	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,574,793	$ 1,604,901	$ 776,924	$ 257,144	$ 2,135,146	$ 1,213,460	$ 582,340	$ -	$ 4,878	$ 6,574,793	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 7,604,333	$ 3,977,341	$ 1,130,256	$ 154,784	$ 1,268,134	$ 507,232	$ 232,027	$ 288,060	$ 46,499	$ 7,604,333	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,171,837	$ 3,463,222	$ 928,382	$ 163,456	$ 1,350,509	$ 647,757	$ 304,578	$ 271,031	$ 42,902	$ 7,171,837	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ 1,905,326	$ 911,077	$ 270,622	$ 62,642	$ 495,541	$ 85,385	$ 8,174	$ 61,740	$ 10,144	$ 1,905,326	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 296,397	$ 210,485	$ 43,678	$ 872	$ 8,209	$ 43	$ 3	$ 29,002	$ 4,104	$ 296,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ 852,362	$ 571,237	$ 83,491	$ 9,240	$ 162,463	$ 23,402	$ 2,529	$ -	$ -	$ 852,362	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 46,326,696	$ 22,243,387	$ 6,425,936	$ 1,142,050	$ 9,391,597	$ 3,631,898	$ 1,540,145	$ 1,682,619	$ 269,065	$ 46,326,696	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 5,284,132	$ 2,763,791	$ 785,397	$ 107,557	$ 881,207	$ 352,468	$ 161,232	$ 200,169	$ 32,312	$ 5,284,132	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ 3,485,403	$ 1,683,073	$ 451,179	$ 79,437	$ 656,327	$ 314,800	$ 148,020	$ 131,717	$ 20,850	$ 3,485,403	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -	$ 7,500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 4,739,803	$ 3,703,111	$ 384,222	$ 6,119	$ 60,553	$ 3,079	$ 282	$ 510,233	$ 72,205	$ 4,739,803	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ 7,580,042	$ 5,080,002	$ 742,484	$ 82,173	$ 1,444,778	$ 208,117	$ 22,489	$ -	$ -	$ 7,580,042	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ 2,621,397	$ 1,902,180	$ 707,451	$ 11,766	$ -	$ -	$ -	$ -	$ -	$ 2,621,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ 30,198,298	$ 17,961,834	$ 7,454,626	$ 415,490	$ 4,111,982	$ 209,110	$ 40,964	$ 947	$ 3,344	$ 30,198,298	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ 7,795,116	$ 3,933,271	$ 1,013,843	$ 171,906	$ 1,527,905	$ 584,695	$ 247,829	$ 272,605	$ 43,061	$ 7,795,116	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 5,292,218	$ 2,670,116	$ 697,396	$ 118,933	$ 1,043,301	$ 386,387	$ 160,772	$ 185,869	$ 29,445	$ 5,292,218	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 37,049,047	$ 18,307,980	$ 5,891,589	$ 954,978	$ 7,052,927	$ 2,743,017	$ 1,183,601	$ 783,798	$ 131,158	$ 37,049,047	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 204,231,496**	**$ 101,058,270**	**$ 32,107,237**	**$ 5,217,780**	**$ 38,958,804**	**$ 15,122,910**	**$ 6,515,058**	**$ 4,502,258**	**$ 749,179**	**$ 204,231,496**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O6 Composite Allocator Detail Worksheet

Details:
Output Sheet Details How Various Composite Allocators are Derived

Demand Allocators can be found in columns C to AG
Customer Allocators can be found in columns AJ to BN

Composite allocators

Rate Base

		Demand Allocators									Customer Allocators									
			1	2	3	4	5	6	7	9		1	2	3	4	5	6	7	9	
		Demand Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,249,461	$8,165,702	$2,588,028	$174,738	$3,211,906	$1,200,877	$515,867	$336,085	$56,256	$16,249,461
1805-1	Land Station >50 kV		$124,530	$49,651	$2,944	$155,004	$81,466	$38,253	$1,756	$812	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$462,071	$184,231	$10,924	$575,146	$302,282	$141,939	$6,515	$3,015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$2,140,539	$586,601	$233,882	$13,868	$730,150	$383,749	$180,192	$8,270	$3,827	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,140,539
1806-1	Land Rights Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$407,015	$162,280	$9,622	$506,616	$266,265	$125,027	$5,738	$2,655	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$1,485,219	$407,015	$162,280	$9,622	$506,616	$266,265	$125,027	$5,738	$2,655	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,485,219
1808-1	Buildings and Fixtures > 50 kV		$405,683	$161,749	$9,591	$504,958	$265,393	$124,618	$5,720	$2,647	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV		$13,915,084	$5,548,044	$328,974	$17,320,280	$9,103,109	$4,274,441	$196,186	$90,784	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$52,257,261	$14,320,767	$5,709,793	$338,565	$17,825,238	$9,368,503	$4,399,059	$201,906	$93,431	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52,257,261
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$36,931,208	$10,120,761	$4,035,220	$239,270	$12,597,438	$6,620,901	$3,108,899	$142,691	$66,030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$36,931,208
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$168,272,904	$41,696,856	$21,453,588	$1,911,263	$56,950,549	$31,165,152	$14,972,249	$0	$123,247	$0	$0	$0	$0	$0	$0	$0	$0	$0	$168,272,904
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$27,265,714	$6,117,498	$2,722,472	$161,380	$9,943,311	$5,392,242	$2,750,321	$116,934	$61,555	$27,265,714
1820	Total	$168,272,904	$41,696,856	$21,453,588	$1,911,263	$56,950,549	$31,165,152	$14,972,249	$0	$123,247	$27,265,714	$6,117,498	$2,722,472	$161,380	$9,943,311	$5,392,242	$2,750,321	$116,934	$61,555	$195,538,618
1815 & 1820	Total	$205,204,112	$51,817,616	$25,488,808	$2,150,533	$69,547,986	$37,786,053	$18,081,148	$142,691	$189,276	$27,265,714	$6,117,498	$2,722,472	$161,380	$9,943,311	$5,392,242	$2,750,321	$116,934	$61,555	$232,469,826
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$29,327,776	$15,089,532	$1,344,300	$40,056,568	$21,920,228	$10,530,836	$0	$86,686	$63,730,114	$50,367,793	$4,950,225	$19,631	$838,434	$40,225	$3,630	$6,579,137	$931,039	$63,730,114
1830-5	Poles, Towers and Fixtures - Secondary		$56,038,896	$28,832,759	$646,124	$18,337,512	$1,020,515	$0	$0	$165,639	$56,560,777	$45,194,591	$4,441,794	$4,431	$180,243	$879	$21	$5,903,404	$835,414	$56,560,777
1830	Total	$223,397,370	$85,366,671	$43,922,291	$1,990,424	$58,394,079	$22,940,743	$10,530,836	$0	$252,325	$120,290,891	$95,562,384	$9,392,019	$24,062	$1,018,677	$41,105	$3,651	$12,482,541	$1,766,453	$343,688,261
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$21,454,031	$11,038,385	$983,391	$29,302,421	$16,035,217	$7,703,581	$0	$63,413	$46,620,236	$36,845,350	$3,621,218	$14,361	$613,336	$29,426	$2,655	$4,812,810	$681,080	$46,620,236
1835-5	Overhead Conductors and Devices - Secondary		$40,993,909	$21,091,913	$472,656	$13,414,367	$746,533	$0	$0	$121,169	$41,375,679	$33,061,018	$3,249,288	$3,241	$131,852	$643	$16	$4,318,493	$611,127	$41,375,679
1835	Total	$163,420,985	$62,447,940	$32,130,298	$1,456,047	$42,716,787	$16,781,750	$7,703,581	$0	$184,582	$87,995,915	$69,906,369	$6,870,506	$17,602	$745,188	$30,069	$2,671	$9,131,304	$1,292,206	$251,416,900
1830 & 1835	Total	$386,818,355	$147,814,611	$76,052,588	$3,446,471	$101,110,867	$39,722,494	$18,234,417	$0	$436,907	$208,286,806	$165,468,753	$16,262,525	$41,664	$1,763,865	$71,174	$6,322	$21,613,845	$3,058,659	$595,105,161
1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$129,260,997	$66,506,506	$5,924,950	$176,547,718	$96,612,529	$46,414,239	$0	$382,067	$280,887,927	$221,994,031	$21,817,917	$86,523	$3,695,362	$177,291	$15,999	$28,997,285	$4,103,519	$280,887,927
1840-5	Underground Conduit - Secondary		$99,105,752	$50,991,231	$1,142,681	$32,430,205	$1,804,798	$0	$0	$292,935	$100,028,708	$79,927,412	$7,855,390	$7,836	$318,763	$1,555	$38	$10,440,271	$1,477,443	$100,028,708
1840	Total	$707,416,608	$228,366,749	$117,497,737	$7,067,630	$208,977,923	$98,417,327	$46,414,239	$0	$675,002	$380,916,635	$301,921,443	$29,673,307	$94,359	$4,014,125	$178,846	$16,036	$39,437,556	$5,580,962	$1,088,333,243

1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$62,944,641	$32,385,857	$2,885,200	$85,971,275	$47,046,217	$22,601,772	$0	$186,050	$136,780,546	$108,101,709	$10,624,403	$42,133	$1,799,485	$86,333	$7,791	$14,120,452	$1,998,240	$136,780,546
1845-5	Underground Conductors and Devices - Secondary		$48,260,312	$24,830,574	$556,437	$15,792,139	$878,861	$0	$0	$142,647	$48,709,752	$38,921,271	$3,825,243	$3,816	$155,224	$757	$18	$5,083,971	$719,453	$48,709,752
1845	Total	$344,481,983	$111,204,953	$57,216,431	$3,441,637	$101,763,414	$47,925,078	$22,601,772	$0	$328,697	$185,490,298	$147,022,979	$14,449,646	$45,949	$1,954,709	$87,091	$7,809	$19,204,423	$2,717,693	$529,972,281
1840 & 1845	Total	$1,051,898,591	$339,571,702	$174,714,168	$10,509,267	$310,741,338	$146,342,405	$69,016,012	$0	$1,003,699	$566,406,934	$448,944,422	$44,122,953	$140,308	$5,968,834	$265,937	$23,845	$58,641,979	$8,298,655	$1,618,305,524
1850	Line Transformers	$490,583,064	$172,361,890	$88,682,490	$6,624,391	$188,005,617	$31,388,538	$3,010,674	$0	$509,464	$210,249,884	$166,705,173	$16,384,042	$54,479	$2,216,153	$32,438	$736	$21,775,348	$3,081,514	$700,832,948
1815- 1850	Total	$2,134,504,121	$711,565,819	$364,938,055	$22,730,662	$669,405,807	$255,239,489	$108,342,251	$142,691	$2,139,347	$1,012,209,338	$787,235,846	$79,491,992	$397,831	$19,892,163	$5,761,791	$2,781,224	$102,148,107	$14,500,384	$3,146,713,459
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$333,287,980	$240,339,125	$47,241,802	$235,627	$9,585,095	$46,766	$3,385	$31,393,556	$4,442,624	$333,287,980
1815- 1855	Total	$2,134,504,121	$711,565,819	$364,938,055	$22,730,662	$669,405,807	$255,239,489	$108,342,251	$142,691	$2,139,347	$1,345,497,319	$1,027,574,971	$126,733,794	$633,459	$29,477,258	$5,808,557	$2,784,608	$133,541,663	$18,943,009	$3,480,001,440
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$322,015,614	$217,866,269	$30,962,573	$827,455	$62,917,004	$8,532,216	$910,097	$0	$0	$322,015,614
1815-1860	Total	$2,134,504,121	$711,565,819	$364,938,055	$22,730,662	$669,405,807	$255,239,489	$108,342,251	$142,691	$2,139,347	$1,667,512,933	$1,245,441,240	$157,696,368	$1,460,914	$92,394,262	$14,340,773	$3,694,706	$133,541,663	$18,943,009	$3,802,017,054
1565-1860	Total	$2,190,387,140	$726,880,202	$371,044,009	$23,092,718	$688,467,811	$265,258,006	$113,046,529	$358,605	$2,239,260	$1,683,762,394	$1,253,606,942	$160,284,396	$1,635,652	$95,606,169	$15,541,650	$4,210,573	$133,877,748	$18,999,265	$3,874,149,534

	Total Demand And Customer	$3,874,149,534	$1,980,487,144	$531,328,405	$24,728,370	$784,073,980	$280,799,655	$117,257,102	$134,236,353	$21,238,525
	Accum Depreciation - NFA	($2,113,422,801)	($1,087,610,599)	($296,184,626)	($13,702,316)	($420,786,888)	($146,073,610)	($59,989,037)	($76,947,517)	($12,128,210)
	Accum Depreciation - NFA ECC	($1,849,801,906)	($953,617,013)	($256,593,040)	($11,765,795)	($364,390,229)	($130,414,591)	($54,541,363)	($67,827,821)	($10,652,054)
NFA	Net Fixed Assets	$1,760,726,733	$892,876,546	$235,143,779	$11,026,054	$363,287,092	$134,726,046	$57,268,065	$57,288,835	$9,110,316
NFA ECC	Net Fixed Assets Excluding Capital Contribution	$2,024,347,628	$1,026,870,131	$274,735,366	$12,962,575	$419,683,751	$150,385,064	$62,715,739	$66,408,531	$10,586,471

Operating and Maintenance

Allocate all the costs to the O and M expenses before using it as a composite allocator.

Acccounts

O&M DC	Total	$77,819,123	$24,387,460	$11,811,910	$722,702	$24,695,776	$11,029,353	$4,987,591	$89,575	$94,755	$77,923,012	$56,193,792	$13,727,419	$1,001,659	$7,000,142	$821,207	$103,122	$3,226,999	$460,395	
O&M	Total Demand and Customer	$160,353,857	$80,581,251	$25,539,329	$1,724,361	$31,695,918	$11,850,560	$5,090,713	$3,316,574	$555,151										

Accounts

4705	Power Purchased	$1,510,759,566	$323,440,644	$154,929,045	$365,047,905	$216,818,662	$300,337,429	$140,526,294	$6,443,679	$3,215,908	$1,510,759,566
4708	Charges-WMS	$138,779,602	$29,711,521	$14,231,908	$33,533,597	$19,917,139	$27,589,240	$12,908,860	$591,922	$295,416	$138,779,602
4710	Cost of Power Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4712	Charges-One-Time	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4714	Charges-NW	$140,680,487	$31,563,910	$14,046,899	$832,659	$51,303,622	$27,821,872	$14,190,586	$603,336	$317,602	$140,680,487
4716	Charges-CN	$108,646,489	$24,376,572	$10,848,315	$643,057	$39,621,404	$21,486,624	$10,959,284	$465,952	$245,282	$108,646,489
4730	Rural Rate Assistance Expense	$26,688,385	$5,713,754	$2,736,905	$6,448,769	$3,830,219	$5,305,623	$2,482,473	$113,831	$56,811	$26,688,385
5685	Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power	$1,925,554,529	$414,806,401	$196,793,072	$406,505,987	$331,491,046	$382,540,788	$181,067,497	$8,218,720	$4,131,019	$1,925,554,529

Acccounts

	OM&A Expenses	**$211,418,509**	**$106,304,602**	**$33,339,302**	**$2,214,055**	**$41,910,920**	**$15,647,434**	**$6,713,985**	**$4,533,030**	**$755,180**	**$211,418,509**

Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)	Demand Allocators										Customer Allocators								
	Demand Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50- Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Customer Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50- Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Total
1808	$ 22,661,092	$ 6,210,127	$ 2,476,022	$ 146,817	$ 7,729,823	$ 4,062,603	$ 1,907,629	$ 87,555	$ 40,516	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,971,478	$ 1,727,484	$ 888,813	$ 79,183	$ 2,359,438	$ 1,291,160	$ 620,294	$ -	$ 5,106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 5,399,518	$ 2,063,314	$ 1,061,602	$ 48,109	$ 1,411,386	$ 554,478	$ 254,530	$ -	$ 6,099	$ 2,561,952	$ 2,309,744	$ 227,005	$ 582	$ 24,621	$ 994	$ 88	$ 301,703	$ 42,695	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 5,063,227	$ 1,634,500	$ 840,972	$ 50,585	$ 1,495,728	$ 704,407	$ 332,203	$ -	$ 4,831	$ 2,402,745	$ 2,160,957	$ 212,382	$ 675	$ 28,730	$ 1,280	$ 115	$ 282,268	$ 39,945	$ -
1850	$ 1,458,048	$ 512,272	$ 263,571	$ 19,688	$ 558,766	$ 93,289	$ 8,948	$ -	$ 1,514	$ 550,903	$ 495,460	$ 48,695	$ 162	$ 6,587	$ 96	$ 2	$ 64,718	$ 9,158	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 275,286	$ 222,467	$ 43,729	$ 218	$ 8,872	$ 43	$ 3	$ 29,059	$ 4,112	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 871,001	$ 607,095	$ 86,279	$ 2,306	$ 175,321	$ 23,775	$ 2,536	$ -	$ -	$ -
1815-1855	$ 30,218,231	$ 10,073,656	$ 5,166,438	$ 321,799	$ 9,476,796	$ 3,613,432	$ 1,533,804	$ 2,020	$ 30,287	$ 14,323,410	$ 12,426,660	$ 1,532,616	$ 7,661	$ 356,474	$ 70,244	$ 33,675	$ 1,614,945	$ 229,081	$ -
1830 & 1835	$ 3,605,657	$ 1,377,827	$ 708,910	$ 32,126	$ 942,486	$ 370,266	$ 169,969	$ -	$ 4,073	$ 1,710,805	$ 1,542,387	$ 151,588	$ 388	$ 16,442	$ 663	$ 59	$ 201,470	$ 28,511	$ -
1840 & 1845	$ 2,441,873	$ 788,280	$ 405,581	$ 24,396	$ 721,354	$ 339,719	$ 160,213	$ -	$ 2,330	$ 1,158,786	$ 1,042,178	$ 102,427	$ 326	$ 13,856	$ 617	$ 55	$ 136,131	$ 19,264	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,230,434	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,086,946	$ 4,560,985	$ 448,261	$ 1,778	$ 75,923	$ 3,643	$ 329	$ 595,765	$ 84,309	$ -

CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,793,522	$ 6,129,160	$ 871,060	$ 23,279	$ 1,770,023	$ 240,034	$ 25,603	$ -	$ -	$ -	$ -
CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,682,132	$ 18,804,591	$ 7,392,577	$ 102,609	$ 4,382,356	$ 210,251	$ 40,656	$ 940	$ 3,319	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 77,819,123**	**$ 24,387,460**	**$ 11,811,910**	**$ 722,702**	**$ 24,695,776**	**$ 11,029,353**	**$ 4,987,591**	**$ 89,575**	**$ 94,755**	**$ 77,923,012**	**$ 56,193,792**	**$ 13,727,419**	**$ 1,001,659**	**$ 7,000,142**	**$ 821,207**	**$ 103,122**	**$ 3,226,999**	**$ 460,395**	**$ -**		

Grouping of OM&A (lines 168 - 240)	**Demand Allocators**										**Customer Allocators**								
	Demand Total	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Customer Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Total**
1808	$ 22,661,092	$ 6,210,127	$ 2,476,022	$ 146,817	$ 7,729,823	$ 4,062,603	$ 1,907,629	$ 87,555	$ 40,516	$ 22,661,092	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 6,971,478	$ 1,727,484	$ 888,813	$ 79,183	$ 2,359,438	$ 1,291,160	$ 620,294	$ -	$ 5,106	$ 6,971,478	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ 8,306,950	$ 4,373,058	$ 1,288,608	$ 48,690	$ 1,436,007	$ 555,472	$ 254,619	$ 301,703	$ 48,794	$ 8,306,950	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ 7,789,580	$ 3,795,457	$ 1,053,354	$ 51,261	$ 1,524,458	$ 705,687	$ 332,318	$ 282,268	$ 44,776	$ 7,789,580	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ 2,082,925	$ 1,007,731	$ 312,265	$ 19,850	$ 565,353	$ 93,385	$ 8,950	$ 64,718	$ 10,673	$ 2,082,925	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 308,503	$ 222,467	$ 43,729	$ 218	$ 8,872	$ 43	$ 3	$ 29,059	$ 4,112	$ 308,503	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ 897,312	$ 607,095	$ 86,279	$ 2,306	$ 175,321	$ 23,775	$ 2,536	$ -	$ -	$ 897,312	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 46,489,586	$ 22,500,316	$ 6,699,054	$ 329,459	$ 9,833,270	$ 3,683,676	$ 1,567,479	$ 1,616,965	$ 259,368	$ 46,489,586	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 5,547,164	$ 2,920,214	$ 860,498	$ 32,514	$ 958,928	$ 370,929	$ 170,028	$ 201,470	$ 32,583	$ 5,547,164	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ 3,756,727	$ 1,830,458	$ 508,007	$ 24,722	$ 735,210	$ 340,336	$ 160,269	$ 136,131	$ 21,594	$ 3,756,727	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 7,500,000	$ 4,214,279	$ 2,016,358	$ 858,861	$ 140,936	$ 269,566	$ -	$ -	$ -	$ 7,500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 5,770,991	$ 4,560,985	$ 448,261	$ 1,778	$ 75,923	$ 3,643	$ 329	$ 595,765	$ 84,309	$ 5,770,991	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	-$ 0	-$ 0	-$ 0	-$ 0	-$ 0	-$ 0	-$ 0	-$ 0	-$ 0	-$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ 9,059,160	$ 6,129,160	$ 871,060	$ 23,279	$ 1,770,023	$ 240,034	$ 25,603	$ -	$ -	$ 9,059,160	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ 2,275,089	$ 1,677,830	$ 594,443	$ 2,815	$ -	$ -	$ -	$ -	$ -	$ 2,275,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ 30,937,299	$ 18,804,591	$ 7,392,577	$ 102,609	$ 4,382,356	$ 210,251	$ 40,656	$ 940	$ 3,319	$ 30,937,299	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ 8,028,970	$ 4,071,545	$ 1,072,263	$ 50,279	$ 1,656,601	$ 614,355	$ 261,144	$ 261,239	$ 41,543	$ 8,028,970	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 5,371,741	$ 2,724,868	$ 729,028	$ 34,397	$ 1,113,659	$ 399,057	$ 166,420	$ 176,219	$ 28,092	$ 5,371,741	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 37,663,941	$ 18,926,938	$ 5,998,682	$ 405,018	$ 7,444,743	$ 2,783,462	$ 1,195,707	$ 778,998	$ 130,394	$ 37,663,941	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 211,418,509**	**$ 106,304,602**	**$ 33,339,302**	**$ 2,214,055**	**$ 41,910,920**	**$ 15,647,434**	**$ 6,713,985**	**$ 4,533,030**	**$ 755,180**	**$ 211,418,509**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Ontario

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Contributed Capital**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Total**
1830-4	Poles, Towers and Fixtures - Primary	($5,172,777)	($3,362,305)	($1,810,472)	($5,172,777)	($783,607)	($420,928)	($225,294)	($1,018,573)	($616,639)	($296,438)	$0	($827)	($3,362,305)
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	($4,998,228)	($3,248,848)	($1,749,380)	($4,998,228)	($757,165)	($406,724)	($217,692)	($984,202)	($595,831)	($286,435)	$0	($799)	($3,248,848)
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($29,937,354)	($19,459,280)	($10,478,074)	($29,937,354)	($4,535,110)	($2,436,114)	($1,303,886)	($5,894,972)	($3,568,786)	($1,715,628)	$0	($4,785)	($19,459,280)
1840-5	Underground Conduit - Secondary	($44,906,032)	($29,188,921)	($15,717,111)	($44,906,032)	($15,063,811)	($8,091,791)	($1,084,910)	($4,643,681)	($288,835)	$0	$0	($15,893)	($29,188,921)
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($35,240,045)	($22,906,029)	($12,334,016)	($35,240,045)	($5,338,397)	($2,867,614)	($1,534,838)	($6,939,126)	($4,200,911)	($2,019,510)	$0	($5,632)	($22,906,029)
1845-5	Underground Conductors and Devices - Secondary	($11,746,682)	($7,635,343)	($4,111,339)	($11,746,682)	($3,940,446)	($2,116,680)	($283,795)	($1,214,711)	($75,554)	$0	$0	($4,157)	($7,635,343)
1850	Line Transformers	($82,833,694)	($57,983,586)	($24,850,108)	($82,833,694)	($19,225,379)	($10,327,251)	($4,615,432)	($19,755,188)	($3,686,291)	($353,760)	$0	($20,284)	($57,983,586)
1855	Services	($2,989,970)	$0	($2,989,970)	($2,989,970)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($2,049,477)	$0	($2,049,477)	($2,049,477)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($219,874,258)**	**($143,784,312)**	**($76,089,946)**	**($219,874,258)**	**($49,643,915)**	**($26,667,102)**	**($9,265,845)**	**($40,450,453)**	**($13,032,848)**	**($4,671,770)**	**$0**	**($52,378)**	**($143,784,312)**
General Plant														
	Sub - Total	$0												
	TOTAL - 1995	($219,874,258)	($143,784,312)	($76,089,946)	($219,874,258)	($49,643,915)	($26,667,102)	($9,265,845)	($40,450,453)	($13,032,848)	($4,671,770)	$0	($52,378)	($143,784,312)

Accumulated Depreciation - 2105 Capital Contribution

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1830-4	Poles, Towers and Fixtures - Primary	$1,057,756	$687,541	$370,214	$1,057,756	$160,236	$86,074	$46,069	$208,283	$126,093	$60,617	$0	$169	$687,541
1835-4	Overhead Conductors and Devices - Primary	$1,015,698	$660,203	$355,494	$1,015,698	$153,865	$82,651	$44,237	$200,001	$121,080	$58,207	$0	$162	$660,203
1840-4	Underground Conduit - Primary	$4,132,088	$2,685,857	$1,446,231	$4,132,088	$625,956	$336,243	$179,968	$813,651	$492,580	$236,799	$0	$660	$2,685,857
1840-5	Underground Conduit - Secondary	$6,198,132	$4,028,786	$2,169,346	$6,198,132	$2,079,175	$1,116,865	$149,744	$640,942	$39,866	$0	$0	$2,194	$4,028,786
1845-4	Underground Conductors and Devices - Primary	$5,967,607	$3,878,944	$2,088,662	$5,967,607	$904,013	$485,606	$259,912	$1,175,083	$711,389	$341,987	$0	$954	$3,878,944
1845-5	Underground Conductors and Devices - Secondary	$1,989,202	$1,292,981	$696,221	$1,989,202	$667,282	$358,442	$48,058	$205,701	$12,795	$0	$0	$704	$1,292,981
1850	Line Transformers	$9,315,694	$6,520,986	$2,794,708	$9,315,694	$2,162,136	$1,161,430	$519,064	$2,221,720	$414,570	$39,785	$0	$2,281	$6,520,986
1855	Services	$382,127	$0	$382,127	$382,127	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$491,028	$0	$491,028	$491,028	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$30,549,331**	**$19,755,299**	**$10,794,031**	**$30,549,331**	**$6,752,663**	**$3,627,311**	**$1,247,053**	**$5,465,381**	**$1,918,373**	**$737,395**	**$0**	**$7,125**	**$19,755,299**
General Plant														
	Sub - Total	**$0**												
	TOTAL - 2105 CC	$30,549,331	$19,755,299	$10,794,031	$30,549,331	$6,752,663	$3,627,311	$1,247,053	$5,465,381	$1,918,373	$737,395	$0	$7,125	$19,755,299

Accumulated Depreciation - 2105 Fixed Assets Only

		Demand Allocation 1	2	3	4	5	6	7	9	Sub -total

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($2,523,488)	$0	($2,523,488)	($2,523,488)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	($499,244)	($499,244)	$0	($499,244)	($124,846)	($54,871)	($28,264)	($155,130)	($90,633)	($42,676)	($1,928)	($896)	($499,244)
1808-2	Buildings and Fixtures < 50 kV	($15,336,338)	($15,336,338)	$0	($15,336,338)	($3,835,146)	($1,685,579)	($868,261)	($4,765,470)	($2,784,157)	($1,310,958)	($59,242)	($27,524)	($15,336,338)
1815	Transformer Station Equipment - Normally Primary above 50 kV	($2,829,051)	($2,829,051)	$0	($2,829,051)	($707,459)	($310,934)	($160,166)	($879,073)	($513,586)	($241,829)	($10,928)	($5,077)	($2,829,051)
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($74,604,025)	($74,604,025)	$0	($74,604,025)	($17,386,946)	($9,339,704)	($4,998,906)	($22,600,458)	($13,682,201)	($6,577,465)	$0	($18,344)	($74,604,025)
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($479,132)	$0	($479,132)	($479,132)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	($74,103,283)	($48,167,134)	($25,936,149)	($74,103,283)	($11,225,660)	($6,030,061)	($3,227,480)	($14,591,697)	($8,833,738)	($4,246,656)	$0	($11,844)	($48,167,134)
1830-5	Poles, Towers and Fixtures - Secondary	($65,767,014)	($42,748,559)	($23,018,455)	($65,767,014)	($22,061,666)	($11,850,812)	($1,588,902)	($6,800,891)	($423,012)	$0	$0	($23,277)	($42,748,559)
1835-4	Overhead Conductors and Devices - Primary	($80,839,270)	($52,545,525)	($28,293,744)	($80,839,270)	($12,246,072)	($6,578,193)	($3,520,857)	($15,918,081)	($9,636,725)	($4,632,677)	$0	($12,920)	($52,545,525)
1835-5	Overhead Conductors and Devices - Secondary	($71,745,233)	($46,634,402)	($25,110,832)	($71,745,233)	($24,067,070)	($12,928,050)	($1,733,333)	($7,419,092)	($461,464)	$0	$0	($25,392)	($46,634,402)
1840-4	Underground Conduit - Primary	($349,571,990)	($227,221,793)	($122,350,196)	($349,571,990)	($52,955,496)	($28,445,977)	($15,225,189)	($68,834,310)	($41,671,938)	($20,033,012)	$0	($55,872)	($227,221,793)
1840-5	Underground Conduit - Secondary	($124,488,208)	($80,917,335)	($43,570,873)	($124,488,208)	($41,759,798)	($22,432,010)	($3,007,579)	($12,873,182)	($800,706)	$0	$0	($44,060)	($80,917,335)
1845-4	Underground Conductors and Devices - Primary	($153,456,452)	($99,746,694)	($53,709,758)	($153,456,452)	($23,246,607)	($12,487,324)	($6,683,612)	($30,217,150)	($18,293,307)	($8,794,168)	$0	($24,527)	($99,746,694)
1845-5	Underground Conductors and Devices - Secondary	($54,648,311)	($35,521,402)	($19,126,909)	($54,648,311)	($18,331,876)	($9,847,290)	($1,320,279)	($5,651,119)	($351,497)	$0	$0	($19,341)	($35,521,402)
1850	Line Transformers	($300,902,650)	($210,631,855)	($90,270,795)	($300,902,650)	($69,838,339)	($37,514,893)	($16,766,072)	($71,762,928)	($13,390,866)	($1,285,073)	$0	($73,684)	($210,631,855)
1855	Services	($162,072,047)	$0	($162,072,047)	($162,072,047)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($92,274,863)	$0	($92,274,863)	($92,274,863)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($1,626,140,598)**	**($937,403,357)**	**($688,737,241)**	**($1,626,140,598)**	**($297,786,980)**	**($159,505,697)**	**($59,128,898)**	**($262,468,580)**	**($110,933,830)**	**($47,164,513)**	**($72,098)**	**($342,760)**	**($937,403,357)**
General Plant														
1908	Buildings and Fixtures	($30,903,334)												
1915	Office Furniture and Equipment	($18,242,930)												
1920	Computer Equipment - Hardware	($38,982,514)												
1925	Computer Software	($95,041,935)												
1930	Transportation Equipment	($49,780,353)												
1935	Stores Equipment	($5,456,647)												
1940	Tools, Shop and Garage Equipment	($21,741,205)												
1945	Measurement and Testing Equipment	($4,028,728)												
1955	Communication Equipment	($22,354,831)												
1960	Miscellaneous Equipment	($104,582)												
1970	Load Management Controls - Customer Premises	($4,114,792)												
1975	Load Management Controls - Utility Premises	($525,613)												
1980	System Supervisory Equipment	($30,486,551)												
2005	Property Under Capital Leases	($571,810)												
	Sub - Total	**($322,335,822)**												
	TOTAL - 2105 FA	($1,948,476,420)	($937,403,357)	($688,737,241)	($1,626,140,598)	($297,786,980)	($159,505,697)	($59,128,898)	($262,468,580)	($110,933,830)	($47,164,513)	($72,098)	($342,760)	($937,403,357)

Accumulated Depreciation - 2120

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Demand Allocation 1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	Sub -total
1806-2	Land Rights Station <50 kV	($212,548)	($212,548)	$0	($212,548)	($53,152)	($23,361)	($12,033)	($66,045)	($38,586)	($18,169)	($821)	($381)	($212,548)
1815	Transformer Station Equipment - Normally Primary above 50 kV	($374,993)	($374,993)	$0	($374,993)	($93,774)	($41,215)	($21,230)	($116,522)	($68,076)	($32,055)	($1,449)	($673)	($374,993)
	Sub - Total	**($587,541)**	**($587,541)**	**$0**	**($587,541)**	**($146,926)**	**($64,575)**	**($33,263)**	**($182,567)**	**($106,662)**	**($50,223)**	**($2,270)**	**($1,054)**	**($587,541)**
General Plant														
1906	Land Rights	($2,104,231)												
1910	Leasehold Improvements	($2,702,274)												
	Sub - Total	**($4,806,505)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 2120	($5,394,046)	($587,541)	$0	($587,541)	($146,926)	($64,575)	($33,263)	($182,567)	($106,662)	($50,223)	($2,270)	($1,054)	($587,541)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total

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Toronto Hydro-Electric System Limited
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Sheet O7 Amortization Output Worksheet

Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	$1,498,023	$0	$1,498,023	$1,498,023	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$29,423	$29,423	$0	$29,423	$7,358	$3,234	$1,666	$9,143	$5,341	$2,515	$114	$53	$29,423
1808-2	Buildings and Fixtures < 50 KV	$909,337	$909,337	$0	$909,337	$227,397	$99,943	$51,482	$282,559	$165,081	$77,731	$3,513	$1,632	$909,337
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717	$52,444	$23,049	$11,873	$65,166	$38,072	$17,927	$810	$376	$209,717
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$3,881,489	$3,881,489	$0	$3,881,489	$904,606	$485,925	$260,082	$1,175,854	$711,856	$342,212	$0	$954	$3,881,489
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$425,481	$0	$425,481	$425,481	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$6,159,699	$4,003,804	$2,155,895	$6,159,699	$933,112	$501,238	$268,278	$1,212,908	$734,288	$352,995	$0	$984	$4,003,804
1830-5	Poles, Towers and Fixtures - Secondary	$5,650,396	$3,672,758	$1,977,639	$5,650,396	$1,895,436	$1,018,167	$136,511	$584,301	$36,343	$0	$0	$2,000	$3,672,758
1835-4	Overhead Conductors and Devices - Primary	$4,468,209	$2,904,336	$1,563,873	$4,468,209	$676,874	$363,595	$194,607	$879,836	$532,648	$256,061	$0	$714	$2,904,336
1835-5	Overhead Conductors and Devices - Secondary	$4,142,994	$2,692,946	$1,450,048	$4,142,994	$1,389,775	$746,542	$100,093	$428,422	$26,648	$0	$0	$1,466	$2,692,946
1840-4	Underground Conduit - Primary	$25,461,719	$16,550,117	$8,911,602	$25,461,719	$3,857,111	$2,071,915	$1,108,955	$5,013,674	$3,035,252	$1,459,141	$0	$4,070	$16,550,117
1840-5	Underground Conduit - Secondary	$7,978,128	$5,185,783	$2,792,345	$7,978,128	$2,676,278	$1,437,610	$192,748	$825,009	$51,315	$0	$0	$2,824	$5,185,783
1845-4	Underground Conductors and Devices - Primary	$10,821,565	$7,034,017	$3,787,548	$10,821,565	$1,639,323	$880,591	$471,320	$2,130,877	$1,290,022	$620,154	$0	$1,730	$7,034,017
1845-5	Underground Conductors and Devices - Secondary	$3,885,749	$2,525,737	$1,360,012	$3,885,749	$1,303,482	$700,188	$93,878	$401,821	$24,993	$0	$0	$1,375	$2,525,737
1850	Line Transformers	$18,815,588	$13,170,912	$5,644,676	$18,815,588	$4,367,025	$2,345,824	$1,048,391	$4,487,371	$837,337	$80,356	$0	$4,608	$13,170,912
1855	Services	$11,574,589	$0	$11,574,589	$11,574,589	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$15,082,855	$0	$15,082,855	$15,082,855	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$120,994,961**	**$62,770,376**	**$58,224,585**	**$120,994,961**	**$19,930,220**	**$10,677,821**	**$3,939,884**	**$17,496,939**	**$7,489,198**	**$3,209,092**	**$4,436**	**$22,786**	**$62,770,376**
General Plant														
1908	Buildings and Fixtures	$2,352,037												
1915	Office Furniture and Equipment	$727,474												
1920	Computer Equipment - Hardware	$3,205,553												
1925	Computer Software	$14,468,034												
1930	Transportation Equipment	$4,352,125												
1935	Stores Equipment	$7,851												
1940	Tools, Shop and Garage Equipment	$1,374,300												
1945	Measurement and Testing Equipment	$94,355												
1955	Communication Equipment	$1,167,482												
1970	Load Management Controls - Customer Premises	$293,937												
1975	Load Management Controls - Utility Premises	$41,365												
1980	System Supervisory Equipment	$2,084,497												
2005	Property Under Capital Leases	$243,333												
	Sub - Total	**$30,412,343**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$151,407,304	$62,770,376	$58,224,585	$120,994,961	$19,930,220	$10,677,821	$3,939,884	$17,496,939	$7,489,198	$3,209,092	$4,436	$22,786	$62,770,376

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$28,604	$28,604	$0	$28,604	$7,153	$3,144	$1,619	$8,888	$5,193	$2,445	$110	$51	$28,604
	Sub - Total	**$28,604**	**$28,604**	**$0**	**$28,604**	**$7,153**	**$3,144**	**$1,619**	**$8,888**	**$5,193**	**$2,445**	**$110**	**$51**	**$28,604**
General Plant														
	Sub - Total	**$500,661**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$529,265	$28,604	$0	$28,604	$7,153	$3,144	$1,619	$8,888	$5,193	$2,445	$110	$51	$28,604

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

		Demand Allocation 1	2	3	4	5	6	7	9	Sub -total

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Sheet O7 Amortization Output Worksheet

Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1815	Transformer Station Equipment - Normally Primary above 50 kV	$191,700	$191,700	$0	$191,700	$47,938	$21,069	$10,853	$59,567	$34,801	$16,387	$741	$344	$191,700
	Sub - Total	**$191,700**	**$191,700**	**$0**	**$191,700**	**$47,938**	**$21,069**	**$10,853**	**$59,567**	**$34,801**	**$16,387**	**$741**	**$344**	**$191,700**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$191,700	$191,700	$0	$191,700	$47,938	$21,069	$10,853	$59,567	$34,801	$16,387	$741	$344	$191,700

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%	100.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%	100.00%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	51.61%	27.72%	3.72%	15.91%	0.99%	0.00%	0.00%	0.05%	100.00%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%	100.00%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	51.61%	27.72%	3.72%	15.91%	0.99%	0.00%	0.00%	0.05%	100.00%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%

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Toronto Hydro-Electric System Limited
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1840-4	Underground Conduit - Primary	100%	65%	35%	100%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%	100.00%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	51.61%	27.72%	3.72%	15.91%	0.99%	0.00%	0.00%	0.05%	100.00%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%	100.00%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%	100.00%
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	51.61%	27.72%	3.72%	15.91%	0.99%	0.00%	0.00%	0.05%	100.00%
1850	Line Transformers	100%	70%	30%	100%	33.16%	17.81%	7.96%	34.07%	6.36%	0.61%	0.00%	0.03%	100.00%
1855	Services	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1860	Meters	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Plant														
1905	Land	100%												
1906	Land Rights	100%												
1908	Buildings and Fixtures	100%												
1910	Leasehold Improvements	100%												
1915	Office Furniture and Equipment	100%												
1920	Computer Equipment - Hardware	100%												
1925	Computer Software	100%												
1930	Transportation Equipment	100%												
1935	Stores Equipment	100%												
1940	Tools, Shop and Garage Equipment	100%												
1945	Measurement and Testing Equipment	100%												
1950	Power Operated Equipment	100%												
1955	Communication Equipment	100%												
1960	Miscellaneous Equipment	100%												
1970	Load Management Controls - Customer Premises	100%												
1975	Load Management Controls - Utility Premises	100%												
1980	System Supervisory Equipment	100%												
1990	Other Tangible Property	100%												
2005	Property Under Capital Leases	100%												
2010	Electric Plant Purchased or Sold	100%												

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Ontario

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	($5,172,777)	($3,362,305)	($1,810,472)	($5,172,777)	($1,391,833)	($150,952)	($4,815)	($21,314)	($1,191)	($111)	($200,291)	($39,965)	($1,810,472)
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	($4,998,228)	($3,248,848)	($1,749,380)	($4,998,228)	($1,344,868)	($145,858)	($4,652)	($20,595)	($1,151)	($107)	($193,533)	($38,616)	($1,749,380)
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	($29,937,354)	($19,459,280)	($10,478,074)	($29,937,354)	($8,055,212)	($873,631)	($27,866)	($123,356)	($6,892)	($640)	($1,159,181)	($231,297)	($10,478,074)
1840-5	Underground Conduit - Secondary	($44,906,032)	($29,188,921)	($15,717,111)	($44,906,032)	($12,225,568)	($1,325,929)	($10,594)	($44,400)	($255)	($6)	($1,759,314)	($351,044)	($15,717,111)
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	($35,240,045)	($22,906,029)	($12,334,016)	($35,240,045)	($9,482,001)	($1,028,374)	($32,802)	($145,205)	($8,112)	($753)	($1,364,503)	($272,265)	($12,334,016)
1845-5	Underground Conductors and Devices - Secondary	($11,746,682)	($7,635,343)	($4,111,339)	($11,746,682)	($3,198,008)	($346,841)	($2,771)	($11,614)	($67)	($2)	($460,208)	($91,827)	($4,111,339)
1850	Line Transformers	($82,833,694)	($57,983,586)	($24,850,108)	($82,833,694)	($19,170,301)	($2,079,122)	($55,375)	($232,072)	($3,996)	($93)	($2,758,693)	($550,455)	($24,850,108)
1855	Services	($2,989,970)	$0	($2,989,970)	($2,989,970)	($2,083,985)	($452,039)	($18,059)	($75,685)	($434)	($32)	($299,895)	($59,839)	($2,989,970)
1860	Meters	($2,049,477)	$0	($2,049,477)	($2,049,477)	($1,384,816)	($170,346)	($48,243)	($379,559)	($59,938)	($6,575)	$0	$0	($2,049,477)
	Sub - Total	**($219,874,258)**	**($143,784,312)**	**($76,089,946)**	**($219,874,258)**	**($58,336,594)**	**($6,573,093)**	**($205,180)**	**($1,053,801)**	**($82,035)**	**($8,318)**	**($8,195,617)**	**($1,635,309)**	**($76,089,946)**
General Plant														
	Sub - Total	$0												
	TOTAL - 1995	($219,874,258)	($143,784,312)	($76,089,946)	($219,874,258)	($58,336,594)	($6,573,093)	($205,180)	($1,053,801)	($82,035)	($8,318)	($8,195,617)	($1,635,309)	($76,089,946)

Accumulated Depreciation - 2105 Capital Contribution

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,057,756	$687,541	$370,214	$1,057,756	$284,609	$30,867	$985	$4,358	$243	$23	$40,957	$8,172	$370,214
1835-4	Overhead Conductors and Devices - Primary	$1,015,698	$660,203	$355,494	$1,015,698	$273,293	$29,640	$945	$4,185	$234	$22	$39,328	$7,847	$355,494
1840-4	Underground Conduit - Primary	$4,132,088	$2,685,857	$1,446,231	$4,132,088	$1,111,817	$120,582	$3,846	$17,026	$951	$88	$159,995	$31,925	$1,446,231
1840-5	Underground Conduit - Secondary	$6,198,132	$4,028,786	$2,169,346	$6,198,132	$1,687,428	$183,011	$1,462	$6,128	$35	$1	$242,828	$48,453	$2,169,346
1845-4	Underground Conductors and Devices - Primary	$5,967,607	$3,878,944	$2,088,662	$5,967,607	$1,605,698	$174,147	$5,555	$24,589	$1,374	$127	$231,067	$46,106	$2,088,662
1845-5	Underground Conductors and Devices - Secondary	$1,989,202	$1,292,981	$696,221	$1,989,202	$541,556	$58,735	$469	$1,967	$11	$0	$77,932	$15,550	$696,221
1850	Line Transformers	$9,315,694	$6,520,986	$2,794,708	$9,315,694	$2,155,942	$233,824	$6,228	$26,099	$449	$10	$310,250	$61,906	$2,794,708
1855	Services	$382,127	$0	$382,127	$382,127	$266,339	$57,772	$2,308	$9,673	$56	$4	$38,327	$7,648	$382,127
1860	Meters	$491,028	$0	$491,028	$491,028	$331,784	$40,813	$11,558	$90,937	$14,360	$1,575	$0	$0	$491,028
	Sub - Total	**$30,549,331**	**$19,755,299**	**$10,794,031**	**$30,549,331**	**$8,258,465**	**$929,390**	**$33,357**	**$184,964**	**$17,714**	**$1,851**	**$1,140,685**	**$227,606**	**$10,794,031**
General Plant														
	Sub - Total	**$0**												
	TOTAL - 2105 CC	$30,549,331	$19,755,299	$10,794,031	$30,549,331	$8,258,465	$929,390	$33,357	$184,964	$17,714	$1,851	$1,140,685	$227,606	$10,794,031

Accumulated Depreciation - 2105 Fixed Assets Only

	Customer Allocation 1	2	3	4	5	6	7	9	Sub -total

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($2,523,488)	$0	($2,523,488)	($2,523,488)	($1,216,957)	($418,260)	($107,504)	($447,407)	($186,702)	($80,392)	($54,638)	($11,630)	($2,523,488)
1808-1	Buildings and Fixtures > 50 kV	($499,244)	($499,244)	$0	($499,244)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 kV	($15,336,338)	($15,336,338)	$0	($15,336,338)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($2,829,051)	($2,829,051)	$0	($2,829,051)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($74,604,025)	($74,604,025)	$0	($74,604,025)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($479,132)	$0	($479,132)	($479,132)	($102,239)	($47,885)	($25,372)	($157,777)	($94,577)	($48,155)	($2,049)	($1,077)	($479,132)
1830-4	Poles, Towers and Fixtures - Primary	($74,103,283)	($48,167,134)	($25,936,149)	($74,103,283)	($19,938,891)	($2,162,480)	($68,977)	($305,340)	($17,058)	($1,583)	($2,869,296)	($572,524)	($25,936,149)
1830-5	Poles, Towers and Fixtures - Secondary	($65,767,014)	($42,748,559)	($23,018,455)	($65,767,014)	($17,904,925)	($1,941,886)	($15,516)	($65,026)	($373)	($9)	($2,576,599)	($514,121)	($23,018,455)
1835-4	Overhead Conductors and Devices - Primary	($80,839,270)	($52,545,525)	($28,293,744)	($80,839,270)	($21,751,336)	($2,359,050)	($75,247)	($333,095)	($18,609)	($1,727)	($3,130,115)	($624,566)	($28,293,744)
1835-5	Overhead Conductors and Devices - Secondary	($71,745,233)	($46,634,402)	($25,110,832)	($71,745,233)	($19,532,482)	($2,118,403)	($16,926)	($70,937)	($407)	($10)	($2,810,812)	($560,854)	($25,110,832)
1840-4	Underground Conduit - Primary	($349,571,990)	($227,221,793)	($122,350,196)	($349,571,990)	($94,058,961)	($10,201,201)	($325,389)	($1,440,397)	($80,471)	($7,468)	($13,535,507)	($2,700,802)	($122,350,196)
1840-5	Underground Conduit - Secondary	($124,488,208)	($80,917,335)	($43,570,873)	($124,488,208)	($33,891,641)	($3,675,731)	($29,370)	($123,086)	($707)	($18)	($4,877,159)	($973,162)	($43,570,873)
1845-4	Underground Conductors and Devices - Primary	($153,456,452)	($99,746,694)	($53,709,758)	($153,456,452)	($41,290,364)	($4,478,162)	($142,840)	($632,311)	($35,325)	($3,278)	($5,941,869)	($1,185,608)	($53,709,758)
1845-5	Underground Conductors and Devices - Secondary	($54,648,311)	($35,521,402)	($19,126,909)	($54,648,311)	($14,877,882)	($1,613,586)	($12,893)	($54,033)	($310)	($8)	($2,140,994)	($427,202)	($19,126,909)
1850	Line Transformers	($300,902,650)	($210,631,855)	($90,270,795)	($300,902,650)	($69,638,262)	($7,552,645)	($201,157)	($843,029)	($14,517)	($339)	($10,021,259)	($1,999,588)	($90,270,795)
1855	Services	($162,072,047)	$0	($162,072,047)	($162,072,047)	($112,962,939)	($24,502,878)	($978,916)	($4,102,529)	($23,548)	($1,753)	($16,255,875)	($3,243,609)	($162,072,047)
1860	Meters	($92,274,863)	$0	($92,274,863)	($92,274,863)	($62,349,418)	($7,669,603)	($2,172,078)	($17,089,130)	($2,698,608)	($296,027)	$0	$0	($92,274,863)
	Sub - Total	**($1,626,140,598)**	**($937,403,357)**	**($688,737,241)**	**($1,626,140,598)**	**($509,516,297)**	**($68,741,769)**	**($4,172,185)**	**($25,664,096)**	**($3,171,212)**	**($440,766)**	**($64,216,173)**	**($12,814,744)**	**($688,737,241)**
General Plant														
1908	Buildings and Fixtures	($30,903,334)												
1915	Office Furniture and Equipment	($18,242,930)												
1920	Computer Equipment - Hardware	($38,982,514)												
1925	Computer Software	($95,041,935)												
1930	Transportation Equipment	($49,780,353)												
1935	Stores Equipment	($5,456,647)												
1940	Tools, Shop and Garage Equipment	($21,741,205)												
1945	Measurement and Testing Equipment	($4,028,728)												
1955	Communication Equipment	($22,354,831)												
1960	Miscellaneous Equipment	($104,582)												
1970	Load Management Controls - Customer Premises	($4,114,792)												
1975	Load Management Controls - Utility Premises	($525,613)												
1980	System Supervisory Equipment	($30,486,551)												
2005	Property Under Capital Leases	($571,810)												
	Sub - Total	**($322,335,822)**												
	TOTAL - 2105 FA	($1,948,476,420)	($937,403,357)	($688,737,241)	($1,626,140,598)	($509,516,297)	($68,741,769)	($4,172,185)	($25,664,096)	($3,171,212)	($440,766)	($64,216,173)	($12,814,744)	($688,737,241)

Accumulated Depreciation - 2120

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Customer Allocation 1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	Sub -total
1806-2	Land Rights Station <50 kV	($212,548)	($212,548)	$0	($212,548)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($374,993)	($374,993)	$0	($374,993)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($587,541)**	**($587,541)**	**$0**	**($587,541)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	($2,104,231)												
1910	Leasehold Improvements	($2,702,274)												
	Sub - Total	**($4,806,505)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 2120	($5,394,046)	($587,541)	$0	($587,541)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	$1,498,023	$0	$1,498,023	$1,498,023	$722,424	$248,292	$63,818	$265,595	$110,832	$47,724	$32,435	$6,904	$1,498,023
1808-1	Buildings and Fixtures > 50 kV	$29,423	$29,423	$0	$29,423	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$909,337	$909,337	$0	$909,337	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$3,881,489	$3,881,489	$0	$3,881,489	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$425,481	$0	$425,481	$425,481	$90,791	$42,523	$22,531	$140,110	$83,987	$42,763	$1,819	$957	$425,481
1830-4	Poles, Towers and Fixtures - Primary	$6,159,699	$4,003,804	$2,155,895	$6,159,699	$1,657,384	$179,752	$5,734	$25,381	$1,418	$132	$238,505	$47,590	$2,155,895
1830-5	Poles, Towers and Fixtures - Secondary	$5,650,396	$3,672,758	$1,977,639	$5,650,396	$1,538,308	$166,838	$1,333	$5,587	$32	$1	$221,369	$44,171	$1,977,639
1835-4	Overhead Conductors and Devices - Primary	$4,468,209	$2,904,336	$1,563,873	$4,468,209	$1,202,256	$130,391	$4,159	$18,411	$1,029	$95	$173,010	$34,521	$1,563,873
1835-5	Overhead Conductors and Devices - Secondary	$4,142,994	$2,692,946	$1,450,048	$4,142,994	$1,127,921	$122,329	$977	$4,096	$24	$1	$162,313	$32,387	$1,450,048
1840-4	Underground Conduit - Primary	$25,461,719	$16,550,117	$8,911,602	$25,461,719	$6,850,958	$743,023	$23,700	$104,914	$5,861	$544	$985,884	$196,718	$8,911,602
1840-5	Underground Conduit - Secondary	$7,978,128	$5,185,783	$2,792,345	$7,978,128	$2,172,028	$235,568	$1,882	$7,888	$45	$1	$312,565	$62,367	$2,792,345
1845-4	Underground Conductors and Devices - Primary	$10,821,565	$7,034,017	$3,787,548	$10,821,565	$2,911,747	$315,795	$10,073	$44,590	$2,491	$231	$419,013	$83,608	$3,787,548
1845-5	Underground Conductors and Devices - Secondary	$3,885,749	$2,525,737	$1,360,012	$3,885,749	$1,057,887	$114,734	$917	$3,842	$22	$1	$152,235	$30,376	$1,360,012
1850	Line Transformers	$18,815,588	$13,170,912	$5,644,676	$18,815,588	$4,354,514	$472,271	$12,578	$52,715	$908	$21	$626,634	$125,035	$5,644,676
1855	Services	$11,574,589	$0	$11,574,589	$11,574,589	$8,067,397	$1,749,905	$69,911	$292,988	$1,682	$125	$1,160,935	$231,647	$11,574,589
1860	Meters	$15,082,855	$0	$15,082,855	$15,082,855	$10,191,370	$1,253,641	$355,039	$2,793,316	$441,103	$48,387	$0	$0	$15,082,855
	Sub - Total	**$120,994,961**	**$62,770,376**	**$58,224,585**	**$120,994,961**	**$41,944,984**	**$5,775,062**	**$572,651**	**$3,759,433**	**$649,433**	**$140,025**	**$4,486,717**	**$896,281**	**$58,224,585**
General Plant														
1908	Buildings and Fixtures	$2,352,037												
1915	Office Furniture and Equipment	$727,474												
1920	Computer Equipment - Hardware	$3,205,553												
1925	Computer Software	$14,468,034												
1930	Transportation Equipment	$4,352,125												
1935	Stores Equipment	$7,851												
1940	Tools, Shop and Garage Equipment	$1,374,300												
1945	Measurement and Testing Equipment	$94,355												
1955	Communication Equipment	$1,167,482												
1970	Load Management Controls - Customer Premises	$293,937												
1975	Load Management Controls - Utility Premises	$41,365												
1980	System Supervisory Equipment	$2,084,497												
2005	Property Under Capital Leases	$243,333												
	Sub - Total	**$30,412,343**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$151,407,304	$62,770,376	$58,224,585	$120,994,961	$41,944,984	$5,775,062	$572,651	$3,759,433	$649,433	$140,025	$4,486,717	$896,281	$58,224,585

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$28,604	$28,604	$0	$28,604	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$28,604**	**$28,604**	**$0**	**$28,604**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$500,661**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$529,265	$28,604	$0	$28,604	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

	Customer Allocation 1	2	3	4	5	6	7	9	Sub -total

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1815	Transformer Station Equipment - Normally Primary above 50 kV	$191,700	$191,700	$0	$191,700	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$191,700**	**$191,700**	**$0**	**$191,700**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$191,700	$191,700	$0	$191,700	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%	48.23%	16.57%	4.26%	17.73%	7.40%	3.19%	2.17%	0.46%	100.00%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	21.34%	9.99%	5.30%	32.93%	19.74%	10.05%	0.43%	0.22%	100.00%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	76.88%	8.34%	0.27%	1.18%	0.07%	0.01%	11.06%	2.21%	100.00%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	77.79%	8.44%	0.07%	0.28%	0.00%	0.00%	11.19%	2.23%	100.00%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	76.88%	8.34%	0.27%	1.18%	0.07%	0.01%	11.06%	2.21%	100.00%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	77.79%	8.44%	0.07%	0.28%	0.00%	0.00%	11.19%	2.23%	100.00%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
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Sheet O7 Amortization Output Worksheet

1840-4	Underground Conduit - Primary	100%	65%	35%	100%	76.88%	8.34%	0.27%	1.18%	0.07%	0.01%	11.06%	2.21%	100.00%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	77.79%	8.44%	0.07%	0.28%	0.00%	0.00%	11.19%	2.23%	100.00%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	76.88%	8.34%	0.27%	1.18%	0.07%	0.01%	11.06%	2.21%	100.00%
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	77.79%	8.44%	0.07%	0.28%	0.00%	0.00%	11.19%	2.23%	100.00%
1850	Line Transformers	100%	70%	30%	100%	77.14%	8.37%	0.22%	0.93%	0.02%	0.00%	11.10%	2.22%	100.00%
1855	Services	100%	0%	100%	100%	69.70%	15.12%	0.60%	2.53%	0.01%	0.00%	10.03%	2.00%	100.00%
1860	Meters	100%	0%	100%	100%	67.57%	8.31%	2.35%	18.52%	2.92%	0.32%	0.00%	0.00%	100.00%
General Plant														
1905	Land	100%												
1906	Land Rights	100%												
1908	Buildings and Fixtures	100%												
1910	Leasehold Improvements	100%												
1915	Office Furniture and Equipment	100%												
1920	Computer Equipment - Hardware	100%												
1925	Computer Software	100%												
1930	Transportation Equipment	100%												
1935	Stores Equipment	100%												
1940	Tools, Shop and Garage Equipment	100%												
1945	Measurement and Testing Equipment	100%												
1950	Power Operated Equipment	100%												
1955	Communication Equipment	100%												
1960	Miscellaneous Equipment	100%												
1970	Load Management Controls - Customer Premises	100%												
1975	Load Management Controls - Utility Premises	100%												
1980	System Supervisory Equipment	100%												
1990	Other Tangible Property	100%												
2005	Property Under Capital Leases	100%												
2010	Electric Plant Purchased or Sold	100%												

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Sheet O7 Amortization Output Worksheet

Ontario

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	($5,172,777)	($3,362,305)	($1,810,472)	($5,172,777)									
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0									
1835	Overhead Conductors and Devices	$0	$0	$0	$0									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0									
1835-4	Overhead Conductors and Devices - Primary	($4,998,228)	($3,248,848)	($1,749,380)	($4,998,228)									
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0									
1840	Underground Conduit	$0	$0	$0	$0									
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0									
1840-4	Underground Conduit - Primary	($29,937,354)	($19,459,280)	($10,478,074)	($29,937,354)									
1840-5	Underground Conduit - Secondary	($44,906,032)	($29,188,921)	($15,717,111)	($44,906,032)									
1845	Underground Conductors and Devices	$0	$0	$0	$0									
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0									
1845-4	Underground Conductors and Devices - Primary	($35,240,045)	($22,906,029)	($12,334,016)	($35,240,045)									
1845-5	Underground Conductors and Devices - Secondary	($11,746,682)	($7,635,343)	($4,111,339)	($11,746,682)									
1850	Line Transformers	($82,833,694)	($57,983,586)	($24,850,108)	($82,833,694)									
1855	Services	($2,989,970)	$0	($2,989,970)	($2,989,970)									
1860	Meters	($2,049,477)	$0	($2,049,477)	($2,049,477)									
	Sub - Total	**($219,874,258)**	**($143,784,312)**	**($76,089,946)**	**($219,874,258)**									
General Plant														
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 1995	($219,874,258)	($143,784,312)	($76,089,946)	($219,874,258)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Capital Contribution

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,057,756	$687,541	$370,214	$1,057,756									
1835-4	Overhead Conductors and Devices - Primary	$1,015,698	$660,203	$355,494	$1,015,698									
1840-4	Underground Conduit - Primary	$4,132,088	$2,685,857	$1,446,231	$4,132,088									
1840-5	Underground Conduit - Secondary	$6,198,132	$4,028,786	$2,169,346	$6,198,132									
1845-4	Underground Conductors and Devices - Primary	$5,967,607	$3,878,944	$2,088,662	$5,967,607									
1845-5	Underground Conductors and Devices - Secondary	$1,989,202	$1,292,981	$696,221	$1,989,202									
1850	Line Transformers	$9,315,694	$6,520,986	$2,794,708	$9,315,694									
1855	Services	$382,127	$0	$382,127	$382,127									
1860	Meters	$491,028	$0	$491,028	$491,028									
	Sub - Total	**$30,549,331**	**$19,755,299**	**$10,794,031**	**$30,549,331**									
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 2105 CC	$30,549,331	$19,755,299	$10,794,031	$30,549,331	$0	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Fixed Assets Only

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
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Sheet O7 Amortization Output Worksheet

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($2,523,488)	$0	($2,523,488)	($2,523,488)									
1808-1	Buildings and Fixtures > 50 kV	($499,244)	($499,244)	$0	($499,244)									
1808-2	Buildings and Fixtures < 50 KV	($15,336,338)	($15,336,338)	$0	($15,336,338)									
1815	Transformer Station Equipment - Normally Primary above 50 kV	($2,829,051)	($2,829,051)	$0	($2,829,051)									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($74,604,025)	($74,604,025)	$0	($74,604,025)									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($479,132)	$0	($479,132)	($479,132)									
1830-4	Poles, Towers and Fixtures - Primary	($74,103,283)	($48,167,134)	($25,936,149)	($74,103,283)									
1830-5	Poles, Towers and Fixtures - Secondary	($65,767,014)	($42,748,559)	($23,018,455)	($65,767,014)									
1835-4	Overhead Conductors and Devices - Primary	($80,839,270)	($52,545,525)	($28,293,744)	($80,839,270)									
1835-5	Overhead Conductors and Devices - Secondary	($71,745,233)	($46,634,402)	($25,110,832)	($71,745,233)									
1840-4	Underground Conduit - Primary	($349,571,990)	($227,221,793)	($122,350,196)	($349,571,990)									
1840-5	Underground Conduit - Secondary	($124,488,208)	($80,917,335)	($43,570,873)	($124,488,208)									
1845-4	Underground Conductors and Devices - Primary	($153,456,452)	($99,746,694)	($53,709,758)	($153,456,452)									
1845-5	Underground Conductors and Devices - Secondary	($54,648,311)	($35,521,402)	($19,126,909)	($54,648,311)									
1850	Line Transformers	($300,902,650)	($210,631,855)	($90,270,795)	($300,902,650)									
1855	Services	($162,072,047)	$0	($162,072,047)	($162,072,047)									
1860	Meters	($92,274,863)	$0	($92,274,863)	($92,274,863)									
	Sub - Total	**($1,626,140,598)**	**($937,403,357)**	**($688,737,241)**	**($1,626,140,598)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1908	Buildings and Fixtures	($30,903,334)				($15,151,212)	($4,300,855)	($1,222,721)	($5,617,184)	($2,250,738)	($942,625)	($1,176,368)	($241,630)	($30,903,334)
1915	Office Furniture and Equipment	($18,242,930)				($8,944,100)	($2,538,891)	($721,799)	($3,315,950)	($1,328,661)	($556,453)	($694,436)	($142,640)	($18,242,930)
1920	Computer Equipment - Hardware	($38,982,514)				($19,112,254)	($5,425,244)	($1,542,381)	($7,085,707)	($2,839,158)	($1,189,059)	($1,483,910)	($304,800)	($38,982,514)
1925	Computer Software	($95,041,935)				($46,596,933)	($13,227,102)	($3,760,427)	($17,275,420)	($6,922,053)	($2,899,005)	($3,617,871)	($743,123)	($95,041,935)
1930	Transportation Equipment	($49,780,353)				($24,406,192)	($6,927,993)	($1,969,609)	($9,048,390)	($3,625,581)	($1,518,419)	($1,894,942)	($389,227)	($49,780,353)
1935	Stores Equipment	($5,456,647)				($2,675,272)	($759,408)	($215,898)	($991,834)	($397,416)	($166,441)	($207,713)	($42,665)	($5,456,647)
1940	Tools, Shop and Garage Equipment	($21,741,205)				($10,659,226)	($3,025,750)	($860,212)	($3,951,818)	($1,583,446)	($663,158)	($827,602)	($169,992)	($21,741,205)
1945	Measurement and Testing Equipment	($4,028,728)				($1,975,195)	($560,683)	($159,401)	($732,287)	($293,419)	($122,886)	($153,358)	($31,500)	($4,028,728)
1955	Communication Equipment	($22,354,831)				($10,960,073)	($3,111,149)	($884,491)	($4,063,355)	($1,628,137)	($681,876)	($850,960)	($174,790)	($22,354,831)
1960	Miscellaneous Equipment	($104,582)				($51,274)	($14,555)	($4,138)	($19,009)	($7,617)	($3,190)	($3,981)	($818)	($104,582)
1970	Load Management Controls - Customer Premises	($4,114,792)				($2,017,390)	($572,661)	($162,806)	($747,930)	($299,687)	($125,511)	($156,634)	($32,173)	($4,114,792)
1975	Load Management Controls - Utility Premises	($525,613)				($257,696)	($73,150)	($20,796)	($95,539)	($38,281)	($16,032)	($20,008)	($4,110)	($525,613)
1980	System Supervisory Equipment	($30,486,551)				($14,946,873)	($4,242,850)	($1,206,230)	($5,541,427)	($2,220,383)	($929,912)	($1,160,503)	($238,371)	($30,486,551)
2005	Property Under Capital Leases	($571,810)				($280,346)	($79,579)	($22,624)	($103,936)	($41,646)	($17,442)	($21,767)	($4,471)	($571,810)
	Sub - Total	**($322,335,822)**				($158,034,035)	($44,859,870)	($12,753,533)	($58,589,786)	($23,476,224)	($9,832,009)	($12,270,052)	($2,520,311)	($322,335,822)
	TOTAL - 2105 FA	($1,948,476,420)	($937,403,357)	($688,737,241)	($1,626,140,598)	($158,034,035)	($44,859,870)	($12,753,533)	($58,589,786)	($23,476,224)	($9,832,009)	($12,270,052)	($2,520,311)	($322,335,822)

Accumulated Depreciation - 2120

						A & G Allocation								
						1	2	3	4	5	6	7	9	
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	($212,548)	($212,548)	$0	($212,548)									
1815	Transformer Station Equipment - Normally Primary above 50 kV	($374,993)	($374,993)	$0	($374,993)									
	Sub - Total	**($587,541)**	**($587,541)**	**$0**	**($587,541)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	($2,104,231)				($1,031,657)	($292,848)	($83,256)	($382,478)	($153,254)	($64,184)	($80,100)	($16,453)	($2,104,231)
1910	Leasehold Improvements	($2,702,274)				($1,324,864)	($376,079)	($106,918)	($491,182)	($196,811)	($82,426)	($102,865)	($21,129)	($2,702,274)
	Sub - Total	**($4,806,505)**				**($2,356,522)**	**($668,927)**	**($190,174)**	**($873,661)**	**($350,065)**	**($146,610)**	**($182,965)**	**($37,582)**	**($4,806,505)**
	TOTAL - 2120	($5,394,046)	($587,541)	$0	($587,541)	($2,356,522)	($668,927)	($190,174)	($873,661)	($350,065)	($146,610)	($182,965)	($37,582)	($4,806,505)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

		A & G Allocation							
		1	2	3	4	5	6	7	9	Sub -total

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	$1,498,023	$0	$1,498,023	$1,498,023									
1808-1	Buildings and Fixtures > 50 kV	$29,423	$29,423	$0	$29,423									
1808-2	Buildings and Fixtures < 50 KV	$909,337	$909,337	$0	$909,337									
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$3,881,489	$3,881,489	$0	$3,881,489									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$425,481	$0	$425,481	$425,481									
1830-4	Poles, Towers and Fixtures - Primary	$6,159,699	$4,003,804	$2,155,895	$6,159,699									
1830-5	Poles, Towers and Fixtures - Secondary	$5,650,396	$3,672,758	$1,977,639	$5,650,396									
1835-4	Overhead Conductors and Devices - Primary	$4,468,209	$2,904,336	$1,563,873	$4,468,209									
1835-5	Overhead Conductors and Devices - Secondary	$4,142,994	$2,692,946	$1,450,048	$4,142,994									
1840-4	Underground Conduit - Primary	$25,461,719	$16,550,117	$8,911,602	$25,461,719									
1840-5	Underground Conduit - Secondary	$7,978,128	$5,185,783	$2,792,345	$7,978,128									
1845-4	Underground Conductors and Devices - Primary	$10,821,565	$7,034,017	$3,787,548	$10,821,565									
1845-5	Underground Conductors and Devices - Secondary	$3,885,749	$2,525,737	$1,360,012	$3,885,749									
1850	Line Transformers	$18,815,588	$13,170,912	$5,644,676	$18,815,588									
1855	Services	$11,574,589	$0	$11,574,589	$11,574,589									
1860	Meters	$15,082,855	$0	$15,082,855	$15,082,855									
	Sub - Total	**$120,994,961**	**$62,770,376**	**$58,224,585**	**$120,994,961**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1908	Buildings and Fixtures	$2,352,037				$1,153,151	$327,336	$93,061	$427,521	$171,303	$71,743	$89,533	$18,390	$2,352,037
1915	Office Furniture and Equipment	$727,474				$356,664	$101,243	$28,783	$132,230	$52,983	$22,190	$27,692	$5,688	$727,474
1920	Computer Equipment - Hardware	$3,205,553				$1,571,611	$446,121	$126,831	$582,661	$233,465	$97,777	$122,023	$25,064	$3,205,553
1925	Computer Software	$14,468,034				$7,093,353	$2,013,534	$572,442	$2,629,801	$1,053,730	$441,309	$550,741	$113,124	$14,468,034
1930	Transportation Equipment	$4,352,125				$2,133,749	$605,691	$172,196	$791,070	$316,972	$132,750	$165,668	$34,029	$4,352,125
1935	Stores Equipment	$7,851				$3,849	$1,093	$311	$1,427	$572	$239	$299	$61	$7,851
1940	Tools, Shop and Garage Equipment	$1,374,300				$673,789	$191,263	$54,376	$249,801	$100,092	$41,919	$52,314	$10,746	$1,374,300
1945	Measurement and Testing Equipment	$94,355				$46,260	$13,132	$3,733	$17,151	$6,872	$2,878	$3,592	$738	$94,355
1955	Communication Equipment	$1,167,482				$572,390	$162,480	$46,193	$212,209	$85,030	$35,611	$44,441	$9,128	$1,167,482
1970	Load Management Controls - Customer Premises	$293,937				$144,111	$40,908	$11,630	$53,428	$21,408	$8,966	$11,189	$2,298	$293,937
1975	Load Management Controls - Utility Premises	$41,365				$20,280	$5,757	$1,637	$7,519	$3,013	$1,262	$1,575	$323	$41,365
1980	System Supervisory Equipment	$2,084,497				$1,021,982	$290,102	$82,475	$378,891	$151,817	$63,582	$79,349	$16,298	$2,084,497
2005	Property Under Capital Leases	$243,333				$119,301	$33,865	$9,628	$44,230	$17,722	$7,422	$9,263	$1,903	$243,333
	Sub - Total	**$30,412,343**				$14,910,491	$4,232,523	$1,203,294	$5,527,939	$2,214,979	$927,649	$1,157,678	$237,791	$30,412,343
	TOTAL - 5705	$151,407,304	$62,770,376	$58,224,585	$120,994,961	$14,910,491	$4,232,523	$1,203,294	$5,527,939	$2,214,979	$927,649	$1,157,678	$237,791	$30,412,343

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$28,604	$28,604	$0	$28,604									
	Sub - Total	**$28,604**	**$28,604**	**$0**	**$28,604**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$500,661**				$245,463	$69,678	$19,809	$91,003	$36,464	$15,271	$19,058	$3,915	$500,661
	TOTAL - 5710	$529,265	$28,604	$0	$28,604	$245,463	$69,678	$19,809	$91,003	$36,464	$15,271	$19,058	$3,915	$500,661

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

	A & G Allocation								
	1	2	3	4	5	6	7	9	Sub -total

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Sheet O7 Amortization Output Worksheet

Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1815	Transformer Station Equipment - Normally Primary above 50 kV	$191,700	$191,700	$0	$191,700									
	Sub - Total	**$191,700**	**$191,700**	**$0**	**$191,700**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$191,700	$191,700	$0	$191,700	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						A & G Allocation								
						1	**2**	**3**	**4**	**5**	**6**	**7**	**9**	**Sub -total**
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						A & G Allocation								
						1	**2**	**3**	**4**	**5**	**6**	**7**	**9**	**Sub -total**
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%									
1805	Land													
1805-1	Land Station >50 kV	100%	100%	0%	100%									
1805-2	Land Station <50 kV	100%	100%	0%	100%									
1806	Land Rights													
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%									
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%									
1808	Buildings and Fixtures													
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%									
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%									
1810	Leasehold Improvements													
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%									
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%									
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%									
1820	Distribution Station Equipment - Normally Primary below 50 kV													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%									
1825	Storage Battery Equipment													
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%									
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%									
1830	Poles, Towers and Fixtures													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%									
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%									
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%									
1835	Overhead Conductors and Devices													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%									
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%									
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%									
1840	Underground Conduit													

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
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Sheet O7 Amortization Output Worksheet

1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%									
1840-4	Underground Conduit - Primary	100%	65%	35%	100%									
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%									
1845	Underground Conductors and Devices													
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%									
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%									
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%									
1850	Line Transformers	100%	70%	30%	100%									
1855	Services	100%	0%	100%	100%									
1860	Meters	100%	0%	100%	100%									
General Plant														
1905	Land	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1906	Land Rights	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1908	Buildings and Fixtures	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1910	Leasehold Improvements	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1915	Office Furniture and Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1920	Computer Equipment - Hardware	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1925	Computer Software	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1930	Transportation Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1935	Stores Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1940	Tools, Shop and Garage Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1945	Measurement and Testing Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1950	Power Operated Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1955	Communication Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1960	Miscellaneous Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1970	Load Management Controls - Customer Premises	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1975	Load Management Controls - Utility Premises	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1980	System Supervisory Equipment	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
1990	Other Tangible Property	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
2005	Property Under Capital Leases	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%
2010	Electric Plant Purchased or Sold	100%				49%	14%	4%	18%	7%	3%	4%	1%	100%

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Ontario

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Total
1830-4	Poles, Towers and Fixtures - Primary	($5,369,372)	($3,490,091)	($1,879,280)	($5,369,372)	($851,928)	($412,414)	($136,499)	($1,133,397)	($644,140)	($309,123)	$0	($2,590)	($3,490,091)
1835-4	Overhead Conductors and Devices - Primary	($5,207,930)	($3,385,155)	($1,822,776)	($5,207,930)	($826,313)	($400,014)	($132,395)	($1,099,319)	($624,772)	($299,829)	$0	($2,512)	($3,385,155)
1840-4	Underground Conduit - Primary	($32,074,014)	($20,848,109)	($11,225,905)	($32,074,014)	($5,089,003)	($2,463,561)	($815,381)	($6,770,365)	($3,847,777)	($1,846,552)	$0	($15,469)	($20,848,109)
1840-5	Underground Conduit - Secondary	($48,111,021)	($31,272,164)	($16,838,857)	($48,111,021)	($16,785,320)	($8,125,690)	($674,588)	($5,326,315)	($309,229)	$0	$0	($51,022)	($31,272,164)
1845-4	Underground Conductors and Devices - Primary	($38,111,298)	($24,772,344)	($13,338,954)	($38,111,298)	($6,046,905)	($2,927,277)	($968,860)	($8,044,750)	($4,572,044)	($2,194,128)	$0	($18,381)	($24,772,344)
1845-5	Underground Conductors and Devices - Secondary	($12,703,766)	($8,257,448)	($4,446,318)	($12,703,766)	($4,432,182)	($2,145,597)	($178,126)	($1,406,419)	($81,652)	$0	$0	($13,472)	($8,257,448)
1850	Line Transformers	($96,975,723)	($67,883,006)	($29,092,717)	($96,975,723)	($23,564,691)	($11,407,550)	($3,156,815)	($24,925,145)	($4,341,229)	($415,947)	$0	($71,629)	($67,883,006)
1855	Services	($3,094,989)	$0	($3,094,989)	($3,094,989)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($2,049,476)	$0	($2,049,476)	($2,049,476)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($243,697,589)**	**($159,908,317)**	**($83,789,272)**	**($243,697,589)**	**($57,596,343)**	**($27,882,105)**	**($6,062,663)**	**($48,705,710)**	**($14,420,843)**	**($5,065,579)**	**$0**	**($175,074)**	**($159,908,317)**
General Plant														
	Sub - Total	$0												
	TOTAL - 1995	($243,697,589)	($159,908,317)	($83,789,272)	($243,697,589)	($57,596,343)	($27,882,105)	($6,062,663)	($48,705,710)	($14,420,843)	($5,065,579)	$0	($175,074)	($159,908,317)

Accumulated Depreciation - 2105 Capital Contribution

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,268,599	$824,589	$444,009	$1,268,599	$201,281	$97,439	$32,250	$267,783	$152,188	$73,035	$0	$612	$824,589
1835-4	Overhead Conductors and Devices - Primary	$1,219,821	$792,883	$426,937	$1,219,821	$193,542	$93,693	$31,010	$257,487	$146,336	$70,227	$0	$588	$792,883
1840-4	Underground Conduit - Primary	$5,095,125	$3,311,831	$1,783,294	$5,095,125	$808,415	$391,350	$129,527	$1,075,508	$611,240	$293,334	$0	$2,457	$3,311,831
1840-5	Underground Conduit - Secondary	$7,642,687	$4,967,747	$2,674,941	$7,642,687	$2,666,436	$1,290,808	$107,162	$846,113	$49,123	$0	$0	$8,105	$4,967,747
1845-4	Underground Conductors and Devices - Primary	$7,383,423	$4,799,225	$2,584,198	$7,383,423	$1,171,486	$567,111	$187,700	$1,558,535	$885,757	$425,075	$0	$3,561	$4,799,225
1845-5	Underground Conductors and Devices - Secondary	$2,461,141	$1,599,742	$861,399	$2,461,141	$858,661	$415,673	$34,509	$272,470	$15,819	$0	$0	$2,610	$1,599,742
1850	Line Transformers	$12,714,489	$8,900,142	$3,814,347	$12,714,489	$3,089,567	$1,495,644	$413,890	$3,267,936	$569,179	$54,535	$0	$9,391	$8,900,142
1855	Services	$503,826	$0	$503,826	$503,826	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$573,007	$0	$573,007	$573,007	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$38,862,117**	**$25,196,159**	**$13,665,957**	**$38,862,117**	**$8,989,388**	**$4,351,718**	**$936,049**	**$7,545,832**	**$2,429,641**	**$916,207**	**$0**	**$27,325**	**$25,196,159**
General Plant														
	Sub - Total	**$0**												
	TOTAL - 2105 CC	$38,862,117	$25,196,159	$13,665,957	$38,862,117	$8,989,388	$4,351,718	$936,049	$7,545,832	$2,429,641	$916,207	$0	$27,325	$25,196,159

Accumulated Depreciation - 2105 Fixed Assets Only

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($4,065,293)	$0	($4,065,293)	($4,065,293)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	($536,253)	($536,253)	$0	($536,253)	($143,062)	($56,263)	($15,153)	($176,533)	($96,299)	($45,922)	($2,063)	($958)	($536,253)
1808-2	Buildings and Fixtures < 50 KV	($16,269,659)	($16,269,659)	$0	($16,269,659)	($4,340,433)	($1,706,983)	($459,740)	($5,355,923)	($2,921,662)	($1,393,264)	($62,597)	($29,057)	($16,269,659)
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,038,768)	($3,038,768)	$0	($3,038,768)	($810,685)	($318,822)	($85,868)	($1,000,353)	($545,694)	($260,227)	($11,692)	($5,427)	($3,038,768)
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($78,603,869)	($78,603,869)	$0	($78,603,869)	($19,187,129)	($9,288,394)	($3,074,239)	($25,526,387)	($14,507,320)	($6,962,077)	$0	($58,323)	($78,603,869)
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($1,046,265)	$0	($1,046,265)	($1,046,265)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	($80,566,350)	($52,368,128)	($28,198,223)	($80,566,350)	($12,783,010)	($6,188,192)	($2,048,145)	($17,006,403)	($9,665,188)	($4,638,333)	$0	($38,856)	($52,368,128)
1830-5	Poles, Towers and Fixtures - Secondary	($71,503,016)	($46,476,960)	($25,026,056)	($71,503,016)	($24,946,488)	($12,076,471)	($1,002,578)	($7,916,015)	($459,579)	$0	$0	($75,829)	($46,476,960)

1835-4	Overhead Conductors and Devices - Primary	($85,544,691)	($55,604,049)	($29,940,642)	($85,544,691)	($13,572,895)	($6,570,571)	($2,174,704)	($18,057,260)	($10,262,418)	($4,924,944)	$0	($41,257)	($55,604,049)
1835-5	Overhead Conductors and Devices - Secondary	($75,921,317)	($49,348,856)	($26,572,461)	($75,921,317)	($26,487,977)	($12,822,698)	($1,064,529)	($8,405,160)	($487,977)	$0	$0	($80,515)	($49,348,856)
1840-4	Underground Conduit - Primary	($376,526,169)	($244,742,010)	($131,784,159)	($376,526,169)	($59,741,290)	($28,920,463)	($9,571,991)	($79,479,285)	($45,170,177)	($21,677,211)	$0	($181,594)	($244,742,010)
1840-5	Underground Conduit - Secondary	($134,087,025)	($87,156,566)	($46,930,459)	($134,087,025)	($46,781,248)	($22,646,571)	($1,880,098)	($14,844,617)	($861,832)	$0	$0	($142,200)	($87,156,566)
1845-4	Underground Conductors and Devices - Primary	($166,299,446)	($108,094,640)	($58,204,806)	($166,299,446)	($26,385,798)	($12,773,234)	($4,227,639)	($35,103,433)	($19,950,208)	($9,574,124)	$0	($80,204)	($108,094,640)
1845-5	Underground Conductors and Devices - Secondary	($59,221,908)	($38,494,240)	($20,727,668)	($59,221,908)	($20,661,766)	($10,002,259)	($830,379)	($6,556,388)	($380,643)	$0	$0	($62,805)	($38,494,240)
1850	Line Transformers	($323,623,629)	($226,536,540)	($97,087,089)	($323,623,629)	($78,639,175)	($38,068,836)	($10,534,802)	($83,179,228)	($14,487,381)	($1,388,081)	$0	($239,037)	($226,536,540)
1855	Services	($173,928,422)	$0	($173,928,422)	($173,928,422)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($106,639,986)	$0	($106,639,986)	($106,639,986)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($1,757,422,065)**	**($1,007,270,538)**	**($750,151,526)**	**($1,757,422,065)**	**($334,480,955)**	**($161,439,758)**	**($36,969,866)**	**($302,606,985)**	**($119,796,378)**	**($50,864,183)**	**($76,352)**	**($1,036,061)**	**($1,007,270,538)**
General Plant														
1908	Buildings and Fixtures	($31,417,268)												
1915	Office Furniture and Equipment	($18,928,059)												
1920	Computer Equipment - Hardware	($42,701,044)												
1925	Computer Software	($110,413,849)												
1930	Transportation Equipment	($54,348,215)												
1935	Stores Equipment	($5,464,460)												
1940	Tools, Shop and Garage Equipment	($23,016,421)												
1945	Measurement and Testing Equipment	($4,118,387)												
1955	Communication Equipment	($23,568,800)												
1960	Miscellaneous Equipment	($104,582)												
1970	Load Management Controls - Customer Premises	($4,386,268)												
1975	Load Management Controls - Utility Premises	($550,339)												
1980	System Supervisory Equipment	($32,574,748)												
2005	Property Under Capital Leases	($805,003)												
	Sub - Total	**($352,397,440)**												
	TOTAL - 2105 FA	($2,109,819,504)	($1,007,270,538)	($750,151,526)	($1,757,422,065)	($334,480,955)	($161,439,758)	($36,969,866)	($302,606,985)	($119,796,378)	($50,864,183)	($76,352)	($1,036,061)	($1,007,270,538)

Accumulated Depreciation - 2120

Account	Description	Accumulated Depreciation	Demand	Customer	Total	Demand Allocation 1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	Sub -total Sub -total
1806-2	Land Rights Station <50 kV	($241,703)	($241,703)	$0	($241,703)	($64,482)	($25,359)	($6,830)	($79,568)	($43,404)	($20,698)	($930)	($432)	($241,703)
1815	Transformer Station Equipment - Normally Primary above 50 kV	($726,693)	($726,693)	$0	($726,693)	($193,868)	($76,243)	($20,535)	($239,225)	($130,498)	($62,231)	($2,796)	($1,298)	($726,693)
	Sub - Total	**($968,396)**	**($968,396)**	**$0**	**($968,396)**	**($258,349)**	**($101,602)**	**($27,364)**	**($318,793)**	**($173,902)**	**($82,929)**	**($3,726)**	**($1,730)**	**($968,396)**
General Plant														
1906	Land Rights	($2,279,018)												
1910	Leasehold Improvements	($3,038,148)												
	Sub - Total	**($5,317,166)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 2120	($6,285,561)	($968,396)	$0	($968,396)	($258,349)	($101,602)	($27,364)	($318,793)	($173,902)	($82,929)	($3,726)	($1,730)	($968,396)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

Account	Description	Depreciation	Demand	Customer	Total	Demand Allocation 1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load	Sub -total Sub -total
1565	Conservation and Demand Management	$1,585,587	$0	$1,585,587	$1,585,587	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$29,412	$29,412	$0	$29,412	$7,846	$3,086	$831	$9,682	$5,282	$2,519	$113	$53	$29,412
1808-2	Buildings and Fixtures < 50 KV	$972,490	$972,490	$0	$972,490	$259,442	$102,032	$27,480	$320,141	$174,637	$83,280	$3,742	$1,737	$972,490
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717	$55,948	$22,003	$5,926	$69,038	$37,660	$17,959	$807	$375	$209,717
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$4,118,198	$4,118,198	$0	$4,118,198	$1,005,248	$486,636	$161,065	$1,337,373	$760,065	$364,756	$0	$3,056	$4,118,198
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$708,786	$0	$708,786	$708,786	$0	$0	$0	$0	$0	$0	$0	$0	$0

1830-4	Poles, Towers and Fixtures - Primary	$6,344,749	$4,124,087	$2,220,662	$6,344,749	$1,006,686	$487,332	$161,295	$1,339,286	$761,151	$365,277	$0	$3,060	$4,124,087
1830-5	Poles, Towers and Fixtures - Secondary	$5,821,609	$3,784,046	$2,037,563	$5,821,609	$2,031,085	$983,238	$81,628	$644,503	$37,418	$0	$0	$6,174	$3,784,046
1835-4	Overhead Conductors and Devices - Primary	$4,534,387	$2,947,352	$1,587,036	$4,534,387	$719,446	$348,280	$115,273	$957,144	$543,970	$261,052	$0	$2,187	$2,947,352
1835-5	Overhead Conductors and Devices - Secondary	$4,209,173	$2,735,962	$1,473,210	$4,209,173	$1,468,526	$710,906	$59,019	$465,993	$27,054	$0	$0	$4,464	$2,735,962
1840-4	Underground Conduit - Primary	$26,574,366	$17,273,338	$9,301,028	$26,574,366	$4,216,405	$2,041,141	$675,569	$5,609,468	$3,188,009	$1,529,929	$0	$12,816	$17,273,338
1840-5	Underground Conduit - Secondary	$8,276,596	$5,379,787	$2,896,809	$8,276,596	$2,887,598	$1,397,872	$116,050	$916,292	$53,197	$0	$0	$8,777	$5,379,787
1845-4	Underground Conductors and Devices - Primary	$12,031,214	$7,820,289	$4,210,925	$12,031,214	$1,908,925	$924,101	$305,856	$2,539,617	$1,443,332	$692,656	$0	$5,803	$7,820,289
1845-5	Underground Conductors and Devices - Secondary	$4,319,142	$2,807,442	$1,511,700	$4,319,142	$1,506,893	$729,480	$60,561	$478,167	$27,761	$0	$0	$4,580	$2,807,442
1850	Line Transformers	$19,828,777	$13,880,144	$5,948,633	$19,828,777	$4,818,309	$2,332,520	$645,479	$5,096,483	$887,658	$85,049	$0	$14,646	$13,880,144
1855	Services	$11,894,762	$0	$11,894,762	$11,894,762	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$13,483,431	$0	$13,483,431	$13,483,431	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$124,942,396**	**$66,082,264**	**$58,860,132**	**$124,942,396**	**$21,892,359**	**$10,568,626**	**$2,416,031**	**$19,783,189**	**$7,947,194**	**$3,402,477**	**$4,662**	**$67,727**	**$66,082,264**
General Plant														
1908	Buildings and Fixtures	$2,150,230												
1915	Office Furniture and Equipment	$642,785												
1920	Computer Equipment - Hardware	$4,231,507												
1925	Computer Software	$16,275,794												
1930	Transportation Equipment	$4,773,599												
1935	Stores Equipment	$7,777												
1940	Tools, Shop and Garage Equipment	$1,176,132												
1945	Measurement and Testing Equipment	$84,963												
1955	Communication Equipment	$1,260,455												
1970	Load Management Controls - Customer Premises	$249,016												
1975	Load Management Controls - Utility Premises	$8,087												
1980	System Supervisory Equipment	$2,091,897												
2005	Property Under Capital Leases	$233,052												
	Sub - Total	**$33,185,294**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$158,127,690	$66,082,264	$58,860,132	$124,942,396	$21,892,359	$10,568,626	$2,416,031	$19,783,189	$7,947,194	$3,402,477	$4,662	$67,727	$66,082,264

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$29,704	$29,704	$0	$29,704	$7,924	$3,116	$839	$9,778	$5,334	$2,544	$114	$53	$29,704
	Sub - Total	**$29,704**	**$29,704**	**$0**	**$29,704**	**$7,924**	**$3,116**	**$839**	**$9,778**	**$5,334**	**$2,544**	**$114**	**$53**	**$29,704**
General Plant														
1906	Land Rights	$174,787												
1910	Leasehold Improvements	$345,873												
	Sub - Total	**$520,660**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$550,364	$29,704	$0	$29,704	$7,924	$3,116	$839	$9,778	$5,334	$2,544	$114	$53	$29,704

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1815	Transformer Station Equipment - Normally Primary above 50 kV	$511,700	$511,700	$0	$511,700	$136,512	$53,687	$14,459	$168,450	$91,890	$43,820	$1,969	$914	$511,700
	Sub - Total	**$511,700**	**$511,700**	**$0**	**$511,700**	**$136,512**	**$53,687**	**$14,459**	**$168,450**	**$91,890**	**$43,820**	**$1,969**	**$914**	**$511,700**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0

	TOTAL - 5715	$511,700	$511,700	$0	$511,700	$136,512	$53,687	$14,459	$168,450	$91,890	$43,820	$1,969	$914	$511,700

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant														
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description		Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%	100.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%	100.00%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	53.67%	25.98%	2.16%	17.03%	0.99%	0.00%	0.00%	0.16%	100.00%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%	100.00%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	53.67%	25.98%	2.16%	17.03%	0.99%	0.00%	0.00%	0.16%	100.00%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1840-4	Underground Conduit - Primary	100%	65%	35%	100%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%	100.00%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	53.67%	25.98%	2.16%	17.03%	0.99%	0.00%	0.00%	0.16%	100.00%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%	100.00%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%	100.00%

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1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	53.67%	25.98%	2.16%	17.03%	0.99%	0.00%	0.00%	0.16%	100.00%
1850	Line Transformers	100%	70%	30%	100%	34.71%	16.80%	4.65%	36.72%	6.40%	0.61%	0.00%	0.11%	100.00%
1855	Services	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1860	Meters	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Plant														
1905	Land	100%												
1906	Land Rights	100%												
1908	Buildings and Fixtures	100%												
1910	Leasehold Improvements	100%												
1915	Office Furniture and Equipment	100%												
1920	Computer Equipment - Hardware	100%												
1925	Computer Software	100%												
1930	Transportation Equipment	100%												
1935	Stores Equipment	100%												
1940	Tools, Shop and Garage Equipment	100%												
1945	Measurement and Testing Equipment	100%												
1950	Power Operated Equipment	100%												
1955	Communication Equipment	100%												
1960	Miscellaneous Equipment	100%												
1970	Load Management Controls - Customer Premises	100%												
1975	Load Management Controls - Utility Premises	100%												
1980	System Supervisory Equipment	100%												
1990	Other Tangible Property	100%												
2005	Property Under Capital Leases	100%												
2010	Electric Plant Purchased or Sold	100%												

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Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	($5,369,372)	($3,490,091)	($1,879,280)	($5,369,372)	($1,468,243)	($152,340)	($2,426)	($24,009)	($1,221)	($112)	($202,302)	($28,629)	($1,879,280)
1835-4	Overhead Conductors and Devices - Primary	($5,207,930)	($3,385,155)	($1,822,776)	($5,207,930)	($1,424,097)	($147,759)	($2,353)	($23,287)	($1,184)	($108)	($196,219)	($27,768)	($1,822,776)
1840-4	Underground Conduit - Primary	($32,074,014)	($20,848,109)	($11,225,905)	($32,074,014)	($8,770,568)	($910,003)	($14,491)	($143,417)	($7,293)	($667)	($1,208,453)	($171,013)	($11,225,905)
1840-5	Underground Conduit - Secondary	($48,111,021)	($31,272,164)	($16,838,857)	($48,111,021)	($13,307,401)	($1,380,729)	($5,515)	($51,902)	($270)	($7)	($1,833,560)	($259,474)	($16,838,857)
1845-4	Underground Conductors and Devices - Primary	($38,111,298)	($24,772,344)	($13,338,954)	($38,111,298)	($10,421,450)	($1,081,293)	($17,219)	($170,412)	($8,666)	($792)	($1,435,919)	($203,203)	($13,338,954)
1845-5	Underground Conductors and Devices - Secondary	($12,703,766)	($8,257,448)	($4,446,318)	($12,703,766)	($3,513,833)	($364,583)	($1,456)	($13,705)	($71)	($2)	($484,154)	($68,514)	($4,446,318)
1850	Line Transformers	($96,975,723)	($67,883,006)	($29,092,717)	($96,975,723)	($22,806,557)	($2,366,328)	($31,507)	($296,503)	($4,621)	($106)	($3,142,402)	($444,693)	($29,092,717)
1855	Services	($3,094,989)	$0	($3,094,989)	($3,094,989)	($2,197,895)	($456,092)	($9,109)	($85,723)	($445)	($33)	($302,837)	($42,856)	($3,094,989)
1860	Meters	($2,049,476)	$0	($2,049,476)	($2,049,476)	($1,373,520)	($200,751)	($22,218)	($390,636)	($56,270)	($6,080)	$0	$0	($2,049,476)
	Sub - Total	**($243,697,589)**	**($159,908,317)**	**($83,789,272)**	**($243,697,589)**	**($65,283,564)**	**($7,059,878)**	**($106,294)**	**($1,199,593)**	**($80,042)**	**($7,906)**	**($8,805,846)**	**($1,246,150)**	**($83,789,272)**
General Plant														
	Sub - Total	$0												
	TOTAL - 1995	($243,697,589)	($159,908,317)	($83,789,272)	($243,697,589)	($65,283,564)	($7,059,878)	($106,294)	($1,199,593)	($80,042)	($7,906)	($8,805,846)	($1,246,150)	($83,789,272)

Accumulated Depreciation - 2105 Capital Contribution

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,268,599	$824,589	$444,009	$1,268,599	$346,895	$35,993	$573	$5,672	$288	$26	$47,797	$6,764	$444,009
1835-4	Overhead Conductors and Devices - Primary	$1,219,821	$792,883	$426,937	$1,219,821	$333,557	$34,609	$551	$5,454	$277	$25	$45,959	$6,504	$426,937
1840-4	Underground Conduit - Primary	$5,095,125	$3,311,831	$1,783,294	$5,095,125	$1,393,251	$144,559	$2,302	$22,783	$1,159	$106	$191,969	$27,166	$1,783,294
1840-5	Underground Conduit - Secondary	$7,642,687	$4,967,747	$2,674,941	$7,642,687	$2,113,950	$219,336	$876	$8,245	$43	$1	$291,271	$41,219	$2,674,941
1845-4	Underground Conductors and Devices - Primary	$7,383,423	$4,799,225	$2,584,198	$7,383,423	$2,018,981	$209,482	$3,336	$33,014	$1,679	$153	$278,185	$39,367	$2,584,198
1845-5	Underground Conductors and Devices - Secondary	$2,461,141	$1,599,742	$861,399	$2,461,141	$680,746	$70,632	$282	$2,655	$14	$0	$93,797	$13,274	$861,399
1850	Line Transformers	$12,714,489	$8,900,142	$3,814,347	$12,714,489	$2,990,168	$310,249	$4,131	$38,874	$606	$14	$412,000	$58,304	$3,814,347
1855	Services	$503,826	$0	$503,826	$503,826	$357,790	$74,246	$1,483	$13,955	$72	$5	$49,298	$6,976	$503,826
1860	Meters	$573,007	$0	$573,007	$573,007	$384,018	$56,127	$6,212	$109,217	$15,732	$1,700	$0	$0	$573,007
	Sub - Total	**$38,862,117**	**$25,196,159**	**$13,665,957**	**$38,862,117**	**$10,619,356**	**$1,155,233**	**$19,746**	**$239,870**	**$19,871**	**$2,032**	**$1,410,276**	**$199,574**	**$13,665,957**
General Plant														
	Sub - Total	**$0**												
	TOTAL - 2105 CC	$38,862,117	$25,196,159	$13,665,957	$38,862,117	$10,619,356	$1,155,233	$19,746	$239,870	$19,871	$2,032	$1,410,276	$199,574	$13,665,957

Accumulated Depreciation - 2105 Fixed Assets Only

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($4,065,293)	$0	($4,065,293)	($4,065,293)	($2,008,886)	($646,468)	($104,787)	($773,899)	($300,984)	($129,873)	($86,004)	($14,392)	($4,065,293)
1808-1	Buildings and Fixtures > 50 kV	($536,253)	($536,253)	$0	($536,253)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	($16,269,659)	($16,269,659)	$0	($16,269,659)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,038,768)	($3,038,768)	$0	($3,038,768)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($78,603,869)	($78,603,869)	$0	($78,603,869)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($1,046,265)	$0	($1,046,265)	($1,046,265)	($227,920)	($104,499)	($26,895)	($367,896)	($206,798)	($105,415)	($4,483)	($2,359)	($1,046,265)
1830-4	Poles, Towers and Fixtures - Primary	($80,566,350)	($52,368,128)	($28,198,223)	($80,566,350)	($22,030,689)	($2,285,827)	($36,401)	($360,247)	($18,320)	($1,675)	($3,035,499)	($429,565)	($28,198,223)
1830-5	Poles, Towers and Fixtures - Secondary	($71,503,016)	($46,476,960)	($25,026,056)	($71,503,016)	($19,777,574)	($2,052,051)	($8,197)	($77,137)	($401)	($10)	($2,725,053)	($385,633)	($25,026,056)

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1835-4	Overhead Conductors and Devices - Primary	($85,544,691)	($55,604,049)	($29,940,642)	($85,544,691)	($23,392,006)	($2,427,072)	($38,650)	($382,508)	($19,452)	($1,778)	($3,223,068)	($456,109)	($29,940,642)
1835-5	Overhead Conductors and Devices - Secondary	($75,921,317)	($49,348,856)	($26,572,461)	($75,921,317)	($20,999,666)	($2,178,851)	($8,703)	($81,904)	($425)	($10)	($2,893,439)	($409,462)	($26,572,461)
1840-4	Underground Conduit - Primary	($376,526,169)	($244,742,010)	($131,784,159)	($376,526,169)	($102,960,244)	($10,682,792)	($170,118)	($1,683,612)	($85,618)	($7,827)	($14,186,378)	($2,007,570)	($131,784,159)
1840-5	Underground Conduit - Secondary	($134,087,025)	($87,156,566)	($46,930,459)	($134,087,025)	($37,088,171)	($3,848,138)	($15,371)	($144,652)	($751)	($18)	($5,110,194)	($723,163)	($46,930,459)
1845-4	Underground Conductors and Devices - Primary	($166,299,446)	($108,094,640)	($58,204,806)	($166,299,446)	($45,474,214)	($4,718,244)	($75,136)	($743,597)	($37,815)	($3,457)	($6,265,665)	($886,679)	($58,204,806)
1845-5	Underground Conductors and Devices - Secondary	($59,221,908)	($38,494,240)	($20,727,668)	($59,221,908)	($16,380,647)	($1,699,598)	($6,789)	($63,888)	($332)	($8)	($2,257,007)	($319,398)	($20,727,668)
1850	Line Transformers	($323,623,629)	($226,536,540)	($97,087,089)	($323,623,629)	($76,109,160)	($7,896,818)	($105,142)	($989,478)	($15,421)	($354)	($10,486,701)	($1,484,014)	($97,087,089)
1855	Services	($173,928,422)	$0	($173,928,422)	($173,928,422)	($123,514,616)	($25,630,882)	($511,895)	($4,817,356)	($25,026)	($1,835)	($17,018,462)	($2,408,349)	($173,928,422)
1860	Meters	($106,639,986)	$0	($106,639,986)	($106,639,986)	($71,468,122)	($10,445,647)	($1,156,050)	($20,325,890)	($2,927,892)	($316,385)	$0	$0	($106,639,986)
	Sub - Total	**($1,757,422,065)**	**($1,007,270,538)**	**($750,151,526)**	**($1,757,422,065)**	**($561,431,915)**	**($74,616,889)**	**($2,264,133)**	**($30,812,064)**	**($3,639,235)**	**($568,646)**	**($67,291,952)**	**($9,526,692)**	**($750,151,526)**
General Plant														
1908	Buildings and Fixtures	($31,417,268)												
1915	Office Furniture and Equipment	($18,928,059)												
1920	Computer Equipment - Hardware	($42,701,044)												
1925	Computer Software	($110,413,849)												
1930	Transportation Equipment	($54,348,215)												
1935	Stores Equipment	($5,464,460)												
1940	Tools, Shop and Garage Equipment	($23,016,421)												
1945	Measurement and Testing Equipment	($4,118,387)												
1955	Communication Equipment	($23,568,800)												
1960	Miscellaneous Equipment	($104,582)												
1970	Load Management Controls - Customer Premises	($4,386,268)												
1975	Load Management Controls - Utility Premises	($550,339)												
1980	System Supervisory Equipment	($32,574,748)												
2005	Property Under Capital Leases	($805,003)												
	Sub - Total	**($352,397,440)**												
	TOTAL - 2105 FA	($2,109,819,504)	($1,007,270,538)	($750,151,526)	($1,757,422,065)	($561,431,915)	($74,616,889)	($2,264,133)	($30,812,064)	($3,639,235)	($568,646)	($67,291,952)	($9,526,692)	($750,151,526)

Accumulated Depreciation - 2120

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	($241,703)	($241,703)	$0	($241,703)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($726,693)	($726,693)	$0	($726,693)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($968,396)**	**($968,396)**	**$0**	**($968,396)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	($2,279,018)												
1910	Leasehold Improvements	($3,038,148)												
	Sub - Total	**($5,317,166)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 2120	($6,285,561)	($968,396)	$0	($968,396)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$1,585,587	$0	$1,585,587	$1,585,587	$783,526	$252,142	$40,870	$301,844	$117,393	$50,655	$33,544	$5,613	$1,585,587
1808-1	Buildings and Fixtures > 50 kV	$29,412	$29,412	$0	$29,412	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$972,490	$972,490	$0	$972,490	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$4,118,198	$4,118,198	$0	$4,118,198	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$708,786	$0	$708,786	$708,786	$154,403	$70,792	$18,220	$249,229	$140,094	$71,413	$3,037	$1,598	$708,786

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1830-4	Poles, Towers and Fixtures - Primary	$6,344,749	$4,124,087	$2,220,662	$6,344,749	$1,734,958	$180,013	$2,867	$28,370	$1,443	$132	$239,051	$33,829	$2,220,662
1830-5	Poles, Towers and Fixtures - Secondary	$5,821,609	$3,784,046	$2,037,563	$5,821,609	$1,610,244	$167,073	$667	$6,280	$33	$1	$221,867	$31,397	$2,037,563
1835-4	Overhead Conductors and Devices - Primary	$4,534,387	$2,947,352	$1,587,036	$4,534,387	$1,239,918	$128,650	$2,049	$20,275	$1,031	$94	$170,842	$24,177	$1,587,036
1835-5	Overhead Conductors and Devices - Secondary	$4,209,173	$2,735,962	$1,473,210	$4,209,173	$1,164,248	$120,798	$483	$4,541	$24	$1	$160,416	$22,701	$1,473,210
1840-4	Underground Conduit - Primary	$26,574,366	$17,273,338	$9,301,028	$26,574,366	$7,266,701	$753,967	$12,007	$118,826	$6,043	$552	$1,001,242	$141,690	$9,301,028
1840-5	Underground Conduit - Secondary	$8,276,596	$5,379,787	$2,896,809	$8,276,596	$2,289,288	$237,528	$949	$8,929	$46	$1	$315,430	$44,638	$2,896,809
1845-4	Underground Conductors and Devices - Primary	$12,031,214	$7,820,289	$4,210,925	$12,031,214	$3,289,909	$341,349	$5,436	$53,797	$2,736	$250	$453,300	$64,148	$4,210,925
1845-5	Underground Conductors and Devices - Secondary	$4,319,142	$2,807,442	$1,511,700	$4,319,142	$1,194,665	$123,954	$495	$4,659	$24	$1	$164,607	$23,294	$1,511,700
1850	Line Transformers	$19,828,777	$13,880,144	$5,948,633	$19,828,777	$4,663,292	$483,847	$6,442	$60,626	$945	$22	$642,532	$90,927	$5,948,633
1855	Services	$11,894,762	$0	$11,894,762	$11,894,762	$8,447,021	$1,752,866	$35,008	$329,453	$1,711	$125	$1,163,873	$164,704	$11,894,762
1860	Meters	$13,483,431	$0	$13,483,431	$13,483,431	$9,036,343	$1,320,735	$146,170	$2,569,981	$370,199	$40,003	$0	$0	$13,483,431
	Sub - Total	**$124,942,396**	**$66,082,264**	**$58,860,132**	**$124,942,396**	**$42,874,516**	**$5,933,716**	**$271,661**	**$3,756,811**	**$641,721**	**$163,249**	**$4,569,741**	**$648,717**	**$58,860,132**
General Plant														
1908	Buildings and Fixtures	$2,150,230												
1915	Office Furniture and Equipment	$642,785												
1920	Computer Equipment - Hardware	$4,231,507												
1925	Computer Software	$16,275,794												
1930	Transportation Equipment	$4,773,599												
1935	Stores Equipment	$7,777												
1940	Tools, Shop and Garage Equipment	$1,176,132												
1945	Measurement and Testing Equipment	$84,963												
1955	Communication Equipment	$1,260,455												
1970	Load Management Controls - Customer Premises	$249,016												
1975	Load Management Controls - Utility Premises	$8,087												
1980	System Supervisory Equipment	$2,091,897												
2005	Property Under Capital Leases	$233,052												
	Sub - Total	**$33,185,294**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$158,127,690	$66,082,264	$58,860,132	$124,942,396	$42,874,516	$5,933,716	$271,661	$3,756,811	$641,721	$163,249	$4,569,741	$648,717	$58,860,132

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$29,704	$29,704	$0	$29,704	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$29,704**	**$29,704**	**$0**	**$29,704**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	$174,787												
1910	Leasehold Improvements	$345,873												
	Sub - Total	**$520,660**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$550,364	$29,704	$0	$29,704	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1815	Transformer Station Equipment - Normally Primary above 50 kV	$511,700	$511,700	$0	$511,700	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$511,700**	**$511,700**	**$0**	**$511,700**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0

	TOTAL - 5715	$511,700	$511,700	$0	$511,700	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant														
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description		Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	100%	0%	100%	100%	49.42%	15.90%	2.58%	19.04%	7.40%	3.19%	2.12%	0.35%	100.00%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	21.78%	9.99%	2.57%	35.16%	19.77%	10.08%	0.43%	0.23%	100.00%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	78.13%	8.11%	0.13%	1.28%	0.06%	0.01%	10.76%	1.52%	100.00%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	79.03%	8.20%	0.03%	0.31%	0.00%	0.00%	10.89%	1.54%	100.00%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	78.13%	8.11%	0.13%	1.28%	0.06%	0.01%	10.76%	1.52%	100.00%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	79.03%	8.20%	0.03%	0.31%	0.00%	0.00%	10.89%	1.54%	100.00%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-4	Underground Conduit - Primary	100%	65%	35%	100%	78.13%	8.11%	0.13%	1.28%	0.06%	0.01%	10.76%	1.52%	100.00%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	79.03%	8.20%	0.03%	0.31%	0.00%	0.00%	10.89%	1.54%	100.00%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	78.13%	8.11%	0.13%	1.28%	0.06%	0.01%	10.76%	1.52%	100.00%

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Sheet O7 Amortization Output Worksheet

1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	79.03%	8.20%	0.03%	0.31%	0.00%	0.00%	10.89%	1.54%	100.00%
1850	Line Transformers	100%	70%	30%	100%	78.39%	8.13%	0.11%	1.02%	0.02%	0.00%	10.80%	1.53%	100.00%
1855	Services	100%	0%	100%	100%	71.01%	14.74%	0.29%	2.77%	0.01%	0.00%	9.78%	1.38%	100.00%
1860	Meters	100%	0%	100%	100%	67.02%	9.80%	1.08%	19.06%	2.75%	0.30%	0.00%	0.00%	100.00%
General Plant														
1905	Land	100%												
1906	Land Rights	100%												
1908	Buildings and Fixtures	100%												
1910	Leasehold Improvements	100%												
1915	Office Furniture and Equipment	100%												
1920	Computer Equipment - Hardware	100%												
1925	Computer Software	100%												
1930	Transportation Equipment	100%												
1935	Stores Equipment	100%												
1940	Tools, Shop and Garage Equipment	100%												
1945	Measurement and Testing Equipment	100%												
1950	Power Operated Equipment	100%												
1955	Communication Equipment	100%												
1960	Miscellaneous Equipment	100%												
1970	Load Management Controls - Customer Premises	100%												
1975	Load Management Controls - Utility Premises	100%												
1980	System Supervisory Equipment	100%												
1990	Other Tangible Property	100%												
2005	Property Under Capital Leases	100%												
2010	Electric Plant Purchased or Sold	100%												

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Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	($5,369,372)	($3,490,091)	($1,879,280)	($5,369,372)									
1835-4	Overhead Conductors and Devices - Primary	($5,207,930)	($3,385,155)	($1,822,776)	($5,207,930)									
1840-4	Underground Conduit - Primary	($32,074,014)	($20,848,109)	($11,225,905)	($32,074,014)									
1840-5	Underground Conduit - Secondary	($48,111,021)	($31,272,164)	($16,838,857)	($48,111,021)									
1845-4	Underground Conductors and Devices - Primary	($38,111,298)	($24,772,344)	($13,338,954)	($38,111,298)									
1845-5	Underground Conductors and Devices - Secondary	($12,703,766)	($8,257,448)	($4,446,318)	($12,703,766)									
1850	Line Transformers	($96,975,723)	($67,883,006)	($29,092,717)	($96,975,723)									
1855	Services	($3,094,989)	$0	($3,094,989)	($3,094,989)									
1860	Meters	($2,049,476)	$0	($2,049,476)	($2,049,476)									
	Sub - Total	**($243,697,589)**	**($159,908,317)**	**($83,789,272)**	**($243,697,589)**									
General Plant														
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 1995	($243,697,589)	($159,908,317)	($83,789,272)	($243,697,589)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Capital Contribution

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,268,599	$824,589	$444,009	$1,268,599									
1835-4	Overhead Conductors and Devices - Primary	$1,219,821	$792,883	$426,937	$1,219,821									
1840-4	Underground Conduit - Primary	$5,095,125	$3,311,831	$1,783,294	$5,095,125									
1840-5	Underground Conduit - Secondary	$7,642,687	$4,967,747	$2,674,941	$7,642,687									
1845-4	Underground Conductors and Devices - Primary	$7,383,423	$4,799,225	$2,584,198	$7,383,423									
1845-5	Underground Conductors and Devices - Secondary	$2,461,141	$1,599,742	$861,399	$2,461,141									
1850	Line Transformers	$12,714,489	$8,900,142	$3,814,347	$12,714,489									
1855	Services	$503,826	$0	$503,826	$503,826									
1860	Meters	$573,007	$0	$573,007	$573,007									
	Sub - Total	**$38,862,117**	**$25,196,159**	**$13,665,957**	**$38,862,117**									
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 2105 CC	$38,862,117	$25,196,159	$13,665,957	$38,862,117	$0	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Fixed Assets Only

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($4,065,293)	$0	($4,065,293)	($4,065,293)									
1808-1	Buildings and Fixtures > 50 kV	($536,253)	($536,253)	$0	($536,253)									
1808-2	Buildings and Fixtures < 50 KV	($16,269,659)	($16,269,659)	$0	($16,269,659)									
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,038,768)	($3,038,768)	$0	($3,038,768)									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($78,603,869)	($78,603,869)	$0	($78,603,869)									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($1,046,265)	$0	($1,046,265)	($1,046,265)									
1830-4	Poles, Towers and Fixtures - Primary	($80,566,350)	($52,368,128)	($28,198,223)	($80,566,350)									
1830-5	Poles, Towers and Fixtures - Secondary	($71,503,016)	($46,476,960)	($25,026,056)	($71,503,016)									

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1835-4	Overhead Conductors and Devices - Primary	($85,544,691)	($55,604,049)	($29,940,642)	($85,544,691)									
1835-5	Overhead Conductors and Devices - Secondary	($75,921,317)	($49,348,856)	($26,572,461)	($75,921,317)									
1840-4	Underground Conduit - Primary	($376,526,169)	($244,742,010)	($131,784,159)	($376,526,169)									
1840-5	Underground Conduit - Secondary	($134,087,025)	($87,156,566)	($46,930,459)	($134,087,025)									
1845-4	Underground Conductors and Devices - Primary	($166,299,446)	($108,094,640)	($58,204,806)	($166,299,446)									
1845-5	Underground Conductors and Devices - Secondary	($59,221,908)	($38,494,240)	($20,727,668)	($59,221,908)									
1850	Line Transformers	($323,623,629)	($226,536,540)	($97,087,089)	($323,623,629)									
1855	Services	($173,928,422)	$0	($173,928,422)	($173,928,422)									
1860	Meters	($106,639,986)	$0	($106,639,986)	($106,639,986)									
	Sub - Total	**($1,757,422,065)**	**($1,007,270,538)**	**($750,151,526)**	**($1,757,422,065)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1908	Buildings and Fixtures	($31,417,268)				($15,851,152)	($4,140,091)	($706,044)	($6,193,557)	($2,293,788)	($954,426)	($1,103,409)	($174,799)	($31,417,268)
1915	Office Furniture and Equipment	($18,928,059)				($9,549,893)	($2,494,294)	($425,372)	($3,731,452)	($1,381,946)	($575,016)	($664,774)	($105,312)	($18,928,059)
1920	Computer Equipment - Hardware	($42,701,044)				($21,544,227)	($5,627,040)	($959,625)	($8,418,026)	($3,117,622)	($1,297,216)	($1,499,708)	($237,580)	($42,701,044)
1925	Computer Software	($110,413,849)				($55,707,796)	($14,550,069)	($2,481,343)	($21,766,836)	($8,061,363)	($3,354,265)	($3,877,856)	($614,321)	($110,413,849)
1930	Transportation Equipment	($54,348,215)				($27,420,648)	($7,161,876)	($1,221,373)	($10,714,133)	($3,967,987)	($1,651,046)	($1,908,769)	($302,383)	($54,348,215)
1935	Stores Equipment	($5,464,460)				($2,757,018)	($720,093)	($122,803)	($1,077,256)	($398,963)	($166,005)	($191,918)	($30,403)	($5,464,460)
1940	Tools, Shop and Garage Equipment	($23,016,421)				($11,612,620)	($3,033,048)	($517,251)	($4,537,426)	($1,680,439)	($699,216)	($808,362)	($128,059)	($23,016,421)
1945	Measurement and Testing Equipment	($4,118,387)				($2,077,876)	($542,711)	($92,553)	($811,893)	($300,685)	($125,113)	($144,642)	($22,914)	($4,118,387)
1955	Communication Equipment	($23,568,800)				($11,891,315)	($3,105,839)	($529,664)	($4,646,321)	($1,720,768)	($715,997)	($827,762)	($131,132)	($23,568,800)
1960	Miscellaneous Equipment	($104,582)				($52,765)	($13,782)	($2,350)	($20,617)	($7,636)	($3,177)	($3,673)	($582)	($104,582)
1970	Load Management Controls - Customer Premises	($4,386,268)				($2,213,031)	($578,012)	($98,573)	($864,703)	($320,243)	($133,251)	($154,051)	($24,404)	($4,386,268)
1975	Load Management Controls - Utility Premises	($550,339)				($277,666)	($72,522)	($12,368)	($108,493)	($40,180)	($16,719)	($19,328)	($3,062)	($550,339)
1980	System Supervisory Equipment	($32,574,748)				($16,435,143)	($4,292,621)	($732,056)	($6,421,741)	($2,378,296)	($989,589)	($1,144,061)	($181,239)	($32,574,748)
2005	Property Under Capital Leases	($805,003)				($406,153)	($106,081)	($18,091)	($158,697)	($58,774)	($24,455)	($28,273)	($4,479)	($805,003)
	Sub - Total	**($352,397,440)**				($177,797,304)	($46,438,080)	($7,919,467)	($69,471,152)	($25,728,690)	($10,705,491)	($12,376,587)	($1,960,669)	($352,397,440)
	TOTAL - 2105 FA	($2,109,819,504)	($1,007,270,538)	($750,151,526)	($1,757,422,065)	($177,797,304)	($46,438,080)	($7,919,467)	($69,471,152)	($25,728,690)	($10,705,491)	($12,376,587)	($1,960,669)	($352,397,440)

Accumulated Depreciation - 2120

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	($241,703)	($241,703)	$0	($241,703)									
1815	Transformer Station Equipment - Normally Primary above 50 kV	($726,693)	($726,693)	$0	($726,693)									
	Sub - Total	**($968,396)**	**($968,396)**	**$0**	**($968,396)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	($2,279,018)				($1,149,847)	($300,323)	($51,217)	($449,283)	($166,392)	($69,234)	($80,042)	($12,680)	($2,279,018)
1910	Leasehold Improvements	($3,038,148)				($1,532,856)	($400,360)	($68,277)	($598,936)	($221,816)	($92,296)	($106,703)	($16,904)	($3,038,148)
	Sub - Total	**($5,317,166)**				**($2,682,703)**	**($700,683)**	**($119,493)**	**($1,048,219)**	**($388,209)**	**($161,530)**	**($186,745)**	**($29,584)**	**($5,317,166)**
	TOTAL - 2120	($6,285,561)	($968,396)	$0	($968,396)	($2,682,703)	($700,683)	($119,493)	($1,048,219)	($388,209)	($161,530)	($186,745)	($29,584)	($5,317,166)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$1,585,587	$0	$1,585,587	$1,585,587									
1808-1	Buildings and Fixtures > 50 kV	$29,412	$29,412	$0	$29,412									
1808-2	Buildings and Fixtures < 50 KV	$972,490	$972,490	$0	$972,490									
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$4,118,198	$4,118,198	$0	$4,118,198									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$708,786	$0	$708,786	$708,786									

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1830-4	Poles, Towers and Fixtures - Primary	$6,344,749	$4,124,087	$2,220,662	$6,344,749									
1830-5	Poles, Towers and Fixtures - Secondary	$5,821,609	$3,784,046	$2,037,563	$5,821,609									
1835-4	Overhead Conductors and Devices - Primary	$4,534,387	$2,947,352	$1,587,036	$4,534,387									
1835-5	Overhead Conductors and Devices - Secondary	$4,209,173	$2,735,962	$1,473,210	$4,209,173									
1840-4	Underground Conduit - Primary	$26,574,366	$17,273,338	$9,301,028	$26,574,366									
1840-5	Underground Conduit - Secondary	$8,276,596	$5,379,787	$2,896,809	$8,276,596									
1845-4	Underground Conductors and Devices - Primary	$12,031,214	$7,820,289	$4,210,925	$12,031,214									
1845-5	Underground Conductors and Devices - Secondary	$4,319,142	$2,807,442	$1,511,700	$4,319,142									
1850	Line Transformers	$19,828,777	$13,880,144	$5,948,633	$19,828,777									
1855	Services	$11,894,762	$0	$11,894,762	$11,894,762									
1860	Meters	$13,483,431	$0	$13,483,431	$13,483,431									
	Sub - Total	**$124,942,396**	**$66,082,264**	**$58,860,132**	**$124,942,396**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1908	Buildings and Fixtures	$2,150,230				$1,084,869	$283,352	$48,322	$423,893	$156,989	$65,322	$75,518	$11,963	$2,150,230
1915	Office Furniture and Equipment	$642,785				$324,308	$84,705	$14,445	$126,718	$46,930	$19,527	$22,575	$3,576	$642,785
1920	Computer Equipment - Hardware	$4,231,507				$2,134,949	$557,618	$95,095	$834,194	$308,944	$128,549	$148,615	$23,543	$4,231,507
1925	Computer Software	$16,275,794				$8,211,729	$2,144,785	$365,768	$3,208,588	$1,188,303	$494,443	$571,624	$90,555	$16,275,794
1930	Transportation Equipment	$4,773,599				$2,408,454	$629,053	$107,278	$941,061	$348,523	$145,017	$167,654	$26,559	$4,773,599
1935	Stores Equipment	$7,777				$3,924	$1,025	$175	$1,533	$568	$236	$273	$43	$7,777
1940	Tools, Shop and Garage Equipment	$1,176,132				$593,401	$154,988	$26,431	$231,861	$85,870	$35,730	$41,307	$6,544	$1,176,132
1945	Measurement and Testing Equipment	$84,963				$42,867	$11,196	$1,909	$16,749	$6,203	$2,581	$2,984	$473	$84,963
1955	Communication Equipment	$1,260,455				$635,945	$166,100	$28,326	$248,484	$92,026	$38,291	$44,269	$7,013	$1,260,455
1970	Load Management Controls - Customer Premises	$249,016				$125,638	$32,815	$5,596	$49,091	$18,181	$7,565	$8,746	$1,385	$249,016
1975	Load Management Controls - Utility Premises	$8,087				$4,080	$1,066	$182	$1,594	$590	$246	$284	$45	$8,087
1980	System Supervisory Equipment	$2,091,897				$1,055,438	$275,665	$47,011	$412,394	$152,730	$63,550	$73,470	$11,639	$2,091,897
2005	Property Under Capital Leases	$233,052				$117,583	$30,711	$5,237	$45,944	$17,015	$7,080	$8,185	$1,297	$233,052
	Sub - Total	**$33,185,294**				$16,743,186	$4,373,078	$745,777	$6,542,104	$2,422,873	$1,008,137	$1,165,504	$184,636	$33,185,294
	TOTAL - 5705	$158,127,690	$66,082,264	$58,860,132	$124,942,396	$16,743,186	$4,373,078	$745,777	$6,542,104	$2,422,873	$1,008,137	$1,165,504	$184,636	$33,185,294

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$29,704	$29,704	$0	$29,704									
	Sub - Total	**$29,704**	**$29,704**	**$0**	**$29,704**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	$174,787				$88,186	$23,033	$3,928	$34,457	$12,761	$5,310	$6,139	$972	$174,787
1910	Leasehold Improvements	$345,873				$174,505	$45,578	$7,773	$68,185	$25,252	$10,507	$12,147	$1,924	$345,873
	Sub - Total	**$520,660**				$262,692	$68,611	$11,701	$102,642	$38,014	$15,817	$18,286	$2,897	$520,660
	TOTAL - 5710	$550,364	$29,704	$0	$29,704	$262,692	$68,611	$11,701	$102,642	$38,014	$15,817	$18,286	$2,897	$520,660

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1815	Transformer Station Equipment - Normally Primary above 50 kV	$511,700	$511,700	$0	$511,700									
	Sub - Total	**$511,700**	**$511,700**	**$0**	**$511,700**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0

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TOTAL - 5715		$511,700	$511,700	$0	$511,700	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant														
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%									
1805	Land													
1805-1	Land Station >50 kV	100%	100%	0%	100%									
1805-2	Land Station <50 kV	100%	100%	0%	100%									
1806	Land Rights													
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%									
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%									
1808	Buildings and Fixtures													
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%									
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%									
1810	Leasehold Improvements													
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%									
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%									
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%									
1820	Distribution Station Equipment - Normally Primary below 50 kV													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%									
1825	Storage Battery Equipment													
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%									
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%									
1830	Poles, Towers and Fixtures													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%									
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%									
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%									
1835	Overhead Conductors and Devices													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%									
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%									
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%									
1840	Underground Conduit													
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%									
1840-4	Underground Conduit - Primary	100%	65%	35%	100%									
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%									
1845	Underground Conductors and Devices													
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%									
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%									

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1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%									
1850	Line Transformers	100%	70%	30%	100%									
1855	Services	100%	0%	100%	100%									
1860	Meters	100%	0%	100%	100%									
General Plant														
1905	Land	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1906	Land Rights	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1908	Buildings and Fixtures	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1910	Leasehold Improvements	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1915	Office Furniture and Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1920	Computer Equipment - Hardware	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1925	Computer Software	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1930	Transportation Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1935	Stores Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1940	Tools, Shop and Garage Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1945	Measurement and Testing Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1950	Power Operated Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1955	Communication Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1960	Miscellaneous Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1970	Load Management Controls - Customer Premises	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1975	Load Management Controls - Utility Premises	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1980	System Supervisory Equipment	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
1990	Other Tangible Property	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
2005	Property Under Capital Leases	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%
2010	Electric Plant Purchased or Sold	100%				50%	13%	2%	20%	7%	3%	4%	1%	100%

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Ontario

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Total
1830-4	Poles, Towers and Fixtures - Primary	($5,565,646)	($3,617,670)	($1,947,976)	($5,565,646)	($896,433)	($461,227)	($41,090)	($1,224,370)	($670,014)	($321,886)	$0	($2,650)	($3,617,670)
1835-4	Overhead Conductors and Devices - Primary	($5,417,291)	($3,521,239)	($1,896,052)	($5,417,291)	($872,539)	($448,933)	($39,995)	($1,191,734)	($652,155)	($313,306)	$0	($2,579)	($3,521,239)
1840-4	Underground Conduit - Primary	($34,242,586)	($22,257,681)	($11,984,905)	($34,242,586)	($5,515,299)	($2,837,695)	($252,805)	($7,532,925)	($4,122,256)	($1,980,399)	$0	($16,302)	($22,257,681)
1840-5	Underground Conduit - Secondary	($51,363,878)	($33,386,521)	($17,977,357)	($51,363,878)	($17,811,482)	($9,164,245)	($205,365)	($5,828,421)	($324,362)	$0	$0	($52,647)	($33,386,521)
1845-4	Underground Conductors and Devices - Primary	($40,866,722)	($26,563,369)	($14,303,353)	($40,866,722)	($6,582,218)	($3,386,639)	($301,710)	($8,990,149)	($4,919,695)	($2,363,502)	$0	($19,456)	($26,563,369)
1845-5	Underground Conductors and Devices - Secondary	($13,622,241)	($8,854,456)	($4,767,784)	($13,622,241)	($4,723,792)	($2,430,454)	($54,465)	($1,545,758)	($86,024)	$0	$0	($13,962)	($8,854,456)
1850	Line Transformers	($107,293,851)	($75,105,696)	($32,188,155)	($107,293,851)	($26,387,702)	($13,576,824)	($1,014,160)	($28,782,675)	($4,805,421)	($460,918)	$0	($77,996)	($75,105,696)
1855	Services	($3,199,205)	$0	($3,199,205)	($3,199,205)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($2,049,477)	$0	($2,049,477)	($2,049,477)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($263,620,895)**	**($173,306,632)**	**($90,314,263)**	**($263,620,895)**	**($62,789,465)**	**($32,306,017)**	**($1,909,589)**	**($55,096,031)**	**($15,579,927)**	**($5,440,011)**	**$0**	**($185,592)**	**($173,306,632)**
General Plant														
	Sub - Total	$0												
	TOTAL - 1995	($263,620,895)	($173,306,632)	($90,314,263)	($263,620,895)	($62,789,465)	($32,306,017)	($1,909,589)	($55,096,031)	($15,579,927)	($5,440,011)	$0	($185,592)	($173,306,632)

Accumulated Depreciation - 2105 Capital Contribution

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,487,299	$966,744	$520,555	$1,487,299	$239,553	$123,253	$10,980	$327,186	$179,047	$86,017	$0	$708	$966,744
1835-4	Overhead Conductors and Devices - Primary	$1,432,325	$931,011	$501,314	$1,432,325	$230,698	$118,697	$10,575	$315,093	$172,429	$82,838	$0	$682	$931,011
1840-4	Underground Conduit - Primary	$6,141,507	$3,991,979	$2,149,527	$6,141,507	$989,185	$508,949	$45,341	$1,351,052	$739,339	$355,190	$0	$2,924	$3,991,979
1840-5	Underground Conduit - Secondary	$9,212,260	$5,987,969	$3,224,291	$9,212,260	$3,194,541	$1,643,634	$36,833	$1,045,344	$58,175	$0	$0	$9,442	$5,987,969
1845-4	Underground Conductors and Devices - Primary	$8,908,167	$5,790,309	$3,117,858	$8,908,167	$1,434,798	$738,223	$65,767	$1,959,681	$1,072,400	$515,198	$0	$4,241	$5,790,309
1845-5	Underground Conductors and Devices - Secondary	$2,969,389	$1,930,103	$1,039,286	$2,969,389	$1,029,697	$529,793	$11,872	$336,946	$18,752	$0	$0	$3,044	$1,930,103
1850	Line Transformers	$16,602,488	$11,621,741	$4,980,746	$16,602,488	$4,083,193	$2,100,857	$156,930	$4,453,787	$743,583	$71,322	$0	$12,069	$11,621,741
1855	Services	$629,709	$0	$629,709	$629,709	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$654,986	$0	$654,986	$654,986	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$48,038,129**	**$31,219,856**	**$16,818,272**	**$48,038,129**	**$11,201,664**	**$5,763,405**	**$338,298**	**$9,789,090**	**$2,983,725**	**$1,110,565**	**$0**	**$33,110**	**$31,219,856**
General Plant														
	Sub - Total	**$0**												
	TOTAL - 2105 CC	$48,038,129	$31,219,856	$16,818,272	$48,038,129	$11,201,664	$5,763,405	$338,298	$9,789,090	$2,983,725	$1,110,565	$0	$33,110	$31,219,856

Accumulated Depreciation - 2105 Fixed Assets Only

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($5,687,733)	$0	($5,687,733)	($5,687,733)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	($573,262)	($573,262)	$0	($573,262)	($157,099)	($62,636)	($3,714)	($195,543)	($102,772)	($48,258)	($2,215)	($1,025)	($573,262)
1808-2	Buildings and Fixtures < 50 KV	($17,252,057)	($17,252,057)	$0	($17,252,057)	($4,727,816)	($1,885,014)	($111,773)	($5,884,771)	($3,092,890)	($1,452,292)	($66,657)	($30,845)	($17,252,057)
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,248,486)	($3,248,486)	$0	($3,248,486)	($890,227)	($354,940)	($21,046)	($1,108,076)	($582,377)	($273,460)	($12,551)	($5,808)	($3,248,486)
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($82,861,415)	($82,861,415)	$0	($82,861,415)	($20,532,483)	($10,564,236)	($941,150)	($28,043,749)	($15,346,432)	($7,372,677)	$0	($60,689)	($82,861,415)
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($1,855,042)	$0	($1,855,042)	($1,855,042)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	($87,232,693)	($56,701,250)	($30,531,442)	($87,232,693)	($14,050,176)	($7,229,003)	($644,019)	($19,190,061)	($10,501,412)	($5,045,050)	$0	($41,529)	($56,701,250)

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet O7 Amortization Output Worksheet

Ontario

1830-5	Poles, Towers and Fixtures - Secondary	($77,419,426)	($50,322,627)	($27,096,799)	($77,419,426)	($26,846,779)	($13,813,026)	($309,541)	($8,785,025)	($488,902)	$0	$0	($79,353)	($50,322,627)
1835-4	Overhead Conductors and Devices - Primary	($90,301,897)	($58,696,233)	($31,605,664)	($90,301,897)	($14,544,518)	($7,483,349)	($666,679)	($19,865,246)	($10,870,895)	($5,222,556)	$0	($42,990)	($58,696,233)
1835-5	Overhead Conductors and Devices - Secondary	($80,143,359)	($52,093,184)	($28,050,176)	($80,143,359)	($27,791,359)	($14,299,025)	($320,432)	($9,094,119)	($506,104)	$0	$0	($82,145)	($52,093,184)
1840-4	Underground Conduit - Primary	($404,962,348)	($263,225,526)	($141,736,822)	($404,962,348)	($65,225,455)	($33,559,366)	($2,989,746)	($89,086,465)	($48,750,948)	($23,420,753)	$0	($192,792)	($263,225,526)
1840-5	Underground Conduit - Secondary	($144,213,605)	($93,738,844)	($50,474,762)	($144,213,605)	($50,009,036)	($25,730,315)	($576,600)	($16,364,371)	($910,706)	$0	$0	($147,816)	($93,738,844)
1845-4	Underground Conductors and Devices - Primary	($180,563,451)	($117,366,243)	($63,197,208)	($180,563,451)	($29,082,539)	($14,963,354)	($1,333,059)	($39,721,618)	($21,736,933)	($10,442,778)	$0	($85,962)	($117,366,243)
1845-5	Underground Conductors and Devices - Secondary	($64,301,549)	($41,796,007)	($22,505,542)	($64,301,549)	($22,297,885)	($11,472,559)	($257,093)	($7,296,499)	($406,063)	$0	$0	($65,908)	($41,796,007)
1850	Line Transformers	($347,860,333)	($243,502,233)	($104,358,100)	($347,860,333)	($85,552,291)	($44,017,794)	($3,288,035)	($93,317,097)	($15,579,786)	($1,494,356)	$0	($252,874)	($243,502,233)
1855	Services	($186,117,123)	$0	($186,117,123)	($186,117,123)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	($121,421,455)	$0	($121,421,455)	($121,421,455)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($1,896,015,234)**	**($1,081,377,367)**	**($814,637,867)**	**($1,896,015,234)**	**($361,707,663)**	**($185,434,618)**	**($11,462,886)**	**($337,952,641)**	**($128,876,221)**	**($54,772,180)**	**($81,423)**	**($1,089,736)**	**($1,081,377,367)**
General Plant														
1908	Buildings and Fixtures	($33,173,948)												
1915	Office Furniture and Equipment	($19,507,322)												
1920	Computer Equipment - Hardware	($47,383,294)												
1925	Computer Software	($128,023,711)												
1930	Transportation Equipment	($59,412,446)												
1935	Stores Equipment	($5,472,220)												
1940	Tools, Shop and Garage Equipment	($24,194,869)												
1945	Measurement and Testing Equipment	($4,202,543)												
1955	Communication Equipment	($24,873,805)												
1960	Miscellaneous Equipment	($104,582)												
1970	Load Management Controls - Customer Premises	($4,628,690)												
1975	Load Management Controls - Utility Premises	($554,382)												
1980	System Supervisory Equipment	($34,669,165)												
2005	Property Under Capital Leases	($935,746)												
	Sub - Total	**($387,136,721)**												
	TOTAL - 2105 FA	($2,283,151,955)	($1,081,377,367)	($814,637,867)	($1,896,015,234)	($361,707,663)	($185,434,618)	($11,462,886)	($337,952,641)	($128,876,221)	($54,772,180)	($81,423)	($1,089,736)	($1,081,377,367)

Accumulated Depreciation - 2120

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	($271,407)	($271,407)	$0	($271,407)	($74,377)	($29,655)	($1,758)	($92,578)	($48,657)	($22,847)	($1,049)	($485)	($271,407)
1815	Transformer Station Equipment - Normally Primary above 50 kV	($1,553,394)	($1,553,394)	$0	($1,553,394)	($425,698)	($169,729)	($10,064)	($529,871)	($278,487)	($130,766)	($6,002)	($2,777)	($1,553,394)
	Sub - Total	**($1,824,801)**	**($1,824,801)**	**$0**	**($1,824,801)**	**($500,075)**	**($199,383)**	**($11,823)**	**($622,449)**	**($327,144)**	**($153,613)**	**($7,050)**	**($3,263)**	**($1,824,801)**
General Plant														
1906	Land Rights	($2,453,806)												
	Sub - Total	**($5,847,826)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 2120	($7,672,626)	($1,824,801)	$0	($1,824,801)	($500,075)	($199,383)	($11,823)	($622,449)	($327,144)	($153,613)	($7,050)	($3,263)	($1,824,801)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$1,659,293	$0	$1,659,293	$1,659,293	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV	$29,374	$29,374	$0	$29,374	$8,050	$3,209	$190	$10,020	$5,266	$2,473	$113	$53	$29,374
1808-2	Buildings and Fixtures < 50 KV	$1,007,540	$1,007,540	$0	$1,007,540	$276,110	$110,087	$6,528	$343,677	$180,628	$84,816	$3,893	$1,801	$1,007,540
1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717	$57,472	$22,914	$1,359	$71,536	$37,597	$17,654	$810	$375	$209,717

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$4,396,897	$4,396,897	$0	$4,396,897	$1,089,521	$560,573	$49,940	$1,488,093	$814,332	$391,218	$0	$3,220	$4,396,897
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$908,766	$0	$908,766	$908,766	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$6,550,534	$4,257,847	$2,292,687	$6,550,534	$1,055,065	$542,845	$48,361	$1,441,033	$788,579	$378,846	$0	$3,119	$4,257,847
1830-5	Poles, Towers and Fixtures - Secondary	$6,011,212	$3,907,288	$2,103,924	$6,011,212	$2,084,511	$1,072,509	$24,034	$682,111	$37,961	$0	$0	$6,161	$3,907,288
1835-4	Overhead Conductors and Devices - Primary	$4,555,016	$2,960,760	$1,594,256	$4,555,016	$733,656	$377,476	$33,629	$1,002,044	$548,351	$263,437	$0	$2,169	$2,960,760
1835-5	Overhead Conductors and Devices - Secondary	$4,234,913	$2,752,694	$1,482,220	$4,234,913	$1,468,543	$755,585	$16,932	$480,549	$26,743	$0	$0	$4,341	$2,752,694
1840-4	Underground Conduit - Primary	$28,263,682	$18,371,394	$9,892,289	$28,263,682	$4,552,304	$2,342,221	$208,664	$6,217,644	$3,402,492	$1,634,613	$0	$13,456	$18,371,394
1840-5	Underground Conduit - Secondary	$8,778,965	$5,706,327	$3,072,638	$8,778,965	$3,044,287	$1,566,326	$35,100	$996,177	$55,439	$0	$0	$8,998	$5,706,327
1845-4	Underground Conductors and Devices - Primary	$13,445,614	$8,739,649	$4,705,965	$13,445,614	$2,165,624	$1,114,243	$99,266	$2,957,861	$1,618,635	$777,619	$0	$6,401	$8,739,649
1845-5	Underground Conductors and Devices - Secondary	$4,825,343	$3,136,473	$1,688,870	$4,825,343	$1,673,287	$860,928	$19,293	$547,547	$30,472	$0	$0	$4,946	$3,136,473
1850	Line Transformers	$20,868,635	$14,608,045	$6,260,591	$20,868,635	$5,132,403	$2,640,690	$197,254	$5,598,225	$934,653	$89,649	$0	$15,170	$14,608,045
1855	Services	$12,230,873	$0	$12,230,873	$12,230,873	$0	$0	$0	$0	$0	$0	$0	$0	$0
1860	Meters	$15,915,540	$0	$15,915,540	$15,915,540	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$133,891,914**	**$70,084,004**	**$63,807,910**	**$133,891,914**	**$23,340,832**	**$11,969,606**	**$740,551**	**$21,836,515**	**$8,481,149**	**$3,640,324**	**$4,817**	**$70,209**	**$70,084,004**
General Plant														
1908	Buildings and Fixtures	$2,053,268												
1915	Office Furniture and Equipment	$515,741												
1920	Computer Equipment - Hardware	$5,132,994												
1925	Computer Software	$18,943,929												
1930	Transportation Equipment	$5,344,865												
1935	Stores Equipment	$7,742												
1940	Tools, Shop and Garage Equipment	$1,180,764												
1945	Measurement and Testing Equipment	$83,349												
1955	Communication Equipment	$1,349,555												
1970	Load Management Controls - Customer Premises	$235,828												
1980	System Supervisory Equipment	$2,096,937												
2005	Property Under Capital Leases	$38,433												
	Sub - Total	**$36,983,405**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$170,875,319	$70,084,004	$63,807,910	$133,891,914	$23,340,832	$11,969,606	$740,551	$21,836,515	$8,481,149	$3,640,324	$4,817	$70,209	$70,084,004

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$29,704	$29,704	$0	$29,704	$8,140	$3,246	$192	$10,132	$5,325	$2,501	$115	$53	$29,704
	Sub - Total	**$29,704**	**$29,704**	**$0**	**$29,704**	**$8,140**	**$3,246**	**$192**	**$10,132**	**$5,325**	**$2,501**	**$115**	**$53**	**$29,704**
General Plant														
1906	Land Rights	$174,787												
1910	Leasehold Improvements	$365,873												
	Sub - Total	**$540,660**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$570,364	$29,704	$0	$29,704	$8,140	$3,246	$192	$10,132	$5,325	$2,501	$115	$53	$29,704

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**

1815	Transformer Station Equipment - Normally Primary above 50 kV	$1,141,700	$1,141,700	$0	$1,141,700	$312,876	$124,746	$7,397	$389,440	$204,680	$96,109	$4,411	$2,041	$1,141,700
	Sub - Total	**$1,141,700**	**$1,141,700**	**$0**	**$1,141,700**	**$312,876**	**$124,746**	**$7,397**	**$389,440**	**$204,680**	**$96,109**	**$4,411**	**$2,041**	**$1,141,700**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$1,141,700	$1,141,700	$0	$1,141,700	$312,876	$124,746	$7,397	$389,440	$204,680	$96,109	$4,411	$2,041	$1,141,700

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Demand Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%	100.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%	100.00%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	53.35%	27.45%	0.62%	17.46%	0.97%	0.00%	0.00%	0.16%	100.00%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%	100.00%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	53.35%	27.45%	0.62%	17.46%	0.97%	0.00%	0.00%	0.16%	100.00%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1840-4	Underground Conduit - Primary	100%	65%	35%	100%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%	100.00%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	53.35%	27.45%	0.62%	17.46%	0.97%	0.00%	0.00%	0.16%	100.00%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%	100.00%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%	100.00%
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	53.35%	27.45%	0.62%	17.46%	0.97%	0.00%	0.00%	0.16%	100.00%
1850	Line Transformers	100%	70%	30%	100%	35.13%	18.08%	1.35%	38.32%	6.40%	0.61%	0.00%	0.10%	100.00%
1855	Services	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1860	Meters	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
General Plant														
1905	Land	100%												
1906	Land Rights	100%												
1908	Buildings and Fixtures	100%												
1910	Leasehold Improvements	100%												
1915	Office Furniture and Equipment	100%												
1920	Computer Equipment - Hardware	100%												
1925	Computer Software	100%												
1930	Transportation Equipment	100%												
1935	Stores Equipment	100%												
1940	Tools, Shop and Garage Equipment	100%												
1945	Measurement and Testing Equipment	100%												
1950	Power Operated Equipment	100%												
1955	Communication Equipment	100%												
1960	Miscellaneous Equipment	100%												
1970	Load Management Controls - Customer Premises	100%												
1975	Load Management Controls - Utility Premises	100%												
1980	System Supervisory Equipment	100%												
1990	Other Tangible Property	100%												
2005	Property Under Capital Leases	100%												
2010	Electric Plant Purchased or Sold	100%												

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Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	($5,565,646)	($3,617,670)	($1,947,976)	($5,565,646)	($1,539,543)	($151,309)	($600)	($25,628)	($1,230)	($111)	($201,098)	($28,458)	($1,947,976)
1835-4	Overhead Conductors and Devices - Primary	($5,417,291)	($3,521,239)	($1,896,052)	($5,417,291)	($1,498,506)	($147,275)	($584)	($24,944)	($1,197)	($108)	($195,738)	($27,700)	($1,896,052)
1840-4	Underground Conduit - Primary	($34,242,586)	($22,257,681)	($11,984,905)	($34,242,586)	($9,472,025)	($930,925)	($3,692)	($157,673)	($7,565)	($683)	($1,237,254)	($175,089)	($11,984,905)
1840-5	Underground Conduit - Secondary	($51,363,878)	($33,386,521)	($17,977,357)	($51,363,878)	($14,364,713)	($1,411,786)	($1,408)	($57,289)	($280)	($7)	($1,876,346)	($265,529)	($17,977,357)
1845-4	Underground Conductors and Devices - Primary	($40,866,722)	($26,563,369)	($14,303,353)	($40,866,722)	($11,304,362)	($1,111,010)	($4,406)	($188,175)	($9,028)	($815)	($1,476,597)	($208,959)	($14,303,353)
1845-5	Underground Conductors and Devices - Secondary	($13,622,241)	($8,854,456)	($4,767,784)	($13,622,241)	($3,809,673)	($374,421)	($373)	($15,194)	($74)	($2)	($497,627)	($70,421)	($4,767,784)
1850	Line Transformers	($107,293,851)	($75,105,696)	($32,188,155)	($107,293,851)	($25,521,688)	($2,508,311)	($8,340)	($339,281)	($4,966)	($113)	($3,333,692)	($471,764)	($32,188,155)
1855	Services	($3,199,205)	$0	($3,199,205)	($3,199,205)	($2,306,996)	($453,470)	($2,262)	($92,007)	($449)	($32)	($301,344)	($42,644)	($3,199,205)
1860	Meters	($2,049,477)	$0	($2,049,477)	($2,049,477)	($1,386,615)	($197,062)	($5,266)	($400,437)	($54,304)	($5,792)	$0	$0	($2,049,477)
	Sub - Total	**($263,620,895)**	**($173,306,632)**	**($90,314,263)**	**($263,620,895)**	**($71,204,121)**	**($7,285,570)**	**($26,932)**	**($1,300,627)**	**($79,091)**	**($7,662)**	**($9,119,696)**	**($1,290,564)**	**($90,314,263)**
General Plant														
	Sub - Total	$0												
	TOTAL - 1995	($263,620,895)	($173,306,632)	($90,314,263)	($263,620,895)	($71,204,121)	($7,285,570)	($26,932)	($1,300,627)	($79,091)	($7,662)	($9,119,696)	($1,290,564)	($90,314,263)

Accumulated Depreciation - 2105 Capital Contribution

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,487,299	$966,744	$520,555	$1,487,299	$411,410	$40,434	$160	$6,848	$329	$30	$53,739	$7,605	$520,555
1835-4	Overhead Conductors and Devices - Primary	$1,432,325	$931,011	$501,314	$1,432,325	$396,203	$38,939	$154	$6,595	$316	$29	$51,753	$7,324	$501,314
1840-4	Underground Conduit - Primary	$6,141,507	$3,991,979	$2,149,527	$6,141,507	$1,698,835	$166,964	$662	$28,279	$1,357	$122	$221,905	$31,403	$2,149,527
1840-5	Underground Conduit - Secondary	$9,212,260	$5,987,969	$3,224,291	$9,212,260	$2,576,353	$253,208	$253	$10,275	$50	$1	$336,528	$47,623	$3,224,291
1845-4	Underground Conductors and Devices - Primary	$8,908,167	$5,790,309	$3,117,858	$8,908,167	$2,464,136	$242,179	$960	$41,019	$1,968	$178	$321,870	$45,549	$3,117,858
1845-5	Underground Conductors and Devices - Secondary	$2,969,389	$1,930,103	$1,039,286	$2,969,389	$830,436	$81,617	$81	$3,312	$16	$0	$108,473	$15,350	$1,039,286
1850	Line Transformers	$16,602,488	$11,621,741	$4,980,746	$16,602,488	$3,949,187	$388,132	$1,291	$52,500	$768	$17	$515,850	$73,000	$4,980,746
1855	Services	$629,709	$0	$629,709	$629,709	$454,093	$89,258	$445	$18,110	$88	$6	$59,314	$8,394	$629,709
1860	Meters	$654,986	$0	$654,986	$654,986	$443,144	$62,978	$1,683	$127,974	$17,355	$1,851	$0	$0	$654,986
	Sub - Total	**$48,038,129**	**$31,219,856**	**$16,818,272**	**$48,038,129**	**$13,223,796**	**$1,363,710**	**$5,690**	**$294,912**	**$22,247**	**$2,235**	**$1,669,433**	**$236,248**	**$16,818,272**
General Plant														
	Sub - Total	**$0**												
	TOTAL - 2105 CC	$48,038,129	$31,219,856	$16,818,272	$48,038,129	$13,223,796	$1,363,710	$5,690	$294,912	$22,247	$2,235	$1,669,433	$236,248	$16,818,272

Accumulated Depreciation - 2105 Fixed Assets Only

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($5,687,733)	$0	($5,687,733)	($5,687,733)	($2,858,208)	($905,877)	($61,163)	($1,124,251)	($420,338)	($180,567)	($117,639)	($19,691)	($5,687,733)
1808-1	Buildings and Fixtures > 50 kV	($573,262)	($573,262)	$0	($573,262)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	($17,252,057)	($17,252,057)	$0	($17,252,057)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,248,486)	($3,248,486)	$0	($3,248,486)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($82,861,415)	($82,861,415)	$0	($82,861,415)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($1,855,042)	$0	($1,855,042)	($1,855,042)	($416,208)	($185,225)	($10,980)	($676,500)	($366,865)	($187,120)	($7,956)	($4,188)	($1,855,042)

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1830-4	Poles, Towers and Fixtures - Primary	($87,232,693)	($56,701,250)	($30,531,442)	($87,232,693)	($24,129,901)	($2,371,524)	($9,405)	($401,672)	($19,271)	($1,739)	($3,151,894)	($446,037)	($30,531,442)
1830-5	Poles, Towers and Fixtures - Secondary	($77,419,426)	($50,322,627)	($27,096,799)	($77,419,426)	($21,651,555)	($2,127,948)	($2,123)	($86,350)	($421)	($10)	($2,828,167)	($400,225)	($27,096,799)
1835-4	Overhead Conductors and Devices - Primary	($90,301,897)	($58,696,233)	($31,605,664)	($90,301,897)	($24,978,890)	($2,454,964)	($9,736)	($415,804)	($19,949)	($1,800)	($3,262,790)	($461,730)	($31,605,664)
1835-5	Overhead Conductors and Devices - Secondary	($80,143,359)	($52,093,184)	($28,050,176)	($80,143,359)	($22,413,345)	($2,202,818)	($2,197)	($89,388)	($436)	($11)	($2,927,674)	($414,307)	($28,050,176)
1840-4	Underground Conduit - Primary	($404,962,348)	($263,225,526)	($141,736,822)	($404,962,348)	($112,018,800)	($11,009,381)	($43,660)	($1,864,690)	($89,462)	($8,073)	($14,632,110)	($2,070,647)	($141,736,822)
1840-5	Underground Conduit - Secondary	($144,213,605)	($93,738,844)	($50,474,762)	($144,213,605)	($40,331,592)	($3,963,851)	($3,954)	($160,849)	($785)	($19)	($5,268,190)	($745,522)	($50,474,762)
1845-4	Underground Conductors and Devices - Primary	($180,563,451)	($117,366,243)	($63,197,208)	($180,563,451)	($49,946,621)	($4,908,831)	($19,467)	($831,423)	($39,889)	($3,600)	($6,524,123)	($923,254)	($63,197,208)
1845-5	Underground Conductors and Devices - Secondary	($64,301,549)	($41,796,007)	($22,505,542)	($64,301,549)	($17,982,935)	($1,767,391)	($1,763)	($71,719)	($350)	($8)	($2,348,965)	($332,411)	($22,505,542)
1850	Line Transformers	($347,860,333)	($243,502,233)	($104,358,100)	($347,860,333)	($82,744,564)	($8,132,264)	($27,041)	($1,099,994)	($16,101)	($365)	($10,808,253)	($1,529,518)	($104,358,100)
1855	Services	($186,117,123)	$0	($186,117,123)	($186,117,123)	($134,211,940)	($26,381,114)	($131,581)	($5,352,579)	($26,116)	($1,890)	($17,531,020)	($2,480,883)	($186,117,123)
1860	Meters	($121,421,455)	$0	($121,421,455)	($121,421,455)	($82,150,176)	($11,674,964)	($312,006)	($23,723,925)	($3,217,217)	($343,168)	$0	$0	($121,421,455)
	Sub - Total	**($1,896,015,234)**	**($1,081,377,367)**	**($814,637,867)**	**($1,896,015,234)**	**($615,834,736)**	**($78,086,153)**	**($635,074)**	**($35,899,141)**	**($4,217,199)**	**($728,370)**	**($69,408,781)**	**($9,828,413)**	**($814,637,867)**
General Plant														
1908	Buildings and Fixtures	($33,173,948)												
1915	Office Furniture and Equipment	($19,507,322)												
1920	Computer Equipment - Hardware	($47,383,294)												
1925	Computer Software	($128,023,711)												
1930	Transportation Equipment	($59,412,446)												
1935	Stores Equipment	($5,472,220)												
1940	Tools, Shop and Garage Equipment	($24,194,869)												
1945	Measurement and Testing Equipment	($4,202,543)												
1955	Communication Equipment	($24,873,805)												
1960	Miscellaneous Equipment	($104,582)												
1970	Load Management Controls - Customer Premises	($4,628,690)												
1975	Load Management Controls - Utility Premises	($554,382)												
1980	System Supervisory Equipment	($34,669,165)												
2005	Property Under Capital Leases	($935,746)												
	Sub - Total	**($387,136,721)**												
	TOTAL - 2105 FA	($2,283,151,955)	($1,081,377,367)	($814,637,867)	($1,896,015,234)	($615,834,736)	($78,086,153)	($635,074)	($35,899,141)	($4,217,199)	($728,370)	($69,408,781)	($9,828,413)	($814,637,867)

Accumulated Depreciation - 2120

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	($271,407)	($271,407)	$0	($271,407)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($1,553,394)	($1,553,394)	$0	($1,553,394)	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($1,824,801)**	**($1,824,801)**	**$0**	**($1,824,801)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	($2,453,806)												
	Sub - Total	**($5,847,826)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 2120	($7,672,626)	($1,824,801)	$0	($1,824,801)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$1,659,293	$0	$1,659,293	$1,659,293	$833,830	$264,273	$17,843	$327,980	$122,626	$52,677	$34,319	$5,745	$1,659,293
1808-1	Buildings and Fixtures > 50 kV	$29,374	$29,374	$0	$29,374	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 KV	$1,007,540	$1,007,540	$0	$1,007,540	$0	$0	$0	$0	$0	$0	$0	$0	$0

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1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$4,396,897	$4,396,897	$0	$4,396,897	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$908,766	$0	$908,766	$908,766	$203,896	$90,740	$5,379	$331,410	$179,723	$91,668	$3,897	$2,052	$908,766
1830-4	Poles, Towers and Fixtures - Primary	$6,550,534	$4,257,847	$2,292,687	$6,550,534	$1,811,978	$178,084	$706	$30,163	$1,447	$131	$236,684	$33,494	$2,292,687
1830-5	Poles, Towers and Fixtures - Secondary	$6,011,212	$3,907,288	$2,103,924	$6,011,212	$1,681,129	$165,224	$165	$6,705	$33	$1	$219,592	$31,075	$2,103,924
1835-4	Overhead Conductors and Devices - Primary	$4,555,016	$2,960,760	$1,594,256	$4,555,016	$1,259,987	$123,833	$491	$20,974	$1,006	$91	$164,582	$23,291	$1,594,256
1835-5	Overhead Conductors and Devices - Secondary	$4,234,913	$2,752,694	$1,482,220	$4,234,913	$1,184,360	$116,401	$116	$4,723	$23	$1	$154,703	$21,893	$1,482,220
1840-4	Underground Conduit - Primary	$28,263,682	$18,371,394	$9,892,289	$28,263,682	$7,818,168	$768,382	$3,047	$130,143	$6,244	$563	$1,021,224	$144,517	$9,892,289
1840-5	Underground Conduit - Secondary	$8,778,965	$5,706,327	$3,072,638	$8,778,965	$2,455,175	$241,298	$241	$9,792	$48	$1	$320,700	$45,383	$3,072,638
1845-4	Underground Conductors and Devices - Primary	$13,445,614	$8,739,649	$4,705,965	$13,445,614	$3,719,263	$365,535	$1,450	$61,912	$2,970	$268	$485,817	$68,750	$4,705,965
1845-5	Underground Conductors and Devices - Secondary	$4,825,343	$3,136,473	$1,688,870	$4,825,343	$1,349,483	$132,629	$132	$5,382	$26	$1	$176,272	$24,945	$1,688,870
1850	Line Transformers	$20,868,635	$14,608,045	$6,260,591	$20,868,635	$4,963,964	$487,866	$1,622	$65,990	$966	$22	$648,402	$91,758	$6,260,591
1855	Services	$12,230,873	$0	$12,230,873	$12,230,873	$8,819,872	$1,733,661	$8,647	$351,750	$1,716	$124	$1,152,069	$163,034	$12,230,873
1860	Meters	$15,915,540	$0	$15,915,540	$15,915,540	$10,767,985	$1,530,317	$40,897	$3,109,657	$421,703	$44,981	$0	$0	$15,915,540
	Sub - Total	**$133,891,914**	**$70,084,004**	**$63,807,910**	**$133,891,914**	**$46,869,091**	**$6,198,244**	**$80,736**	**$4,456,580**	**$738,531**	**$190,529**	**$4,618,262**	**$655,936**	**$63,807,910**
General Plant														
1908	Buildings and Fixtures	$2,053,268												
1915	Office Furniture and Equipment	$515,741												
1920	Computer Equipment - Hardware	$5,132,994												
1925	Computer Software	$18,943,929												
1930	Transportation Equipment	$5,344,865												
1935	Stores Equipment	$7,742												
1940	Tools, Shop and Garage Equipment	$1,180,764												
1945	Measurement and Testing Equipment	$83,349												
1955	Communication Equipment	$1,349,555												
1970	Load Management Controls - Customer Premises	$235,828												
1980	System Supervisory Equipment	$2,096,937												
2005	Property Under Capital Leases	$38,433												
	Sub - Total	**$36,983,405**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5705	$170,875,319	$70,084,004	$63,807,910	$133,891,914	$46,869,091	$6,198,244	$80,736	$4,456,580	$738,531	$190,529	$4,618,262	$655,936	$63,807,910

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$29,704	$29,704	$0	$29,704	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$29,704**	**$29,704**	**$0**	**$29,704**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	$174,787												
1910	Leasehold Improvements	$365,873												
	Sub - Total	**$540,660**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$570,364	$29,704	$0	$29,704	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

	Customer Allocation 1	2	3	4	5	6	7	9	Sub -total

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Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1815	Transformer Station Equipment - Normally Primary above 50 kV	$1,141,700	$1,141,700	$0	$1,141,700	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$1,141,700**	**$1,141,700**	**$0**	**$1,141,700**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$1,141,700	$1,141,700	$0	$1,141,700	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						Customer Allocation 1	2	3	4	5	6	7	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%	50.25%	15.93%	1.08%	19.77%	7.39%	3.17%	2.07%	0.35%	100.00%
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-1	Land Station >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1805-2	Land Station <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820	Distribution Station Equipment - Normally Primary below 50 kV					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	22.44%	9.98%	0.59%	36.47%	19.78%	10.09%	0.43%	0.23%	100.00%
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%	79.03%	7.77%	0.03%	1.32%	0.06%	0.01%	10.32%	1.46%	100.00%
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%	79.90%	7.85%	0.01%	0.32%	0.00%	0.00%	10.44%	1.48%	100.00%
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%	79.03%	7.77%	0.03%	1.32%	0.06%	0.01%	10.32%	1.46%	100.00%
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%	79.90%	7.85%	0.01%	0.32%	0.00%	0.00%	10.44%	1.48%	100.00%
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1840-4	Underground Conduit - Primary	100%	65%	35%	100%	79.03%	7.77%	0.03%	1.32%	0.06%	0.01%	10.32%	1.46%	100.00%
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%	79.90%	7.85%	0.01%	0.32%	0.00%	0.00%	10.44%	1.48%	100.00%
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%	79.03%	7.77%	0.03%	1.32%	0.06%	0.01%	10.32%	1.46%	100.00%
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%	79.90%	7.85%	0.01%	0.32%	0.00%	0.00%	10.44%	1.48%	100.00%
1850	Line Transformers	100%	70%	30%	100%	79.29%	7.79%	0.03%	1.05%	0.02%	0.00%	10.36%	1.47%	100.00%
1855	Services	100%	0%	100%	100%	72.11%	14.17%	0.07%	2.88%	0.01%	0.00%	9.42%	1.33%	100.00%
1860	Meters	100%	0%	100%	100%	67.66%	9.62%	0.26%	19.54%	2.65%	0.28%	0.00%	0.00%	100.00%
General Plant														
1905	Land	100%												
1906	Land Rights	100%												
1908	Buildings and Fixtures	100%												
1910	Leasehold Improvements	100%												
1915	Office Furniture and Equipment	100%												
1920	Computer Equipment - Hardware	100%												
1925	Computer Software	100%												
1930	Transportation Equipment	100%												
1935	Stores Equipment	100%												
1940	Tools, Shop and Garage Equipment	100%												
1945	Measurement and Testing Equipment	100%												
1950	Power Operated Equipment	100%												
1955	Communication Equipment	100%												
1960	Miscellaneous Equipment	100%												
1970	Load Management Controls - Customer Premises	100%												
1975	Load Management Controls - Utility Premises	100%												
1980	System Supervisory Equipment	100%												
1990	Other Tangible Property	100%												
2005	Property Under Capital Leases	100%												
2010	Electric Plant Purchased or Sold	100%												

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Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	($5,565,646)	($3,617,670)	($1,947,976)	($5,565,646)									
1835-4	Overhead Conductors and Devices - Primary	($5,417,291)	($3,521,239)	($1,896,052)	($5,417,291)									
1840-4	Underground Conduit - Primary	($34,242,586)	($22,257,681)	($11,984,905)	($34,242,586)									
1840-5	Underground Conduit - Secondary	($51,363,878)	($33,386,521)	($17,977,357)	($51,363,878)									
1845-4	Underground Conductors and Devices - Primary	($40,866,722)	($26,563,369)	($14,303,353)	($40,866,722)									
1845-5	Underground Conductors and Devices - Secondary	($13,622,241)	($8,854,456)	($4,767,784)	($13,622,241)									
1850	Line Transformers	($107,293,851)	($75,105,696)	($32,188,155)	($107,293,851)									
1855	Services	($3,199,205)	$0	($3,199,205)	($3,199,205)									
1860	Meters	($2,049,477)	$0	($2,049,477)	($2,049,477)									
	Sub - Total	**($263,620,895)**	**($173,306,632)**	**($90,314,263)**	**($263,620,895)**									
General Plant														
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 1995	($263,620,895)	($173,306,632)	($90,314,263)	($263,620,895)	$0	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Capital Contribution

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$1,487,299	$966,744	$520,555	$1,487,299									
1835-4	Overhead Conductors and Devices - Primary	$1,432,325	$931,011	$501,314	$1,432,325									
1840-4	Underground Conduit - Primary	$6,141,507	$3,991,979	$2,149,527	$6,141,507									
1840-5	Underground Conduit - Secondary	$9,212,260	$5,987,969	$3,224,291	$9,212,260									
1845-4	Underground Conductors and Devices - Primary	$8,908,167	$5,790,309	$3,117,858	$8,908,167									
1845-5	Underground Conductors and Devices - Secondary	$2,969,389	$1,930,103	$1,039,286	$2,969,389									
1850	Line Transformers	$16,602,488	$11,621,741	$4,980,746	$16,602,488									
1855	Services	$629,709	$0	$629,709	$629,709									
1860	Meters	$654,986	$0	$654,986	$654,986									
	Sub - Total	**$48,038,129**	**$31,219,856**	**$16,818,272**	**$48,038,129**									
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 2105 CC	$48,038,129	$31,219,856	$16,818,272	$48,038,129	$0	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Fixed Assets Only

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1565	Conservation and Demand Management	($5,687,733)	$0	($5,687,733)	($5,687,733)									
1808-1	Buildings and Fixtures > 50 kV	($573,262)	($573,262)	$0	($573,262)									
1808-2	Buildings and Fixtures < 50 KV	($17,252,057)	($17,252,057)	$0	($17,252,057)									
1815	Transformer Station Equipment - Normally Primary above 50 kV	($3,248,486)	($3,248,486)	$0	($3,248,486)									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($82,861,415)	($82,861,415)	$0	($82,861,415)									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($1,855,042)	$0	($1,855,042)	($1,855,042)									

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1830-4	Poles, Towers and Fixtures - Primary	($87,232,693)	($56,701,250)	($30,531,442)	($87,232,693)									
1830-5	Poles, Towers and Fixtures - Secondary	($77,419,426)	($50,322,627)	($27,096,799)	($77,419,426)									
1835-4	Overhead Conductors and Devices - Primary	($90,301,897)	($58,696,233)	($31,605,664)	($90,301,897)									
1835-5	Overhead Conductors and Devices - Secondary	($80,143,359)	($52,093,184)	($28,050,176)	($80,143,359)									
1840-4	Underground Conduit - Primary	($404,962,348)	($263,225,526)	($141,736,822)	($404,962,348)									
1840-5	Underground Conduit - Secondary	($144,213,605)	($93,738,844)	($50,474,762)	($144,213,605)									
1845-4	Underground Conductors and Devices - Primary	($180,563,451)	($117,366,243)	($63,197,208)	($180,563,451)									
1845-5	Underground Conductors and Devices - Secondary	($64,301,549)	($41,796,007)	($22,505,542)	($64,301,549)									
1850	Line Transformers	($347,860,333)	($243,502,233)	($104,358,100)	($347,860,333)									
1855	Services	($186,117,123)	$0	($186,117,123)	($186,117,123)									
1860	Meters	($121,421,455)	$0	($121,421,455)	($121,421,455)									
	Sub - Total	**($1,896,015,234)**	**($1,081,377,367)**	**($814,637,867)**	**($1,896,015,234)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1908	Buildings and Fixtures	($33,173,948)				($16,827,810)	($4,502,219)	($212,424)	($6,877,557)	($2,464,432)	($1,027,753)	($1,088,268)	($173,486)	($33,173,948)
1915	Office Furniture and Equipment	($19,507,322)				($9,895,280)	($2,647,446)	($124,912)	($4,044,219)	($1,449,163)	($604,351)	($639,936)	($102,015)	($19,507,322)
1920	Computer Equipment - Hardware	($47,383,294)				($24,035,639)	($6,430,648)	($303,411)	($9,823,411)	($3,520,018)	($1,467,968)	($1,554,404)	($247,794)	($47,383,294)
1925	Computer Software	($128,023,711)				($64,941,279)	($17,374,803)	($819,779)	($26,541,623)	($9,510,646)	($3,966,266)	($4,199,806)	($669,509)	($128,023,711)
1930	Transportation Equipment	($59,412,446)				($30,137,544)	($8,063,190)	($380,438)	($12,317,271)	($4,413,641)	($1,840,640)	($1,949,020)	($310,702)	($59,412,446)
1935	Stores Equipment	($5,472,220)				($2,775,837)	($742,665)	($35,040)	($1,134,490)	($406,521)	($169,533)	($179,516)	($28,617)	($5,472,220)
1940	Tools, Shop and Garage Equipment	($24,194,869)				($12,273,084)	($3,283,619)	($154,928)	($5,016,032)	($1,797,392)	($749,574)	($793,710)	($126,529)	($24,194,869)
1945	Measurement and Testing Equipment	($4,202,543)				($2,131,781)	($570,350)	($26,910)	($871,263)	($312,199)	($130,198)	($137,864)	($21,977)	($4,202,543)
1955	Communication Equipment	($24,873,805)				($12,617,481)	($3,375,761)	($159,275)	($5,156,788)	($1,847,829)	($770,608)	($815,983)	($130,079)	($24,873,805)
1960	Miscellaneous Equipment	($104,582)				($53,050)	($14,193)	($670)	($21,682)	($7,769)	($3,240)	($3,431)	($547)	($104,582)
1970	Load Management Controls - Customer Premises	($4,628,690)				($2,347,948)	($628,185)	($29,639)	($959,611)	($343,857)	($143,400)	($151,844)	($24,206)	($4,628,690)
1975	Load Management Controls - Utility Premises	($554,382)				($281,216)	($75,238)	($3,550)	($114,933)	($41,184)	($17,175)	($18,186)	($2,899)	($554,382)
1980	System Supervisory Equipment	($34,669,165)				($17,586,273)	($4,705,143)	($221,998)	($7,187,543)	($2,575,509)	($1,074,076)	($1,137,319)	($181,305)	($34,669,165)
2005	Property Under Capital Leases	($935,746)				($474,666)	($126,995)	($5,992)	($193,997)	($69,515)	($28,990)	($30,697)	($4,894)	($935,746)
	Sub - Total	**($387,136,721)**				($196,378,888)	($52,540,457)	($2,478,966)	($80,260,420)	($28,759,675)	($11,993,773)	($12,699,983)	($2,024,559)	($387,136,721)
	TOTAL - 2105 FA	($2,283,151,955)	($1,081,377,367)	($814,637,867)	($1,896,015,234)	($196,378,888)	($52,540,457)	($2,478,966)	($80,260,420)	($28,759,675)	($11,993,773)	($12,699,983)	($2,024,559)	($387,136,721)

Accumulated Depreciation - 2120

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Accumulated Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	($271,407)	($271,407)	$0	($271,407)									
1815	Transformer Station Equipment - Normally Primary above 50 kV	($1,553,394)	($1,553,394)	$0	($1,553,394)									
	Sub - Total	**($1,824,801)**	**($1,824,801)**	**$0**	**($1,824,801)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	($2,453,806)				($1,244,717)	($333,019)	($15,713)	($508,718)	($182,289)	($76,021)	($80,497)	($12,832)	($2,453,806)
	Sub - Total	**($5,847,826)**				**($2,966,367)**	**($793,641)**	**($37,446)**	**($1,212,360)**	**($434,424)**	**($181,170)**	**($191,837)**	**($30,582)**	**($5,847,826)**
	TOTAL - 2120	($7,672,626)	($1,824,801)	$0	($1,824,801)	($2,966,367)	($793,641)	($37,446)	($1,212,360)	($434,424)	($181,170)	($191,837)	($30,582)	($5,847,826)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	$1,659,293	$0	$1,659,293	$1,659,293									
1808-1	Buildings and Fixtures > 50 kV	$29,374	$29,374	$0	$29,374									
1808-2	Buildings and Fixtures < 50 KV	$1,007,540	$1,007,540	$0	$1,007,540									

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1815	Transformer Station Equipment - Normally Primary above 50 kV	$209,717	$209,717	$0	$209,717									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$4,396,897	$4,396,897	$0	$4,396,897									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$908,766	$0	$908,766	$908,766									
1830-4	Poles, Towers and Fixtures - Primary	$6,550,534	$4,257,847	$2,292,687	$6,550,534									
1830-5	Poles, Towers and Fixtures - Secondary	$6,011,212	$3,907,288	$2,103,924	$6,011,212									
1835-4	Overhead Conductors and Devices - Primary	$4,555,016	$2,960,760	$1,594,256	$4,555,016									
1835-5	Overhead Conductors and Devices - Secondary	$4,234,913	$2,752,694	$1,482,220	$4,234,913									
1840-4	Underground Conduit - Primary	$28,263,682	$18,371,394	$9,892,289	$28,263,682									
1840-5	Underground Conduit - Secondary	$8,778,965	$5,706,327	$3,072,638	$8,778,965									
1845-4	Underground Conductors and Devices - Primary	$13,445,614	$8,739,649	$4,705,965	$13,445,614									
1845-5	Underground Conductors and Devices - Secondary	$4,825,343	$3,136,473	$1,688,870	$4,825,343									
1850	Line Transformers	$20,868,635	$14,608,045	$6,260,591	$20,868,635									
1855	Services	$12,230,873	$0	$12,230,873	$12,230,873									
1860	Meters	$15,915,540	$0	$15,915,540	$15,915,540									
	Sub - Total	**$133,891,914**	**$70,084,004**	**$63,807,910**	**$133,891,914**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1908	Buildings and Fixtures	$2,053,268				$1,041,540	$278,660	$13,148	$425,679	$152,534	$63,612	$67,357	$10,738	$2,053,268
1915	Office Furniture and Equipment	$515,741				$261,615	$69,994	$3,302	$106,922	$38,313	$15,978	$16,919	$2,697	$515,741
1920	Computer Equipment - Hardware	$5,132,994				$2,603,761	$696,627	$32,868	$1,064,162	$381,321	$159,024	$168,387	$26,843	$5,132,994
1925	Computer Software	$18,943,929				$9,609,493	$2,570,985	$121,304	$3,927,418	$1,407,310	$586,896	$621,454	$99,069	$18,943,929
1930	Transportation Equipment	$5,344,865				$2,711,235	$725,381	$34,225	$1,108,087	$397,060	$165,588	$175,338	$27,951	$5,344,865
1935	Stores Equipment	$7,742				$3,927	$1,051	$50	$1,605	$575	$240	$254	$40	$7,742
1940	Tools, Shop and Garage Equipment	$1,180,764				$598,954	$160,248	$7,561	$244,794	$87,717	$36,581	$38,735	$6,175	$1,180,764
1945	Measurement and Testing Equipment	$83,349				$42,280	$11,312	$534	$17,280	$6,192	$2,582	$2,734	$436	$83,349
1955	Communication Equipment	$1,349,555				$684,575	$183,156	$8,642	$279,787	$100,256	$41,810	$44,272	$7,058	$1,349,555
1970	Load Management Controls - Customer Premises	$235,828				$119,626	$32,006	$1,510	$48,891	$17,519	$7,306	$7,736	$1,233	$235,828
1980	System Supervisory Equipment	$2,096,937				$1,063,692	$284,587	$13,427	$434,733	$155,778	$64,965	$68,790	$10,966	$2,096,937
2005	Property Under Capital Leases	$38,433				$19,496	$5,216	$246	$7,968	$2,855	$1,191	$1,261	$201	$38,433
	Sub - Total	**$36,983,405**				$18,760,194	$5,019,222	$236,817	$7,667,326	$2,747,429	$1,145,772	$1,213,237	$193,407	$36,983,405
	TOTAL - 5705	$170,875,319	$70,084,004	$63,807,910	$133,891,914	$18,760,194	$5,019,222	$236,817	$7,667,326	$2,747,429	$1,145,772	$1,213,237	$193,407	$36,983,405

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1806-2	Land Rights Station <50 kV	$29,704	$29,704	$0	$29,704									
	Sub - Total	**$29,704**	**$29,704**	**$0**	**$29,704**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
1906	Land Rights	$174,787				$88,662	$23,721	$1,119	$36,236	$12,985	$5,415	$5,734	$914	$174,787
1910	Leasehold Improvements	$365,873				$185,593	$49,655	$2,343	$75,852	$27,180	$11,335	$12,002	$1,913	$365,873
	Sub - Total	**$540,660**				$274,255	$73,376	$3,462	$112,089	$40,165	$16,750	$17,736	$2,827	$540,660
	TOTAL - 5710	$570,364	$29,704	$0	$29,704	$274,255	$73,376	$3,462	$112,089	$40,165	$16,750	$17,736	$2,827	$540,660

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

	A & G Allocation								
	1	2	3	4	5	6	7	9	Sub -total

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Account	Description	Depreciation	Demand	Customer	Total	Residential	GS <50	GS>50 Non RIMS	GS> 50 RIMS	GS >50-Intermediate	Large Use >5MW	Street Light	Unmetered Scattered Load	Sub -total
1815	Transformer Station Equipment - Normally Primary above 50 kV	$1,141,700	$1,141,700	$0	$1,141,700									
	Sub - Total	**$1,141,700**	**$1,141,700**	**$0**	**$1,141,700**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5715	$1,141,700	$1,141,700	$0	$1,141,700	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant														
	Sub - Total	**$0**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						A & G Allocation								
						1	2	3	4	5	6	7	9	Sub -total
Account	**Description**		**Demand**	**Customer**	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**	**Sub -total**
1565	Conservation and Demand Management	100%	0%	100%	100%									
1805	Land													
1805-1	Land Station >50 kV	100%	100%	0%	100%									
1805-2	Land Station <50 kV	100%	100%	0%	100%									
1806	Land Rights													
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%									
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%									
1808	Buildings and Fixtures													
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%									
1808-2	Buildings and Fixtures < 50 KV	100%	100%	0%	100%									
1810	Leasehold Improvements													
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%									
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%									
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%									
1820	Distribution Station Equipment - Normally Primary below 50 kV													
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%									
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%									
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%									
1825	Storage Battery Equipment													
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%									
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%									
1830	Poles, Towers and Fixtures													
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%									
1830-4	Poles, Towers and Fixtures - Primary	100%	65%	35%	100%									
1830-5	Poles, Towers and Fixtures - Secondary	100%	65%	35%	100%									
1835	Overhead Conductors and Devices													
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%									

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1835-4	Overhead Conductors and Devices - Primary	100%	65%	35%	100%									
1835-5	Overhead Conductors and Devices - Secondary	100%	65%	35%	100%									
1840	Underground Conduit													
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%									
1840-4	Underground Conduit - Primary	100%	65%	35%	100%									
1840-5	Underground Conduit - Secondary	100%	65%	35%	100%									
1845	Underground Conductors and Devices													
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%									
1845-4	Underground Conductors and Devices - Primary	100%	65%	35%	100%									
1845-5	Underground Conductors and Devices - Secondary	100%	65%	35%	100%									
1850	Line Transformers	100%	70%	30%	100%									
1855	Services	100%	0%	100%	100%									
1860	Meters	100%	0%	100%	100%									
General Plant														
1905	Land	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1906	Land Rights	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1908	Buildings and Fixtures	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1910	Leasehold Improvements	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1915	Office Furniture and Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1920	Computer Equipment - Hardware	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1925	Computer Software	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1930	Transportation Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1935	Stores Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1940	Tools, Shop and Garage Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1945	Measurement and Testing Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1950	Power Operated Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1955	Communication Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1960	Miscellaneous Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1970	Load Management Controls - Customer Premises	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1975	Load Management Controls - Utility Premises	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1980	System Supervisory Equipment	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
1990	Other Tangible Property	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
2005	Property Under Capital Leases	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%
2010	Electric Plant Purchased or Sold	100%				51%	14%	1%	21%	7%	3%	3%	1%	100%

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
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Sheet E1 Categorization Worksheet

Ontario

This worksheet details how Density is derived and how Costs are Categorized.

Density of Utility

Density	Number of Customers	kM of Lines
130	696267	5365

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	35%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	35%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	35%
1835	Overhead Conductors and Devices	DNCP	CCA	35%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	35%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	35%
1840	Underground Conduit	DNCP	CCA	35%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	35%
1840-5	Underground Conduit - Secondary	SNCP	CCS	35%
1845	Underground Conductors and Devices	DNCP	CCA	35%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	35%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	35%
1850	Line Transformers	LTNCP	CCLT	30%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5010	Load Dispatching	1815-1855 D	1815-1855 C	35%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	35%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	35%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	30%

5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	35%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	35%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	30%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	35%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	35%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	35%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	35%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	35%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	35%
5145	Maintenance of Underground Conduit	1840 D	1840 C	35%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	35%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	30%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E1 Categorization Worksheet

Ontario

This worksheet details how Density is derived and how Costs are Categorized.

Density of Utility

Density	Number of Customers	kM of Lines
165	883508	5365

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	35%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	35%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	35%
1835	Overhead Conductors and Devices	DNCP	CCA	35%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	35%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	35%
1840	Underground Conduit	DNCP	CCA	35%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	35%
1840-5	Underground Conduit - Secondary	SNCP	CCS	35%
1845	Underground Conductors and Devices	DNCP	CCA	35%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	35%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	35%
1850	Line Transformers	LTNCP	CCLT	30%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5010	Load Dispatching	1815-1855 D	1815-1855 C	35%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	35%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	35%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	30%

5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	35%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	35%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	30%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	35%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	35%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	35%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	35%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	35%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	35%
5145	Maintenance of Underground Conduit	1840 D	1840 C	35%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	35%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	30%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E1 Categorization Worksheet

Ontario

This worksheet details how Density is derived and how Costs are Categorized.

Density of Utility

Density	Number of Customers	kM of Lines
171	918785	5365

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	35%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	35%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	35%
1835	Overhead Conductors and Devices	DNCP	CCA	35%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	35%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	35%
1840	Underground Conduit	DNCP	CCA	35%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	35%
1840-5	Underground Conduit - Secondary	SNCP	CCS	35%
1845	Underground Conductors and Devices	DNCP	CCA	35%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	35%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	35%
1850	Line Transformers	LTNCP	CCLT	30%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5010	Load Dispatching	1815-1855 D	1815-1855 C	35%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	35%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	35%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	30%

5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	35%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	35%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	30%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	35%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	35%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	35%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	35%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	35%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	35%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	35%
5145	Maintenance of Underground Conduit	1840 D	1840 C	35%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	35%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	30%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E2 Allocator Worksheet

Ontario

Details:
The worksheet below details how allocators are derived.

Explanation	ID and Factors	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Demand Allocators										
1 cp										
Transformation CP	TCP1	100.00%	25.40%	12.82%	5.63%	29.52%	18.03%	8.46%	0.00%	0.15%
Bulk Delivery (SubTransmission) CP	BCP1	100.00%	25.40%	12.82%	5.63%	29.52%	18.03%	8.46%	0.00%	0.15%
Distribution CP (Total System)	DCP1	100.00%	25.40%	12.82%	5.63%	29.52%	18.03%	8.46%	0.00%	0.15%
4 cp										
Transformation CP	TCP4	100.00%	26.12%	11.96%	5.94%	29.68%	17.70%	8.30%	0.14%	0.16%
Bulk Delivery (SubTransmission) CP	BCP4	100.00%	26.12%	11.96%	5.94%	29.68%	17.70%	8.30%	0.14%	0.16%
Distribution CP (Total System)	DCP4	100.00%	26.12%	11.96%	5.94%	29.68%	17.70%	8.30%	0.14%	0.16%
12 cp										
Transformation CP	TCP12	100.00%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%
Distribution CP (Total System)	DCP12	100.00%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%
NON CO_INCIDENT PEAK										
1 NCP										
Distribution NCP (Total System)	DNCP1	100.00%	23.74%	12.89%	6.50%	29.97%	18.14%	8.73%	0.00%	0.03%
Primary NCP	PNCP1	100.00%	23.74%	12.89%	6.50%	29.98%	18.14%	8.73%	0.00%	0.02%
Line Transformer NCP	LTNCP1	100.00%	33.62%	18.25%	7.68%	33.55%	6.26%	0.60%	0.00%	0.03%
Secondary NCP	SNCP1	100.00%	51.80%	28.13%	3.55%	15.51%	0.96%	0.00%	0.00%	0.04%

4 NCP										
Distribution NCP (Total System)	DNCP4	100.00%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%
Primary NCP	PNCP4	100.00%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%
Line Transformer NCP	LTNCP4	100.00%	33.16%	17.81%	7.96%	34.07%	6.36%	0.61%	0.00%	0.03%
Secondary NCP	SNCP4	100.00%	51.61%	27.72%	3.72%	15.91%	0.99%	0.00%	0.00%	0.05%
12 NCP										
Distribution NCP (Total System)	DNCP12	100.00%	22.14%	12.04%	6.32%	31.31%	19.06%	9.12%	0.00%	0.01%
Primary NCP	PNCP12	100.00%	22.14%	12.04%	6.32%	31.31%	19.06%	9.12%	0.00%	0.01%
Line Transformer NCP	LTNCP12	100.00%	31.94%	17.37%	7.61%	35.72%	6.70%	0.64%	0.00%	0.02%
Secondary NCP	SNCP12	100.00%	50.70%	27.58%	3.62%	17.01%	1.06%	0.00%	0.00%	0.03%
Demand Allocators - Composite										
DEMAND 1815-1855	1815-1855 D	100.00%	31.80%	17.07%	6.33%	28.02%	11.76%	4.99%	0.00%	0.03%
DEMAND 1808	1808 D	100.00%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%
DEMAND 1815	1815 D	100.00%	25.01%	10.99%	5.66%	31.07%	18.15%	8.55%	0.39%	0.18%
DEMAND 1820	1820 D	100.00%	23.31%	12.52%	6.70%	30.29%	18.34%	8.82%	0.00%	0.02%
DEMAND 1815 & 1820	1815 & 1820 D	100.00%	23.45%	12.39%	6.62%	30.36%	18.32%	8.79%	0.03%	0.04%
DEMAND 1830	1830 D	100.00%	36.61%	19.67%	5.30%	23.53%	10.18%	4.67%	0.00%	0.04%
DEMAND 1835	1835 D	100.00%	36.61%	19.67%	5.30%	23.53%	10.18%	4.67%	0.00%	0.04%
DEMAND 1830 & 1835	1830 & 1835 D	100.00%	36.61%	19.67%	5.30%	23.53%	10.18%	4.67%	0.00%	0.04%
DEMAND 1840	1840 D	100.00%	30.74%	16.51%	5.92%	26.52%	13.78%	6.50%	0.00%	0.03%
DEMAND 1845	1845 D	100.00%	30.74%	16.51%	5.92%	26.52%	13.78%	6.50%	0.00%	0.03%
DEMAND 1840 & 1845	1840 & 1845 D	100.00%	30.74%	16.51%	5.92%	26.52%	13.78%	6.50%	0.00%	0.03%
DEMAND 1850	1850 D	100.00%	33.16%	17.81%	7.96%	34.07%	6.36%	0.61%	0.00%	0.03%
DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER ALLOCATORS										
Billing Data										
kWh	CEN	100.00%	21.34%	9.99%	5.30%	32.93%	19.74%	10.05%	0.43%	0.22%
kW	CDEM	100.00%	0.00%	0.00%	8.74%	50.99%	27.04%	12.50%	0.73%	0.00%
kWh - Excl WMP	CEN EWMP	100.00%	21.53%	10.08%	5.34%	33.22%	19.92%	9.25%	0.43%	0.23%
Dollar Billed (per 2006 EDR)	CREV	100.00%	39.17%	13.62%	4.40%	25.47%	12.01%	4.70%	0.37%	0.26%
Bad Debt 3 Year Historical Average	BDHA	100.00%	56.19%	26.88%	11.45%	1.88%	3.59%	0.00%	0.00%	0.00%
Late Payment 3 Year Historical Average	LPHA	100.00%	54.81%	22.02%	14.70%	3.85%	3.95%	0.66%	0.00%	0.00%

Number of Bills	CNB	100.00%	79.59%	17.26%	0.55%	2.44%	0.14%	0.01%	0.00%	0.00%
Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	83.37%	16.63%
Total Number of Customer	CCA	100.00%	76.88%	8.34%	0.27%	1.18%	0.07%	0.01%	11.06%	2.21%
Subtransmission Customer Base	CCB	-	0	0	0	0	0	0	0	0
Primary Feeder Customer Base	CCP	100.00%	76.88%	8.34%	0.27%	1.18%	0.07%	0.01%	11.06%	2.21%
Line Transformer Customer Base	CCLT	100.00%	77.14%	8.37%	0.22%	0.93%	0.02%	0.00%	11.10%	2.22%
Secondary Feeder Customer Base	CCS	100.00%	77.79%	8.44%	0.07%	0.28%	0.00%	0.00%	11.19%	2.23%
Weighted - Services	CWCS	100.00%	69.70%	15.12%	0.60%	2.53%	0.01%	0.00%	10.03%	2.00%
Weighted Meter -Capital	CWMC	100.00%	67.57%	8.31%	2.35%	18.52%	2.92%	0.32%	0.00%	0.00%
Weighted Meter Reading	CWMR	100.00%	71.46%	27.65%	0.90%	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Bills	CWNB	100.00%	58.44%	25.35%	2.83%	12.53%	0.70%	0.14%	0.00%	0.01%
CUSTOMER ALLOCATORS - Composite										
CUSTOMER 1815-1855	1815-1855 C	100.00%	74.59%	10.17%	0.37%	1.67%	0.24%	0.11%	10.71%	2.14%
CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1820	1820 C	100.00%	21.34%	9.99%	5.30%	32.93%	19.74%	10.05%	0.43%	0.22%
CUSTOMER 1815 & 1820	1815 & 1820 C	100.00%	21.34%	9.99%	5.30%	32.93%	19.74%	10.05%	0.43%	0.22%
CUSTOMER 1830	1830 C	100.00%	77.30%	8.38%	0.17%	0.76%	0.04%	0.00%	11.12%	2.22%
CUSTOMER 1835	1835 C	100.00%	77.30%	8.38%	0.17%	0.76%	0.04%	0.00%	11.12%	2.22%
CUSTOMER 1830 & 1835	1830 & 1835 C	100.00%	77.30%	8.38%	0.17%	0.76%	0.04%	0.00%	11.12%	2.22%
CUSTOMER 1840	1840 C	100.00%	77.12%	8.36%	0.21%	0.94%	0.05%	0.00%	11.10%	2.21%
CUSTOMER 1845	1845 C	100.00%	77.12%	8.36%	0.21%	0.94%	0.05%	0.00%	11.10%	2.21%
CUSTOMER 1840 & 1845	1840 & 1845 C	100.00%	77.12%	8.36%	0.21%	0.94%	0.05%	0.00%	11.10%	2.21%
CUSTOMER 1850	1850 C	100.00%	77.14%	8.37%	0.22%	0.93%	0.02%	0.00%	11.10%	2.22%
CUSTOMER 1855	1855 C	100.00%	69.70%	15.12%	0.60%	2.53%	0.01%	0.00%	10.03%	2.00%
CUSTOMER 1860	1860 C	100.00%	67.57%	8.31%	2.35%	18.52%	2.92%	0.32%	0.00%	0.00%
Composite Allocators										
Net Fixed Assets	NFA	100.00%	49.02%	13.74%	3.91%	18.07%	7.48%	3.19%	3.82%	0.78%
Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	49.03%	13.92%	3.96%	18.18%	7.28%	3.05%	3.81%	0.78%
5005-5340	O&M	100.00%	48.23%	16.57%	4.26%	17.73%	7.40%	3.19%	2.17%	0.46%

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E2 Allocator Worksheet - First Run

Ontario

Details:
The worksheet below details how allocators are derived.

Explanation	ID and Factors	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Demand Allocators										
1 cp										
Transformation CP	TCP1	100.00%	27.35%	12.00%	2.80%	31.26%	18.00%	8.43%	0.00%	0.15%
Bulk Delivery (SubTransmission) CP	BCP1	100.00%	27.35%	12.00%	2.80%	31.26%	18.00%	8.43%	0.00%	0.15%
Distribution CP (Total System)	DCP1	100.00%	27.35%	12.00%	2.80%	31.26%	18.00%	8.43%	0.00%	0.15%
4 cp										
Transformation CP	TCP4	100.00%	27.87%	11.27%	3.06%	31.57%	17.64%	8.28%	0.15%	0.16%
Bulk Delivery (SubTransmission) CP	BCP4	100.00%	27.87%	11.27%	3.06%	31.57%	17.64%	8.28%	0.15%	0.16%
Distribution CP (Total System)	DCP4	100.00%	27.87%	11.27%	3.06%	31.57%	17.64%	8.28%	0.15%	0.16%
12 cp										
Transformation CP	TCP12	100.00%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%
Distribution CP (Total System)	DCP12	100.00%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%
NON CO_INCIDENT PEAK										
1 NCP										
Distribution NCP (Total System)	DNCP1	100.00%	25.05%	12.08%	3.90%	31.92%	18.23%	8.74%	0.00%	0.08%
Primary NCP	PNCP1	100.00%	25.05%	12.08%	3.90%	31.92%	18.23%	8.74%	0.00%	0.07%
Line Transformer NCP	LTNCP1	100.00%	35.43%	17.08%	4.62%	35.89%	6.28%	0.60%	0.00%	0.10%
Secondary NCP	SNCP1	100.00%	54.18%	26.13%	2.12%	16.47%	0.96%	0.00%	0.00%	0.15%

4 NCP										
Distribution NCP (Total System)	DNCP4	100.00%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%
Primary NCP	PNCP4	100.00%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%
Line Transformer NCP	LTNCP4	100.00%	34.71%	16.80%	4.65%	36.72%	6.40%	0.61%	0.00%	0.11%
Secondary NCP	SNCP4	100.00%	53.67%	25.98%	2.16%	17.03%	0.99%	0.00%	0.00%	0.16%
12 NCP										
Distribution NCP (Total System)	DNCP12	100.00%	23.04%	11.59%	3.25%	33.67%	19.20%	9.18%	0.00%	0.07%
Primary NCP	PNCP12	100.00%	23.04%	11.59%	3.25%	33.67%	19.20%	9.18%	0.00%	0.07%
Line Transformer NCP	LTNCP12	100.00%	33.25%	16.72%	3.92%	38.62%	6.75%	0.64%	0.00%	0.09%
Secondary NCP	SNCP12	100.00%	52.36%	26.33%	1.85%	18.25%	1.06%	0.00%	0.00%	0.15%
Demand Allocators - Composite										
DEMAND 1815-1855	1815-1855 D	100.00%	33.17%	16.03%	3.69%	30.11%	11.87%	5.02%	0.00%	0.10%
DEMAND 1808	1808 D	100.00%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%
DEMAND 1815	1815 D	100.00%	26.68%	10.49%	2.83%	32.92%	17.96%	8.56%	0.38%	0.18%
DEMAND 1820	1820 D	100.00%	24.41%	11.82%	3.91%	32.47%	18.46%	8.86%	0.00%	0.07%
DEMAND 1815 & 1820	1815 & 1820 D	100.00%	24.68%	11.66%	3.78%	32.53%	18.40%	8.82%	0.05%	0.09%
DEMAND 1830	1830 D	100.00%	38.17%	18.48%	3.09%	25.21%	10.24%	4.69%	0.00%	0.12%
DEMAND 1835	1835 D	100.00%	38.17%	18.48%	3.09%	25.21%	10.24%	4.69%	0.00%	0.12%
DEMAND 1830 & 1835	1830 & 1835 D	100.00%	38.17%	18.48%	3.09%	25.21%	10.24%	4.69%	0.00%	0.12%
DEMAND 1840	1840 D	100.00%	32.09%	15.54%	3.45%	28.42%	13.87%	6.53%	0.00%	0.10%
DEMAND 1845	1845 D	100.00%	32.09%	15.54%	3.45%	28.42%	13.87%	6.53%	0.00%	0.10%
DEMAND 1840 & 1845	1840 & 1845 D	100.00%	32.09%	15.54%	3.45%	28.42%	13.87%	6.53%	0.00%	0.10%
DEMAND 1850	1850 D	100.00%	34.71%	16.80%	4.65%	36.72%	6.40%	0.61%	0.00%	0.11%
DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER ALLOCATORS										
Billing Data										
kWh	CEN	100.00%	21.78%	9.99%	2.57%	35.16%	19.77%	10.08%	0.43%	0.23%
kW	CDEM	100.00%	0.00%	0.00%	4.24%	55.21%	27.22%	12.59%	0.73%	0.00%
kWh - Excl WMP	CEN EWMP	100.00%	21.98%	10.08%	2.59%	35.48%	19.94%	9.27%	0.43%	0.23%
Dollar Billed (per 2006 EDR)	CREV	100.00%	41.46%	13.61%	2.06%	25.86%	11.32%	4.56%	0.79%	0.33%
Bad Debt 3 Year Historical Average	BDHA	100.00%	56.19%	26.88%	11.45%	1.88%	3.59%	0.00%	0.00%	0.00%
Late Payment 3 Year Historical Average	LPHA	100.00%	54.81%	22.02%	14.70%	3.85%	3.95%	0.66%	0.00%	0.00%

Number of Bills	CNB	100.00%	80.29%	16.66%	0.27%	2.63%	0.13%	0.01%	0.00%	0.00%
Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	87.60%	12.40%
Total Number of Customer	CCA	100.00%	78.13%	8.11%	0.13%	1.28%	0.06%	0.01%	10.76%	1.52%
Subtransmission Customer Base	CCB	-	0	0	0	0	0	0	0	0
Primary Feeder Customer Base	CCP	100.00%	78.13%	8.11%	0.13%	1.28%	0.06%	0.01%	10.76%	1.52%
Line Transformer Customer Base	CCLT	100.00%	78.39%	8.13%	0.11%	1.02%	0.02%	0.00%	10.80%	1.53%
Secondary Feeder Customer Base	CCS	100.00%	79.03%	8.20%	0.03%	0.31%	0.00%	0.00%	10.89%	1.54%
Weighted - Services	CWCS	100.00%	71.01%	14.74%	0.29%	2.77%	0.01%	0.00%	9.78%	1.38%
Weighted Meter -Capital	CWMC	100.00%	67.02%	9.80%	1.08%	19.06%	2.75%	0.30%	0.00%	0.00%
Weighted Meter Reading	CWMR	100.00%	72.56%	26.99%	0.45%	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Bills	CWNB	100.00%	59.48%	24.69%	1.38%	13.62%	0.69%	0.14%	0.00%	0.01%
CUSTOMER ALLOCATORS - Composite										
CUSTOMER 1815-1855	1815-1855 C	100.00%	75.57%	9.85%	0.19%	2.01%	0.36%	0.17%	10.37%	1.47%
CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1820	1820 C	100.00%	21.78%	9.99%	2.57%	35.16%	19.77%	10.08%	0.43%	0.23%
CUSTOMER 1815 & 1820	1815 & 1820 C	100.00%	21.78%	9.99%	2.57%	35.16%	19.77%	10.08%	0.43%	0.23%
CUSTOMER 1830	1830 C	100.00%	78.55%	8.15%	0.08%	0.82%	0.04%	0.00%	10.82%	1.53%
CUSTOMER 1835	1835 C	100.00%	78.55%	8.15%	0.08%	0.82%	0.04%	0.00%	10.82%	1.53%
CUSTOMER 1830 & 1835	1830 & 1835 C	100.00%	78.55%	8.15%	0.08%	0.82%	0.04%	0.00%	10.82%	1.53%
CUSTOMER 1840	1840 C	100.00%	78.36%	8.13%	0.10%	1.02%	0.05%	0.00%	10.80%	1.53%
CUSTOMER 1845	1845 C	100.00%	78.36%	8.13%	0.10%	1.02%	0.05%	0.00%	10.80%	1.53%
CUSTOMER 1840 & 1845	1840 & 1845 C	100.00%	78.36%	8.13%	0.10%	1.02%	0.05%	0.00%	10.80%	1.53%
CUSTOMER 1850	1850 C	100.00%	78.39%	8.13%	0.11%	1.02%	0.02%	0.00%	10.80%	1.53%
CUSTOMER 1855	1855 C	100.00%	71.01%	14.74%	0.29%	2.77%	0.01%	0.00%	9.78%	1.38%
CUSTOMER 1860	1860 C	100.00%	67.02%	9.80%	1.08%	19.06%	2.75%	0.30%	0.00%	0.00%
Composite Allocators										
Net Fixed Assets	NFA	100.00%	50.46%	13.01%	2.21%	19.60%	7.50%	3.18%	3.50%	0.55%
Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	50.45%	13.18%	2.25%	19.71%	7.30%	3.04%	3.51%	0.56%
5005-5340	O&M	100.00%	49.42%	15.90%	2.58%	19.04%	7.40%	3.19%	2.12%	0.35%

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E2 Allocator Worksheet

Ontario

Details:
The worksheet below details how allocators are derived.

Explanation	ID and Factors	Total	1 Residential	2 GS <50	3 GS>50 Non RIMS	4 GS> 50 RIMS	5 GS >50-Intermediate	6 Large Use >5MW	7 Street Light	9 Unmetered Scattered Load
Demand Allocators										
1 cp										
Transformation CP	TCP1	100.00%	27.93%	13.02%	0.61%	32.03%	17.89%	8.38%	0.00%	0.15%
Bulk Delivery (SubTransmission) CP	BCP1	100.00%	27.93%	13.02%	0.61%	32.03%	17.89%	8.38%	0.00%	0.15%
Distribution CP (Total System)	DCP1	100.00%	27.93%	13.02%	0.61%	32.03%	17.89%	8.38%	0.00%	0.15%
4 cp										
Transformation CP	TCP4	100.00%	28.51%	12.11%	0.74%	32.60%	17.52%	8.23%	0.14%	0.16%
Bulk Delivery (SubTransmission) CP	BCP4	100.00%	28.51%	12.11%	0.74%	32.60%	17.52%	8.23%	0.14%	0.16%
Distribution CP (Total System)	DCP4	100.00%	28.51%	12.11%	0.74%	32.60%	17.52%	8.23%	0.14%	0.16%
12 cp										
Transformation CP	TCP12	100.00%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%
Distribution CP (Total System)	DCP12	100.00%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%
NON CO_INCIDENT PEAK										
1 NCP										
Distribution NCP (Total System)	DNCP1	100.00%	25.63%	13.45%	1.20%	32.63%	18.27%	8.74%	0.00%	0.07%
Primary NCP	PNCP1	100.00%	25.64%	13.45%	1.20%	32.63%	18.28%	8.74%	0.00%	0.06%
Line Transformer NCP	LTNCP1	100.00%	36.06%	18.92%	1.42%	36.66%	6.26%	0.60%	0.00%	0.09%
Secondary NCP	SNCP1	100.00%	53.73%	28.19%	0.63%	16.38%	0.93%	0.00%	0.00%	0.14%

4 NCP										
Distribution NCP (Total System)	DNCP4	100.00%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%
Primary NCP	PNCP4	100.00%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%
Line Transformer NCP	LTNCP4	100.00%	35.13%	18.08%	1.35%	38.32%	6.40%	0.61%	0.00%	0.10%
Secondary NCP	SNCP4	100.00%	53.35%	27.45%	0.62%	17.46%	0.97%	0.00%	0.00%	0.16%
12 NCP										
Distribution NCP (Total System)	DNCP12	100.00%	23.68%	12.44%	0.74%	34.75%	19.15%	9.18%	0.00%	0.07%
Primary NCP	PNCP12	100.00%	23.68%	12.44%	0.74%	34.75%	19.15%	9.18%	0.00%	0.07%
Line Transformer NCP	LTNCP12	100.00%	33.99%	17.85%	0.89%	39.83%	6.70%	0.64%	0.00%	0.09%
Secondary NCP	SNCP12	100.00%	52.44%	27.54%	0.41%	18.43%	1.03%	0.00%	0.00%	0.14%
Demand Allocators - Composite										
DEMAND 1815-1855	1815-1855 D	100.00%	33.34%	17.10%	1.06%	31.36%	11.96%	5.08%	0.01%	0.10%
DEMAND 1808	1808 D	100.00%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%
DEMAND 1815	1815 D	100.00%	27.40%	10.93%	0.65%	34.11%	17.93%	8.42%	0.39%	0.18%
DEMAND 1820	1820 D	100.00%	24.78%	12.75%	1.14%	33.84%	18.52%	8.90%	0.00%	0.07%
DEMAND 1815 & 1820	1815 & 1820 D	100.00%	25.25%	12.42%	1.05%	33.89%	18.41%	8.81%	0.07%	0.09%
DEMAND 1830	1830 D	100.00%	38.21%	19.66%	0.89%	26.14%	10.27%	4.71%	0.00%	0.11%
DEMAND 1835	1835 D	100.00%	38.21%	19.66%	0.89%	26.14%	10.27%	4.71%	0.00%	0.11%
DEMAND 1830 & 1835	1830 & 1835 D	100.00%	38.21%	19.66%	0.89%	26.14%	10.27%	4.71%	0.00%	0.11%
DEMAND 1840	1840 D	100.00%	32.28%	16.61%	1.00%	29.54%	13.91%	6.56%	0.00%	0.10%
DEMAND 1845	1845 D	100.00%	32.28%	16.61%	1.00%	29.54%	13.91%	6.56%	0.00%	0.10%
DEMAND 1840 & 1845	1840 & 1845 D	100.00%	32.28%	16.61%	1.00%	29.54%	13.91%	6.56%	0.00%	0.10%
DEMAND 1850	1850 D	100.00%	35.13%	18.08%	1.35%	38.32%	6.40%	0.61%	0.00%	0.10%
DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER ALLOCATORS										
Billing Data										
kWh	CEN	100.00%	22.44%	9.98%	0.59%	36.47%	19.78%	10.09%	0.43%	0.23%
kW	CDEM	100.00%	0.00%	0.00%	0.97%	58.11%	27.47%	12.70%	0.74%	0.00%
kWh - Excl WMP	CEN EWMP	100.00%	21.41%	10.26%	24.16%	14.35%	19.88%	9.30%	0.43%	0.21%
Dollar Billed (per 2006 EDR)	CREV	100.00%	43.41%	13.38%	0.46%	26.07%	10.93%	4.46%	0.94%	0.36%
Bad Debt 3 Year Historical Average	BDHA	100.00%	56.19%	26.88%	11.45%	1.88%	3.59%	0.00%	0.00%	0.00%
Late Payment 3 Year Historical Average	LPHA	100.00%	54.81%	22.02%	14.70%	3.85%	3.95%	0.66%	0.00%	0.00%

Number of Bills	CNB	100.00%	81.14%	15.95%	0.06%	2.70%	0.13%	0.01%	0.00%	0.00%
Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	87.60%	12.40%
Total Number of Customer	CCA	100.00%	79.03%	7.77%	0.03%	1.32%	0.06%	0.01%	10.32%	1.46%
Subtransmission Customer Base	CCB	-	0	0	0	0	0	0	0	0
Primary Feeder Customer Base	CCP	100.00%	79.03%	7.77%	0.03%	1.32%	0.06%	0.01%	10.32%	1.46%
Line Transformer Customer Base	CCLT	100.00%	79.29%	7.79%	0.03%	1.05%	0.02%	0.00%	10.36%	1.47%
Secondary Feeder Customer Base	CCS	100.00%	79.90%	7.85%	0.01%	0.32%	0.00%	0.00%	10.44%	1.48%
Weighted - Services	CWCS	100.00%	72.11%	14.17%	0.07%	2.88%	0.01%	0.00%	9.42%	1.33%
Weighted Meter -Capital	CWMC	100.00%	67.66%	9.62%	0.26%	19.54%	2.65%	0.28%	0.00%	0.00%
Weighted Meter Reading	CWMR	100.00%	73.75%	26.13%	0.12%	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Bills	CWNB	100.00%	60.78%	23.90%	0.33%	14.17%	0.68%	0.13%	0.00%	0.01%
CUSTOMER ALLOCATORS - Composite										
CUSTOMER 1815-1855	1815-1855 C	100.00%	76.37%	9.42%	0.05%	2.19%	0.43%	0.21%	9.93%	1.41%
CUSTOMER 1808	1808 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815	1815 C	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1820	1820 C	100.00%	22.44%	9.98%	0.59%	36.47%	19.78%	10.09%	0.43%	0.23%
CUSTOMER 1815 & 1820	1815 & 1820 C	100.00%	22.44%	9.98%	0.59%	36.47%	19.78%	10.09%	0.43%	0.23%
CUSTOMER 1830	1830 C	100.00%	79.44%	7.81%	0.02%	0.85%	0.03%	0.00%	10.38%	1.47%
CUSTOMER 1835	1835 C	100.00%	79.44%	7.81%	0.02%	0.85%	0.03%	0.00%	10.38%	1.47%
CUSTOMER 1830 & 1835	1830 & 1835 C	100.00%	79.44%	7.81%	0.02%	0.85%	0.03%	0.00%	10.38%	1.47%
CUSTOMER 1840	1840 C	100.00%	79.26%	7.79%	0.02%	1.05%	0.05%	0.00%	10.35%	1.47%
CUSTOMER 1845	1845 C	100.00%	79.26%	7.79%	0.02%	1.05%	0.05%	0.00%	10.35%	1.47%
CUSTOMER 1840 & 1845	1840 & 1845 C	100.00%	79.26%	7.79%	0.02%	1.05%	0.05%	0.00%	10.35%	1.47%
CUSTOMER 1850	1850 C	100.00%	79.29%	7.79%	0.03%	1.05%	0.02%	0.00%	10.36%	1.47%
CUSTOMER 1855	1855 C	100.00%	72.11%	14.17%	0.07%	2.88%	0.01%	0.00%	9.42%	1.33%
CUSTOMER 1860	1860 C	100.00%	67.66%	9.62%	0.26%	19.54%	2.65%	0.28%	0.00%	0.00%
Composite Allocators										
Net Fixed Assets	NFA	100.00%	50.71%	13.35%	0.63%	20.63%	7.65%	3.25%	3.25%	0.52%
Net Fixed Assets Excluding Capital Contribution	NFA ECC	100.00%	50.73%	13.57%	0.64%	20.73%	7.43%	3.10%	3.28%	0.52%
5005-5340	O&M	100.00%	50.25%	15.93%	1.08%	19.77%	7.39%	3.17%	2.07%	0.35%

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E3 Demand Allocator Worksheet

Ontario

Instructions:
Input sheet for Demand Allocators.

PLCC WATTS
400

		1	2	3	4	5	6	7	9
Customer Classes	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
CCA	**802,787**	617,157	66,934	2,135	9,451	528	49	88,812	17,721
CCB	**-**	0	0	0	0	0	0	0	0
CCP	**802,787**	617,157	66,934	2,135	9,451	528	49	88,812	17,721
CCLT	**800,009**	617,157	66,934	1,783	7,471	129	3	88,812	17,721
CCS	**793,413**	617,157	66,934	535	2,241	13	0	88,812	17,721
PLCC-CCA	**321,115**	246,863	26,774	854	3,780	211	20	35,525	7,088
PLCC-CCB	**-**	0	0	0	0	0	0	0	0
PLCC-CCP	**321,115**	246,863	26,774	854	3,780	211	20	35,525	7,088
PLCC-CCLT	**320,004**	246,863	26,774	713	2,988	51	1	35,525	7,088
PLCC-CCS	**317,365**	246,863	26,774	214	897	5	0	35,525	7,088
1NCP									
DNCP1	**4,745,625**	1,299,109	598,172	288,919	1,332,383	804,294	386,774	27,553	8,421
PNCP1	**4,745,188**	1,299,109	598,172	288,919	1,332,383	804,294	386,774	27,553	7,984
LTNCP1	**3,442,125**	1,299,109	598,172	241,247	1,053,274	195,973	18,813	27,553	7,984
SNCP1	**2,340,772**	1,299,109	598,172	72,374	315,982	19,597	0	27,553	7,984
PLCC - 1NCP									
DNCP1A	**4,432,482**	1,052,246	571,398	288,065	1,328,602	804,083	386,755	0	1,333
PNCP1A	**4,432,045**	1,052,246	571,398	288,065	1,328,602	804,083	386,755	0	896
LTNCP1A	**3,130,094**	1,052,246	571,398	240,534	1,050,285	195,922	18,812	0	896
SNCP1A	**2,031,378**	1,052,246	571,398	72,160	315,086	19,592	0	0	896

4 NCP									
DNCP4	**18,219,018**	4,941,942	2,231,319	1,140,368	5,155,375	3,112,728	1,496,059	108,701	32,526
PNCP4	**18,219,018**	4,941,942	2,231,319	1,140,368	5,155,375	3,112,728	1,496,059	108,701	32,526
LTNCP4	**13,173,330**	4,941,942	2,231,319	952,206	4,075,422	758,444	72,770	108,701	32,526
SNCP4	**8,898,621**	4,941,942	2,231,319	285,662	1,222,627	75,844	0	108,701	32,526
PLCC - 4NCP									
DNCP4A	**16,967,957**	3,954,491	2,124,225	1,136,952	5,140,253	3,111,883	1,495,980	0	4,172
PNCP4A	**16,967,957**	3,954,491	2,124,225	1,136,952	5,140,253	3,111,883	1,495,980	0	4,172
LTNCP4A	**11,926,713**	3,954,491	2,124,225	949,354	4,063,468	758,238	72,765	0	4,172
SNCP4A	**7,662,558**	3,954,491	2,124,225	284,806	1,219,040	75,824	0	0	4,172
12NCP									
DNCP12	**50,393,418**	13,291,231	5,939,051	2,956,589	14,654,812	8,893,989	4,254,770	312,571	90,404
PNCP12	**50,393,418**	13,291,231	5,939,051	2,956,589	14,654,812	8,893,989	4,254,770	312,571	90,404
LTNCP12	**36,060,969**	13,291,231	5,939,051	2,468,748	11,584,908	2,167,099	206,957	312,571	90,404
SNCP12	**24,066,063**	13,291,231	5,939,051	740,624	3,475,472	216,710	0	312,571	90,404
PLCC - 12NCP									
DNCP12A	**46,653,767**	10,328,877	5,617,768	2,946,341	14,609,447	8,891,455	4,254,535	0	5,343
PNCP12A	**46,653,767**	10,328,877	5,617,768	2,946,341	14,609,447	8,891,455	4,254,535	0	5,343
LTNCP12A	**32,334,649**	10,328,877	5,617,768	2,460,191	11,549,046	2,166,481	206,943	0	5,343
SNCP12A	**20,371,407**	10,328,877	5,617,768	738,057	3,464,714	216,648	0	0	5,343

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E3 Demand Allocator Worksheet

Ontario

Instructions:
Input sheet for Demand Allocators.

PLCC WATTS
400

		1	2	3	4	5	6	7	9
Customer Classes	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
CCA	**825,015**	644,567	66,878	1,065	10,540	536	49	88,812	12,568
CCB	**-**	0	0	0	0	0	0	0	0
CCP	**825,015**	644,567	66,878	1,065	10,540	536	49	88,812	12,568
CCLT	**822,229**	644,567	66,878	890	8,380	131	3	88,812	12,568
CCS	**815,619**	644,567	66,878	267	2,514	13	0	88,812	12,568
PLCC-CCA	**330,006**	257,827	26,751	426	4,216	214	20	35,525	5,027
PLCC-CCB	**-**	0	0	0	0	0	0	0	0
PLCC-CCP	**330,006**	257,827	26,751	426	4,216	214	20	35,525	5,027
PLCC-CCLT	**328,891**	257,827	26,751	356	3,352	52	1	35,525	5,027
PLCC-CCS	**326,248**	257,827	26,751	107	1,006	5	0	35,525	5,027
1NCP									
DNCP1	**4,755,338**	1,368,225	562,196	173,463	1,419,215	808,429	387,593	27,716	8,502
PNCP1	**4,754,898**	1,368,225	562,196	173,463	1,419,215	808,429	387,593	27,716	8,061
LTNCP1	**3,455,415**	1,368,225	562,196	145,033	1,128,352	196,977	18,855	27,716	8,061
SNCP1	**2,367,911**	1,368,225	562,196	43,510	338,506	19,698	0	27,716	8,061
PLCC - 1NCP									
DNCP1A	**4,433,141**	1,110,399	535,444	173,037	1,414,999	808,215	387,573	0	3,474
PNCP1A	**4,432,700**	1,110,399	535,444	173,037	1,414,999	808,215	387,573	0	3,034
LTNCP1A	**3,134,332**	1,110,399	535,444	144,676	1,125,001	196,925	18,854	0	3,034
SNCP1A	**2,049,472**	1,110,399	535,444	43,403	337,500	19,692	0	0	3,034

4 NCP									
DNCP4	**18,213,615**	5,163,024	2,107,149	663,704	5,513,664	3,124,834	1,499,278	109,294	32,668
PNCP4	**18,213,615**	5,163,024	2,107,149	663,704	5,513,664	3,124,834	1,499,278	109,294	32,668
LTNCP4	**13,185,033**	5,163,024	2,107,149	554,925	4,383,660	761,379	72,935	109,294	32,668
SNCP4	**8,969,848**	5,163,024	2,107,149	166,478	1,315,098	76,138	0	109,294	32,668
PLCC - 4NCP									
DNCP4A	**16,926,396**	4,131,717	2,000,144	662,000	5,496,800	3,123,977	1,499,199	0	12,559
PNCP4A	**16,926,396**	4,131,717	2,000,144	662,000	5,496,800	3,123,977	1,499,199	0	12,559
LTNCP4A	**11,902,272**	4,131,717	2,000,144	553,500	4,370,252	761,170	72,930	0	12,559
SNCP4A	**7,697,663**	4,131,717	2,000,144	166,050	1,311,076	76,117	0	0	12,559
12NCP									
DNCP12	**50,402,015**	13,822,064	5,715,942	1,519,141	15,724,136	8,942,626	4,272,439	314,779	90,888
PNCP12	**50,402,015**	13,822,064	5,715,942	1,519,141	15,724,136	8,942,626	4,272,439	314,779	90,888
LTNCP12	**36,102,114**	13,822,064	5,715,942	1,270,159	12,501,536	2,178,907	207,840	314,779	90,888
SNCP12	**24,293,072**	13,822,064	5,715,942	381,048	3,750,461	217,891	0	314,779	90,888
PLCC - 12NCP									
DNCP12A	**46,553,461**	10,728,142	5,394,928	1,514,029	15,673,544	8,940,053	4,272,203	0	30,561
PNCP12A	**46,553,461**	10,728,142	5,394,928	1,514,029	15,673,544	8,940,053	4,272,203	0	30,561
LTNCP12A	**32,266,934**	10,728,142	5,394,928	1,265,884	12,461,312	2,178,281	207,825	0	30,561
SNCP12A	**20,489,618**	10,728,142	5,394,928	379,765	3,738,394	217,828	0	0	30,561

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E3 Demand Allocator Worksheet

Ontario

Instructions:
Input sheet for Demand Allocators.

PLCC WATTS
400

		1	2	3	4	5	6	7	9
Customer Classes	**Total**	**Residential**	**GS <50**	**GS>50 Non RIMS**	**GS> 50 RIMS**	**GS >50-Intermediate**	**Large Use >5MW**	**Street Light**	**Unmetered Scattered Load**
CCA	**860,292**	679,914	66,823	265	11,318	543	49	88,812	12,568
CCB	**-**	0	0	0	0	0	0	0	0
CCP	**860,292**	679,914	66,823	265	11,318	543	49	88,812	12,568
CCLT	**857,513**	679,914	66,823	222	9,039	132	3	88,812	12,568
CCS	**850,909**	679,914	66,823	67	2,712	13	0	88,812	12,568
PLCC-CCA	**344,117**	271,966	26,729	106	4,527	217	20	35,525	5,027
PLCC-CCB	**-**	0	0	0	0	0	0	0	0
PLCC-CCP	**344,117**	271,966	26,729	106	4,527	217	20	35,525	5,027
PLCC-CCLT	**343,005**	271,966	26,729	89	3,615	53	1	35,525	5,027
PLCC-CCS	**340,363**	271,966	26,729	27	1,085	5	0	35,525	5,027
1NCP									
DNCP1	**4,788,341**	1,413,300	625,514	53,541	1,457,332	813,818	389,027	27,468	8,340
PNCP1	**4,787,908**	1,413,300	625,514	53,541	1,457,332	813,818	389,027	27,468	7,908
LTNCP1	**3,500,133**	1,413,300	625,514	44,892	1,163,841	198,286	18,924	27,468	7,908
SNCP1	**2,456,639**	1,413,300	625,514	13,468	349,152	19,829	0	27,468	7,908
PLCC - 1NCP									
DNCP1A	**4,452,281**	1,141,335	598,785	53,435	1,452,805	813,601	389,007	0	3,313
PNCP1A	**4,451,848**	1,141,335	598,785	53,435	1,452,805	813,601	389,007	0	2,880
LTNCP1A	**3,165,185**	1,141,335	598,785	44,803	1,160,225	198,233	18,923	0	2,880

SNCP1A	**2,124,332**	1,141,335	598,785	13,441	348,068	19,823	0	0	2,880
4 NCP									
DNCP4	**18,300,148**	5,289,805	2,268,872	193,029	5,757,221	3,141,494	1,508,886	108,313	32,529
PNCP4	**18,300,148**	5,289,805	2,268,872	193,029	5,757,221	3,141,494	1,508,886	108,313	32,529
LTNCP4	**13,297,966**	5,289,805	2,268,872	161,849	4,597,777	765,420	73,401	108,313	32,529
SNCP4	**9,203,948**	5,289,805	2,268,872	48,555	1,379,333	76,542	0	108,313	32,529
PLCC - 4NCP									
DNCP4A	**16,957,468**	4,201,943	2,161,955	192,605	5,739,112	3,140,625	1,508,808	0	12,420
PNCP4A	**16,957,468**	4,201,943	2,161,955	192,605	5,739,112	3,140,625	1,508,808	0	12,420
LTNCP4A	**11,959,731**	4,201,943	2,161,955	161,493	4,583,315	765,209	73,396	0	12,420
SNCP4A	**7,876,281**	4,201,943	2,161,955	48,448	1,374,994	76,521	0	0	12,420
12NCP									
DNCP12	**50,438,590**	14,258,321	6,094,628	345,056	16,187,270	8,894,032	4,262,119	306,547	90,616
PNCP12	**50,438,590**	14,258,321	6,094,628	345,056	16,187,270	8,894,032	4,262,119	306,547	90,616
LTNCP12	**36,341,106**	14,258,321	6,094,628	289,319	12,927,323	2,167,018	207,334	306,547	90,616
SNCP12	**24,931,806**	14,258,321	6,094,628	86,796	3,878,197	216,702	0	306,547	90,616
PLCC - 12NCP									
DNCP12A	**46,428,938**	10,994,734	5,773,878	343,784	16,132,944	8,891,426	4,261,884	0	30,289
PNCP12A	**46,428,938**	10,994,734	5,773,878	343,784	16,132,944	8,891,426	4,261,884	0	30,289
LTNCP12A	**32,344,793**	10,994,734	5,773,878	288,253	12,883,937	2,166,383	207,319	0	30,289
SNCP12A	**20,967,196**	10,994,734	5,773,878	86,476	3,865,181	216,638	0	0	30,289

2008 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E4 Trial Balance Allocation Detail Worksheet

Ontario

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. FInally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					

1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC					
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC					
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC					
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC					
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC					
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
3046	Balance Transferred From Income	Equity	NI								NFA				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB				
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA				
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA				
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA				
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA				
4225	Late Payment Charges	Late Payment Charges	mi								LPHA				

4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA				
4305	Regulatory Debits	Other Income & Deductions	mi								NFA				
4310	Regulatory Credits	Other Income & Deductions	mi								NFA				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA				
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA				
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP					

4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN					
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP					
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN					
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C		830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C		840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC						
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA						

5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA						
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M					
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C					1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C					1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C					1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C					1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						

5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					

5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

2009 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limited
EB-2007-0680
Sheet E4 Trial Balance Allocation Detail Worksheet

Ontario

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. FInally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12

1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP											
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS						
1860	Meters	Services and Meters	dp			CWMC			CWMC						
1905	Land	Land and Buildings	gp							NFA ECC					
1906	Land Rights	Land and Buildings	gp							NFA ECC					
1908	Buildings and Fixtures	General Plant	gp							NFA ECC					
1910	Leasehold Improvements	General Plant	gp							NFA ECC					

1915	Office Furniture and Equipment	Equipment	gp							NFA ECC					
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC					
1925	Computer Software	IT Assets	gp							NFA ECC					
1930	Transportation Equipment	Equipment	gp							NFA ECC					
1935	Stores Equipment	Equipment	gp							NFA ECC					
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC					
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC					
1950	Power Operated Equipment	Equipment	gp							NFA ECC					
1955	Communication Equipment	Equipment	gp							NFA ECC					
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC					
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC					
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC					
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC					
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC					
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC					
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
3046	Balance Transferred From Income	Equity	NI								NFA				
4080	Distribution Services Revenue	Distribution Services Revenue	CREV								CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi								CWNB				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								CWNB				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								CWNB				
4205	Interdepartmental Rents	Other Distribution Revenue	mi								NFA				
4210	Rent from Electric Property	Other Distribution Revenue	mi								NFA				
4215	Other Utility Operating Income	Other Distribution Revenue	mi								NFA				
4220	Other Electric Revenues	Other Distribution Revenue	mi								NFA				
4225	Late Payment Charges	Late Payment Charges	mi								LPHA				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB				

4240	Provision for Rate Refunds	Other Distribution Revenue	mi								NFA					
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								NFA					
4305	Regulatory Debits	Other Income & Deductions	mi								NFA					
4310	Regulatory Credits	Other Income & Deductions	mi								NFA					
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								NFA					
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								NFA					
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								NFA					
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								NFA					
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								NFA					
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								NFA					
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA					
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								NFA					
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA					
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								NFA					
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA					
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								NFA					
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								NFA					
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								NFA					
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								NFA					
4405	Interest and Dividend Income	Other Income & Deductions	mi								NFA					
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								NFA					
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP						

4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN					
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP					
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN					
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP					
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C		830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C		840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC						
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA						
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA						
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D

5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M					
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C					1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C					1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C					1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C					1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR						
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						

5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB						
5405	Supervision	Community Relations (Working Capital)	ad							O&M					
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M					
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M					
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC					
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M					
5505	Supervision	Other Distribution Expenses	ad							O&M					
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M					
5515	Advertising Expense	Advertising Expenses	ad							O&M					
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M					
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M					
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M					
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC					
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M					
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M					
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M					
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5660	General Advertising Expenses	Advertising Expenses	ad							O&M					

5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M					
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M					
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M					
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M					
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC					
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M					
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M					
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M					
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA					
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA					
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA					
6205	Donations	Charitable Contributions	ad							O&M					
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M					
6215	Penalties	Other Distribution Expenses	ad							O&M					
6225	Other Deductions	Other Distribution Expenses	ad							O&M					

Ontario

2010 COST ALLOCATION STUDY
Toronto Hydro-Electric System Limit
EB-2007-0680
Sheet E4 Trial Balance Allocation Detail Worksheet

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. FInally, it will show how costs are being grouped together for presentation purposes.

			Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
CDM Expenditures and Recoveries	dp			O&M			O&M						
Other Distribution Assets	gp							NFA ECC					
	dp	DDCP											
	dp	TCP	TCP12			TCP12				TCP12			TCP12
	dp	DCP	DCP12			DCP12				DCP12			DCP12
	dp	DDCP											
	dp	TCP	TCP12			TCP12				TCP12			TCP12
	dp	DCP	DCP12			DCP12				DCP12			DCP12
	dp	DDCP											
	dp	TCP	TCP12			TCP12				TCP12			TCP12
	dp	DCP	DCP12			DCP12				DCP12			DCP12
	dp	DDCP											
	dp	TCP	TCP12			TCP12				TCP12			TCP12
	dp	DCP	DCP12			DCP12				DCP12			DCP12
	dp	TCP	TCP12			TCP12				TCP12			TCP12
	dp	DCP	DCP12			DCP12				DCP12			DCP12

	dp	DCP	DCP12			DCP12				DCP12			DCP12
	dp	PNCP	PNCP4			PNCP4					PNCP4		PNCP4
	dp			CEN			CEN						
	dp	DDCP											
	dp	TCP	TCP12			TCP12				TCP12			TCP12
	dp	DCP	DCP12			DCP12				DCP12			DCP12
	dp	DDNCP											
	dp	BCP	BCP12			BCP12				BCP12			BCP12
	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
	dp	DDNCP											
	dp	BCP	BCP12			BCP12				BCP12			BCP12
	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
	dp	DDNCP											
Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12
Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
Land and Buildings	dp	DDNCP											
TS Primary Above 50	dp	BCP	BCP12			BCP12				BCP12			BCP12
DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT				LTNCP4		LTNCP4
Services and Meters	dp			CWCS			CWCS						

Services and Meters	dp			CWMC			CWMC						
Land and Buildings	gp							NFA ECC					
Land and Buildings	gp							NFA ECC					
General Plant	gp							NFA ECC					
General Plant	gp							NFA ECC					
Equipment	gp							NFA ECC					
IT Assets	gp							NFA ECC					
IT Assets	gp							NFA ECC					
Equipment	gp							NFA ECC					
Equipment	gp							NFA ECC					
Equipment	gp							NFA ECC					
Equipment	gp							NFA ECC					
Equipment	gp							NFA ECC					
Equipment	gp							NFA ECC					
Equipment	gp							NFA ECC					
Other Distribution Assets	gp							NFA ECC					
Other Distribution Assets	gp							NFA ECC					
Other Distribution Assets	gp							NFA ECC					
Other Distribution Assets	gp							NFA ECC					
Contributions and Grants	co		Break out	Breakout		Break out	Breakout						
Other Distribution Assets	gp							NFA ECC					
Other Distribution Assets	gp							NFA ECC					
Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout						
Equity	NI								NFA				
Distribution Services Revenue	CREV								CREV				
Other Distribution Revenue	mi								CWNB				
Other Distribution Revenue	mi								CWNB				

Other Distribution Revenue	mi								CWNB				
Other Distribution Revenue	mi								NFA				
Other Distribution Revenue	mi								NFA				
Other Distribution Revenue	mi								NFA				
Other Distribution Revenue	mi								NFA				
Late Payment Charges	mi								LPHA				
Specific Service Charges	mi								CWNB				
Other Distribution Revenue	mi								NFA				
Other Distribution Revenue	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				

Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Other Income & Deductions	mi								NFA				
Power Supply Expenses (Working Capital)	cop							CEN EWMP					
Power Supply Expenses (Working Capital)	cop							CEN EWMP					
Power Supply Expenses (Working Capital)	cop							CEN EWMP					
Power Supply Expenses (Working Capital)	cop							CEN EWMP					
Power Supply Expenses (Working Capital)	cop							CEN					
Other Power Supply Expenses	cop							CEN EWMP					
Power Supply Expenses (Working Capital)	cop							CEN					
Power Supply Expenses (Working Capital)	cop							CEN EWMP					
Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D

Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C		830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C		840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
Operation (Working Capital)	cu			CWMC			CWMC						
Operation (Working Capital)	cu			CCA			CCA						
Operation (Working Capital)	cu			CCA			CCA						
Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	840 & 1845	1840 & 1845 C					1840 & 1845 D	1840 & 1845 D
Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
Operation (Working Capital)	di							O&M					
Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C					1815-1855 D	1815-1855 D
Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C					1808 D	1808 D
Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C					1815 D	1815 D
Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C					1820 D	1820 D
Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C					1830 D	1830 D
Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C					1835 D	1835 D
Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	830 & 1835	1830 & 1835 C					1830 & 1835 D	1830 & 1835 D
Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C					1840 D	1840 D

Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C					1845 D	1845 D
Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C					1855 D	1855 D
Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C					1850 D	1850 D
Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C					1860 D	1860 D
Billing and Collection (Working Capital)	cu			CWNB			CWNB						
Billing and Collection (Working Capital)	cu			CWMR			CWMR						
Billing and Collection (Working Capital)	cu			CWNB			CWNB						
Billing and Collection (Working Capital)	cu			CWNB			CWNB						
Billing and Collection (Working Capital)	cu			CWNB			CWNB						
Billing and Collection (Working Capital)	cu			CWNB			CWNB						
Bad Debt Expense (Working Capital)	cu			BDHA			BDHA						
Billing and Collection (Working Capital)	cu			CWNB			CWNB						
Community Relations (Working Capital)	ad							O&M					
Community Relations (Working Capital)	ad							O&M					
Community Relations - CDM (Working Capital)	ad							O&M					
Community Relations (Working Capital)	ad							NFA ECC					
Community Relations (Working Capital)	ad							O&M					
Other Distribution Expenses	ad							O&M					
Other Distribution Expenses	ad							O&M					
Advertising Expenses	ad							O&M					
Other Distribution Expenses	ad							O&M					

Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Insurance Expense (Working Capital)	ad							NFA ECC					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Advertising Expenses	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Administrative and General Expenses (Working Capital)	ad							O&M					
Power Supply Expenses (Working Capital)	cop							NFA ECC					
Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED

Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout					PRORATED	PRORATED
Amortization of Assets	dep							O&M					
Amortization of Assets	dep							O&M					
Amortization of Assets	dep							O&M					
Interest Expense - Unclassifed	INT							NFA					
Other Distribution Expenses	ad							NFA					
Income Tax Expense - Unclassified	Input							NFA					
Charitable Contributions	ad							O&M					
Insurance Expense (Working Capital)	ad							O&M					
Other Distribution Expenses	ad							O&M					
Other Distribution Expenses	ad							O&M					

RATE DESIGN

INTRODUCTION AND SUMMARY

The purpose of this evidence is to present the proposed rates designed to collect the requested revenue requirements in each of the test years. Distribution Rate schedules for the bridge year and test years are shown in Exhibit M1, Tab 2, Schedules 1-4. Exhibit O1 contains exhibits showing the bill impacts for different levels of energy/demand for each rate class.

The proposed rate changes primarily reflect THESL's increase in revenue requirement, the results of the OEB's Cost Allocation model, and consolidation of the GS>50-1000kW rate classes.

The proposed distribution rates for each rate class are summarized below in Table 1.

Table 1: Distribution Rates

	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
Residential					
Service Charge ($/30 days)	11.96	12	14.85	16.85	18.14
Volumetric Charge ($/kWh)	0.0154	0.0155	0.0173	0.0174	0.0177
General Service <50kW					
Service Charge ($/30 days)	16.02	16.07	19.37	21.44	22.84
Volumetric Charge ($/kWh)	0.0184	0.0185	0.021	0.0218	0.0227
General Service 50-1000kW					
Service Charge ($/30 days)	25.74	25.82	29.78	32.69	34.01
Volumetric Charge ($/kVA)	4.96	4.98	5.4	5.58	5.63
Intermediate 1000-5000kW					
Service Charge ($/30 days)	715.08	717.42	725.8	705.35	691.11
Volumetric Charge ($/kVA)	4.15	4.16	4.52	4.7	4.75
Large Use					
Service Charge ($/30 days)	2749.29	2758.3	2883.81	2639.04	2277.31
Volumetric Charge ($/kVA)	3.54	3.55	3.97	4.2	4.36
Streetlighting					
Connection Charge ($/connection/30 days)	0.26	0.26	0.66	0.89	1.12
Volumetric Charge ($/kVA)	3.59	3.6	8.75	10.82	13.12
Unmetered Scattered Load					
Service Charge ($/30 days)	1.98	1.99	2.96	3.42	3.74
Connection Charge ($/connection/30 days)	0.29	0.29	0.33	0.35	0.37
Volumetric Charge ($/kWh)	0.0179	0.018	0.0271	0.0312	0.0349

Notes:

Rates do not include any rate riders

GS 50-1000kW rates for 2006 and 2007 are for interval metered subclass

RATE DESIGN PROCESS

Generally accepted ratemaking principles guide the development of distribution rates. Those principles are best summarized by James Bonbright in his 1961 publication, *Principles of Public Utility Rates*. OEB Staff's March 30 draft discussion paper "Rate Design for Electricity Distributors: Overview and Scoping (EB-2007-0031)", cited these principles and summarized them as:

1) Practical - Rates should be simple to understand, accepted by the public, and feasible to implement.
2) Clear – Rates should have no ambiguity in their application.
3) Effective – Rates should recover the utility's revenue requirement.
4) Stable for the Utility – The utility should be able to recover its revenue requirement each year without excessive profits or losses.
5) Stable for Customers – Rates should be predictable enough for customers to make investment decisions.
6) Fair – To avoid cross subsidies, rates should follow the principle of cost causality; namely that those who cause the costs should pay them.
7) Promote efficient use of resources – Rates should discourage wasteful use of the system.
8) Avoid undue discrimination – Actions taken to fulfill the other principles must not cause undue discrimination against or in favour of a particular class or classes of customers.

These principles guided THESL in the development of rates for this application.

The principle of fairness means that costs of distribution are borne by those that cause THESL to incur the costs. The cost allocation exercise recently undertaken by the OEB (and described more fully in Exhibit L1) was an attempt to allocate costs to rate classes

for all provincial LDCs using a single model and on a consistent basis. The results of this exercise will be an input into the OEB's recently announced review of rate design (RP-2007-0031). THESL has chosen in this rate application to use the information contained in the cost allocation model – principally the resulting revenue-cost ratios for each rate class, as well as information on the monthly customer charge – to assist in developing rates.

With respect to stability, THESL also recognizes that the results of the cost allocation study, in combination with existing rate structures, expiring rate riders, and base revenue requirement over the three test years can lead to significant fluctuation in rates to customers. THESL has designed rates that collect the annual revenue requirement, incrementally implement the changes suggested by the cost allocation study, and provide for a stable progression of customer rates.

IMPLEMENTATION OF COST ALLOCATION RESULTS

Revenue/Cost Ratios

The results of the cost allocation exercise are provided in Exhibit L1. As noted, applying the cost allocation model to 2006 costs and rates showed that some rate classes are over-recovering and some rate classes are under-recovering. For the 2008-2010 test years, rates were developed to close the gaps in cost recovery, thereby moving each rate class closer to recovering its full cost of service.

A move to full cost recovery for each rate class is not warranted in the current application due to a number of factors.

First, full cost recovery would lead to significant changes in rates for most rate classes over a short period of time – even if spread over the full three-year rate application. As noted, stability in rates for customers is an important rate design principle.

Second, while the OEB's Cost Allocation exercise has been very worthwhile and the effort put into it is reflected in the quality of the resulting model, like any model which relies on estimated data values and a significant judgement for a number of inputs, the numerical results should not be taken as definitive. There is scope for variation in the values produced by the model that could result in significant changes in cost-revenue ratios (for example, the use of the generic 35:65 customer/demand related split for joint use assets significantly impacts a large portion of distribution costs).

Finally, in any given year the allocation of costs provided by the model can produce revenue/cost ratios that are different from unity. Targeting exact unity in any particular year will lead to unnecessary rate changes.

For these reasons, the rates developed reflect movement towards unity in the different rate classes, without targeting a revenue/cost ratio of exactly one. THESL targeted a revenue/cost ratio of 90 percent for the residential sector by 2010 and shifted the allocation across all rates classes on the same percentage basis as the residential sector (eg: a 10 percent change in the under recovery of the residential class was matched by a 10 percent change in the associated over or under recovery in other rate classes).

Table 2 summarizes the revenue/cost ratios based on the proposed rates and revenue requirement.

Table 2: Revenue / Cost Ratios

	2006 Historical	2008 Test	2009 Test	2010 Test
Residential	84.8%	85.8%	86.8%	89.5%
General Service <50kW	94.7%	97.8%	100.5%	98.1%
General Service 50-1000kW[1]	140.5%	129.2%	125.8%	123.1%
Intermediate 1000-5000kW	148.0%	135.9%	132.3%	127.0%
Large Use	114.8%	110.1%	108.5%	105.8%
Streetlighting	10.7%	27.1%	32.3%	39.7%
Unmetered Scattered Load	44.3%	48.5%	71.1%	79.5%

Notes:

1. 2006 GS 50-1000kW is for interval metered subclass

Based on the proposed rates, the revenue/cost ratio for the residential class increases from just under 85 percent in 2006 to just under 90 percent in 2010. Since the residential class is allocated the greatest portion of distribution costs, the five percent increase represents a significant increase in the revenue requirement collected from this class. The 15-20 percent reduction in the revenue/cost ratios for the GS 50-1000kW and Intermediate classes from the 140-150 percent range in 2006 down to the 125 percent range in 2010 represents a smaller dollar amount. The streetlighting and unmetered scattered load classes see a significant increase in their revenue/cost ratios, however, since the costs allocated to these classes is smaller, they see a smaller dollar impact with respect to revenue requirement.

Fixed versus Variable Charge

The OEB's Cost Allocation Model included a calculation of a theoretical monthly fixed component of costs under different assumptions. The stated basis of this calculation was to provide the OEB with information to assist with future discussions on rate design issues.

THESL has included in its rate design consideration of the fixed component generated by the Cost Allocation model. In designing rates for the test year, the fixed component of rates has been adjusted toward the levels suggested using the Cost Allocation model definition for Directly Related Customer Costs adjusted for Peak Load Carrying Capacity (this definition, described on pages 104-105 of the EB-2005-0317 Board Directions, includes costs directly attributable to a customer, such as meter and billing costs, plus an allocation of administrative and general costs). In THESL's opinion, this level of fixed charge is most representative of the actual fixed costs to serve a customer relative to the other two methodological options presented in the model (which were Avoided Cost methodology and Direct Related Customer Cost without PLCC adjustment).

THESL has not targeted a level that exactly matches the model results, but has moved directionally towards these levels by increasing or decreasing the fixed charge by six percent in each year. THESL submits that this rate of change strikes a reasonable balance between impacts on customers and the need to properly reflect fixed costs in the fixed component of rates.

Transformer Allowance

The OEB's Cost Allocation Model also included calculations designed to provide estimates of transformation costs for comparison with current transformation allowances for customers who own their own transformation.

As the transformation allowance was set previously on a generic basis for LDCs throughout the province (with a few exceptions), THESL is not proposing to change its current transformer allowance credit in this application. If the results of the forthcoming OEB Rate Design review include required changes in transformer allowance credits, THESL will implement them at that time.

Billing Determinants

THESL is not proposing any changes to the currently approved billing determinants for any customer class. Customers will continue to be billed on 30-day fixed portion and on a kVA or kWh variable portion. For the Unmetered Scattered Load class, customers will continue to be charged a monthly service charge, a per-connections charge and a variable charge based on kWh.

Proposed Consolidation of GS 50-1000kW Rate Classes

THESL proposes that the current two rate classes for General Service customers with demands between 50-1000kW – currently distinguished by being metered with an interval demand meter or with a standard energy meter – be combined for the 2008 rate year.

As the rollout of smart meters continues, all customers – including GS 50-1000kW – will be required to have an interval meter installed. The distinction between the GS 50-1000kW non-interval meter rate class and the GS 50-1000kW interval meter rate class with therefore cease to exist.

Currently, distribution rates for these two classes of customer are very similar, as shown in Table 3 below.

Table 3: 2007 Approved Distribution Rates

	GS 50-1000kW Non-Interval Meter	GS 50-1000kW Interval Meter
Service Charge ($/30 Days)	$26.26	$26.50
Variable Charge ($/max kVA/30 days)	$4.98	$4.98

Note: Service charge includes $0.68 smart meter rate rider for both classes

The difference in the monthly service charge is primarily attributed to the differences in meter costs between these two classes.

The current transmission charges (network and connection charges) are different for each of these rate classes also. THESL proposes that these rates also be combined for 2008.

THESL submits that it is appropriate to combine these two classes into a single class for the 2008 rate year and that the impact on customers in these two classes is negligible.

Standby Rates

In RP-2005-0020 THESL received approval from the OEB, on an interim basis, for Standby rates to be applied to generation customers. The approved rates consist of a monthly administration charge, a fixed monthly charge and a variable standby facility rate that matches both the fixed and variable rates for the applicable rate class for each customer (i.e., a customer with a nameplate generation rating of 2000kW would be assessed a fixed and variable rate the same as any other customer in that same class). For those months a generator takes standby power from the utility in excess of the contract amount, the variable standby facility rate is applied to the contracted standby demand.

The OEB indicated in its decision on generic issues (EB-2005-0529), that a proceeding on standby rates for all Ontario LDCs would be established some time in the future. The OEB has indicated in its recent announcement of the Review of Electricity Rate Design (EB-2007-0031) that it wishes to address the issue of rates for load displacement and distributed generation.

Until such time the OEB's process on rate design is complete, THESL believes it would be premature to make changes in its design of rates for these customers and proposes that

Standby facility rates continue to match the rates in the respective rate classes. The monthly administrative charge will remain unchanged.

Rate Riders

Rate riders for proposed variance accounts are described in detail in Exhibit J1, Tab 2, Schedule 10.

Rate Adjustment

Exhibit M1, Tab 3, Schedules 1 to 3 show the existing and proposed rates, revenue at existing rates and revenue at proposed rates by customer class.

Revenue Reconciliation

Exhibit M1, Tab 4, Schedules 1 to 3 show the difference between revenue at the proposed rates and allocated revenue requirements by customer class.

Bill Impacts

A summary of monthly customers' bills for representative customers on a distribution and total bill basis is shown in Exhibit M1, Tab 1, Schedule 2.

Details of the impacts of the proposed rates are detailed in Exhibit O1. 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 various levels of consumption within each rate class.

Summary Bill Comparisons

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		Monthly Bill ($)				Annual Change			
1	**Rate Class**	**2007**	**2008**	**2009**	**2010**	**2008**	**2009**	**2010**	**Average 2007-2010**
2									
3	Residential (1000 kWh)								
4	Distribution	27.50	32.15	34.25	35.84	16.9%	6.5%	4.6%	9.2%
5	Rate Rider	3.88	(1.00)	0.00	0.00	-125.8%	-100.0%	0.0%	-100.0%
6	Distribution and Rate Rider	31.38	31.15	34.25	35.84	-0.7%	10.0%	4.6%	4.5%
7	Total Bill	112.78	112.55	115.65	117.24	-0.2%	2.8%	1.4%	1.3%
8									
9	General Service <50 kW (10,000 kWh)								
10	Distribution	201.07	229.37	239.44	249.84	14.1%	4.4%	4.3%	7.5%
11	Rate Rider	15.68	(10.00)	0.00	0.00	-163.8%	-100.0%	0.0%	-100.0%
12	Distribution and Rate Rider	216.75	219.37	239.44	249.84	1.2%	9.1%	4.3%	4.8%
13	Total Bill	1,094.77	1,097.39	1,117.46	1,127.86	0.2%	1.8%	0.9%	1.0%
14									
15	GS 50-1000 kW Interval Metered (500 kW, 556 kVA and 200,000 kWh)								
16	Distribution	2,792.49	3,029.78	3,132.69	3,161.79	8.5%	3.4%	0.9%	4.2%
17	Rate Rider	50.68	(177.78)	0.00	0.00	-450.8%	-100.0%	0.0%	-100.0%
18	Distribution and Rate Rider	2,843.17	2,852.00	3,132.69	3,161.79	0.3%	9.8%	0.9%	3.6%
19	Total Bill	20,379.53	20,388.37	20,669.05	20,698.15	0.0%	1.4%	0.1%	0.5%
20									
21	1000-5000 kW (2,000 kW, 2,222 kVA, and 1,000,000 kWh)								
22	Distribution	9,961.86	10,770.24	11,127.55	11,246.67	8.1%	3.3%	1.1%	4.1%
23	Rate Rider	156.24	(800.00)	0.00	0.00	-612.0%	-100.0%	0.0%	-100.0%
24	Distribution and Rate Rider	10,118.10	9,970.24	11,127.55	11,246.67	-1.5%	11.6%	1.1%	3.6%
25	Total Bill	96,215.92	96,068.06	97,225.37	97,344.49	-0.2%	1.2%	0.1%	0.4%
26									
27	Large Use (5,000 kW, 5,556 kVA and 2,500,000 kWh)								
28	Distribution	22,480.52	24,939.37	25,972.34	26,499.54	10.9%	4.1%	2.0%	5.6%
29	Rate Rider	389.57	(2,611.11)	0.00	0.00	-770.3%	-100.0%	0.0%	-100.0%
30	Distribution and Rate Rider	22,870.09	22,328.25	25,972.34	26,499.54	-2.4%	16.3%	2.0%	5.0%
31	Total Bill	235,551.94	235,010.10	238,654.19	239,181.39	-0.2%	1.6%	0.2%	0.5%
32									
33	Streetlighting (1 kW and 365 kWh)								
34	Distribution	3.86	9.41	11.71	14.22	143.8%	24.4%	21.4%	54.4%
35	Rate Rider	0.08	(0.30)	0.00	0.00	-475.0%	-100.0%	0.0%	-100.0%
36	Distribution and Rate Rider	3.94	9.11	11.71	14.22	131.2%	28.5%	21.4%	53.4%
37	Total Bill	33.95	39.12	41.72	44.23	15.2%	6.6%	6.0%	9.2%
38									
39	Scattered Load (1 kW and 365 kWh)								
40	Distribution	8.85	12.74	14.68	16.37	44.0%	15.2%	11.5%	22.8%
41	Rate Rider	0.51	(0.33)	0.00	0.00	-164.3%	-100.0%	0.0%	-100.0%
42	Distribution and Rate Rider	9.36	12.42	14.68	16.37	32.6%	18.3%	11.5%	20.5%
43	Total Bill	38.49	41.54	43.81	45.50	7.9%	5.5%	3.9%	5.7%

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000 kW Non-Interval Meter

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 and with a non-interval meter. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

50 - 1000 kW Interval Meter

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 and with an interval meter. This rate also applies to bulk metered residential apartment buildings or the house service of a residential apartment building with more than 6 units.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge (includes Smart Meter rate rider of $0.68)	$	12.68	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0155	
Regulatory Asset Recovery	$/kWh	0.0032	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge (includes Smart Meter rate rider of $0.68)	$	16.75	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0185	
Regulatory Asset Recovery	$/kWh	0.0015	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service 50 to 5000 kW

Non Interval Meters - 50 to 1000 kW

Service Charge (includes Smart Meter rate rider of $0.68)	$	26.26	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	4.98	per 30 days
Regulatory Asset Recovery	$/kVA	0.31	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.23	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.68	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Interval Meters - 50 to 1000 kW

Service Charge (includes Smart Meter rate rider of $0.68)	$	26.50	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	4.98	per 30 days
Regulatory Asset Recovery	$/kVA	0.09	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

1000 to 5000 kW

Service Charge (includes Smart Meter rate rider of $0.68)	$	718.10	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	4.16	per 30 days
Regulatory Asset Recovery	$/kVA	0.07	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	

133	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
134				
135	**Large Use**			
136	Service Charge (includes Smart Meter rate rider of $0.68)	$	2,758.98	per 30 days
137	Distribution Volumetric Rate (with LV Charges)	$/kVA	3.55	per 30 days
138	Regulatory Asset Recovery	$/kVA	0.07	per 30 days
139	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
140	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
141	Wholesale Market Service Rate	$/kWh	0.0052	
142	Rural Rate Protection Charge	$/kWh	0.0010	
143	Debt Retirement Charge	$/kWh	0.0070	
144	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
145				
146				
147				
148	**Standby Power - APPROVED ON AN INTERIM BASIS**			
149				
150	Standby Administration Charge	$	197.91	per 30 days
151				
152	***Standby Charge – for a month where standby power is not provided. The distribution volumetric rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
153	General Service 50 – 1000 kW	$/kVA	4.98	per 30 days
154	General Service 1000 – 5000 kW	$/kVA	4.16	per 30 days
155	Large Use	$/kVA	3.55	per 30 days
156				
157	**Unmetered Scattered Load**			
158	Service Charge	$	1.99	per 30 days
159	Connection Charge	$	0.29	per 30 days
160	Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0180	
161	Regulatory Asset Recovery	$/kWh	0.0014	
162	Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
163	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
164	Wholesale Market Service Rate	$/kWh	0.0052	
165	Rural Rate Protection Charge	$/kWh	0.0010	
166	Debt Retirement Charge	$/kWh	0.0070	
167	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
168				
169	**Street Lighting**			
170	Service Charge (per connection)	$	0.26	per 30 days
171	Distribution Volumetric Rate (with LV Charges)	$/kVA	3.60	per 30 days
172	Regulatory Asset Recovery	$/kVA	0.08	per 30 days
173	Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
174	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
175	Wholesale Market Service Rate	$/kWh	0.0052	
176	Rural Rate Protection Charge	$/kWh	0.0010	

177	Debt Retirement Charge	$/kWh	0.0070	
178	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
179				
180				
181	**Specific Service Charges**			
182				
183	***Customer Administration***			
184				
185	Duplicate Invoices for Previous Billing	$	15.00	
186	Easement Letter	$	15.00	
187	Income Tax Letter	$	15.00	
188	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	
189	Returned Cheque (plus bank charges)	$	15.00	
190	Special Meter Reads	$	30.00	
191	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	
192				
193	***Non-Payment of Account***			
194				
195	Late Payment - per month	%	1.50	
196	Late Payment - per annum	%	19.56	
197	Collection of Account Charge – No Disconnection	$	30.00	
198	Disconnect/Reconnect Charges for non-payment of account - At Meter During Regular Hours	$	65.00	
199	Disconnect/Reconnect Charges for non-payment of account - At Meter After Hours	$	185.00	
200				
201	Install/Remove Load Control Device – During Regular hours	$	65.00	
202	Install/Remove Load Control Device – After Regular hours	$	185.00	
203				
204	Disconnect/Reconnect at Pole – During Regular Hours	$	185.00	
205	Disconnect/Reconnect at Pole – After Regular Hours	$	415.00	
206				
207	Specific Charge for Access to the Power Poles – per pole/year	$	22.35	
208	Specific Charge for Access to the Power Poles – per pole/year (Third Party Attachments to Poles)	$	18.55	
209	Specific Charge for Access to the Power Poles – per pole/year (Hydro Attachments on Third Party Poles)	$	(22.75)	
210				
211	***Allowances***			
212				
213	Transformer Allowance for Ownership	$/kVA	(0.62)	per 30 days
214	Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	
215				
216	**LOSS FACTORS**			
217	Billing Determinant:			
218	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 Other Regulated 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 5,000 kW or greater	1.0141
Total Loss Factors	
Secondary Metered Customers	
(E) Customer less than 5,000 kW(B)*(C)	1.0376
(F) Customer 5,000 kW or greater(B)*(D)	1.0187
Primary metered customers	
(G) Customer less than 5,000 kW (A)*(E)	1.0272
(F) Customer 5,000 kW or greater (A)*(F)	1.0085

RETAIL SERVICE CHARGES

These are charges for service 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

Charge to a retailer:

1) standard charge (one-time charge) of $100 per agreement, per retailer.
2) monthly fixed charge of $20 per month, per retailer.
3) monthly variable charge of $0.50 per month, per customer

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per month, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per month, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2008

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2008 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2008 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000kW

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.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge	$	14.85	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0173	
Regulatory Asset Recovery	$/kWh	-0.0010	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge	$	19.37	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0210	
Regulatory Asset Recovery	$/kWh	-0.0010	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	

90	Rural Rate Protection Charge	$/kWh	0.0010	
91	Debt Retirement Charge	$/kWh	0.0070	
92	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
93				
94	**General Service 50 to 5000 kW**			
95				
96	***50 to 1000 kW***			
97	Service Charge	$	29.78	per 30 days
98	Distribution Volumetric Rate (with LV Charges)	$/kVA	5.40	per 30 days
99	Regulatory Asset Recovery	$/kVA	-0.32	per 30 days
100	Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
101	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
102	Wholesale Market Service Rate	$/kWh	0.0052	
103	Rural Rate Protection Charge	$/kWh	0.0010	
104	Debt Retirement Charge	$/kWh	0.0070	
105	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
106				
107	***1000 to 5000 kW***			
108	Service Charge	$	725.80	per 30 days
109	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.52	per 30 days
110	Regulatory Asset Recovery	$/kVA	-0.36	per 30 days
111	Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
112	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
113	Wholesale Market Service Rate	$/kWh	0.0052	
114	Rural Rate Protection Charge	$/kWh	0.0010	
115	Debt Retirement Charge	$/kWh	0.0070	
116	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
117				
118	**Large Use**			
119	Service Charge	$	2,883.81	per 30 days
120	Distribution Volumetric Rate (with LV Charges)	$/kVA	3.97	per 30 days
121	Regulatory Asset Recovery	$/kVA	-0.47	per 30 days
122	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
123	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
124	Wholesale Market Service Rate	$/kWh	0.0052	
125	Rural Rate Protection Charge	$/kWh	0.0010	
126	Debt Retirement Charge	$/kWh	0.0070	
127	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
128				
129	**Standby Power - APPROVED ON AN INTERIM BASIS**			
130				
131	Standby Administration Charge	$	197.91	per 30 days
132				
133	***Standby Charge – for a month where standby power is not provided. The volumetric distribution rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
134	General Service 50 – 1000 kW	$/kVA	5.40	per 30 days
135	General Service 1000 – 5000 kW	$/kVA	4.52	per 30 days
136	Large Use	$/kVA	3.97	per 30 days
137				

Unmetered Scattered Load

Service Charge	$	2.96	per 30 days
Connection Charge (per connection)	$	0.33	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0259	
Regulatory Asset Recovery	$/kWh	-0.0009	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Street Lighting

Service Charge (per connection)	$	0.66	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	8.75	per 30 days
Regulatory Asset Recovery	$/kVA	-0.30	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Specific Service Charges

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
Disconnect/Reconnect Charges for non-payment of account - 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

185	Disconnect/Reconnect at Pole – After Regular Hours	$	415.00	
186				
187	Specific Charge for Access to the Power Poles – per pole/year	$	22.35	
188				
189	***Allowances***			
190				
191	Transformer Allowance for Ownership	$/kVA	(0.62)	per 30 days
192	Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)	
193				
194	**LOSS FACTORS**			
195	Billing Determinant:			
196	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 Other Regulated Rates.			
197				
198	(A) Primary Metering Adjustment		0.9900	
199				
200	(B) Supply Facilities Loss Factor		1.0045	
201				
202	***Distribution Loss Factors***			
203	(C) Customer less than 5,000 kW		1.0330	
204	(D) Customer 5,000 kW or greater		1.0141	
205				
206	**Total Loss Factors**			
207				
208	***Secondary Metered Customers***			
209	(E) Customer less than 5,000 kW(B)*(C)		1.0376	
210	(F) Customer 5,000 kW or greater(B)*(D)		1.0187	
211				
212	***Primary metered customers***			
213	(G) Customer less than 5,000 kW (A)*(E)		1.0272	
214	(F) Customer 5,000 kW or greater (A)*(F)		1.0085	
215				
216	RETAIL SERVICE CHARGES			
217				
218	These are charges for service provided by THESL to retailers or customers related to the supply of competitive electricity and are defined in the 2006 Electricity Distribution Rate Handbook.			
219				
220	Establishing Service Agreements			
221				
222	Charge to a retailer:			
223				
224	1) standard charge (one-time charge) of $100 per agreement, per retailer.			
225	2) monthly fixed charge of $20 per 30 days, per retailer.			
226	3) monthly variable charge of $0.50 per 30 days, per customer			
227				

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per 30 days, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per 30 days, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulatec Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2009 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2009 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000kW

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.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge	$	16.85	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0174	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge	$	21.44	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0218	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	

90	Rural Rate Protection Charge	$/kWh	0.0010	
91	Debt Retirement Charge	$/kWh	0.0070	
92	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
93				
94	**General Service 50 to 5000 kW**			
95				
96	***50 to 1000 kW***			
97	Service Charge	$	32.69	per 30 days
98	Distribution Volumetric Rate (with LV Charges)	$/kVA	5.58	per 30 days
99	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
100	Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
101	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
102	Wholesale Market Service Rate	$/kWh	0.0052	
103	Rural Rate Protection Charge	$/kWh	0.0010	
104	Debt Retirement Charge	$/kWh	0.0070	
105	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
106				
107	***1000 to 5000 kW***			
108	Service Charge	$	705.33	per 30 days
109	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.69	per 30 days
110	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
111	Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
112	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
113	Wholesale Market Service Rate	$/kWh	0.0052	
114	Rural Rate Protection Charge	$/kWh	0.0010	
115	Debt Retirement Charge	$/kWh	0.0070	
116	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
117				
118	**Large Use**			
119	Service Charge	$	2,639.01	per 30 days
120	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.20	per 30 days
121	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
122	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
123	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
124	Wholesale Market Service Rate	$/kWh	0.0052	
125	Rural Rate Protection Charge	$/kWh	0.0010	
126	Debt Retirement Charge	$/kWh	0.0070	
127	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
128				
129	**Standby Power - APPROVED ON AN INTERIM BASIS**			
130				
131	Standby Administration Charge	$	197.91	per 30 days
132				
133	***Standby Charge – for a month where standby power is not provided. The volumetric distribution rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
134	General Service 50 – 1000 kW	$/kVA	5.58	per 30 days
135	General Service 1000 – 5000 kW	$/kVA	4.69	per 30 days
136	Large Use	$/kVA	4.20	per 30 days
137				

Unmetered Scattered Load

Service Charge	$	3.42	per 30 days
Connection Charge (per connection)	$	0.35	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0299	
Regulatory Asset Recovery	$/kWh	0.00	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Street Lighting

Service Charge (per connection)	$	0.89	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kVA	10.82	per 30 days
Regulatory Asset Recovery	$/kVA	0.00	per 30 days
Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

Specific Service Charges

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
Disconnect/Reconnect Charges for non-payment of account - 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	
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)	

LOSS FACTORS

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 Other Regulated 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 5,000 kW or greater	1.0141
Total Loss Factors	
Secondary Metered Customers	
(E) Customer less than 5,000 kW(B)*(C)	1.0376
(F) Customer 5,000 kW or greater (B)*(D)	1.0187
Primary metered customers	
(G) Customer less than 5,000 kW (A)*(E)	1.0272
(F) Customer 5,000 kW or greater (A)*(F)	1.0085

RETAIL SERVICE CHARGES

These are charges for service 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

Charge to a retailer:

1) standard charge (one-time charge) of $100 per agreement, per retailer.
2) monthly fixed charge of $20 per 30 days, per retailer.
3) monthly variable charge of $0.50 per 30 days, per customer

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per 30 days, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per 30 days, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
TARIFFS OF RATES AND CHARGES
Effective May 1, 2010

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

Application

►The application of these rates and charges shall be in accordance with the Licence of THESL and any Codes, Guidelines or Orders 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 THESL's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

►This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

Effective Dates

DISTRIBUTION RATES - May 1, 2010 for all consumption or deemed consumption services used on or after that date.

SPECIFIC SERVICE CHARGES - May 1, 2010 for all charges incurred by customers on or after that date.

LOSS FACTOR ADJUSTMENT – There are no changes to the current loss factors.

Service Classifications

Residential

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.

General Service Less Than 50 kW

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.

General Service 50 to 5000 kW

50 - 1000kW

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.

Intermediate Use - 1000 to 5000 kW

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

Large Use

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.

Unmetered Scattered Load

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.

Standby Power

This classification refers to an account that has Load Displacement Generation and requires THESL to provide back-up service.

Street Lighting

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.

RATES AND CHARGES

Residential

Service Charge	$	18.14	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0177	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0057	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
Wholesale Market Service Rate	$/kWh	0.0052	
Rural Rate Protection Charge	$/kWh	0.0010	
Debt Retirement Charge	$/kWh	0.0070	
Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days

General Service Less Than 50 kW

Service Charge	$	22.84	per 30 days
Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0227	
Regulatory Asset Recovery	$/kWh	0.0000	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	

89	Wholesale Market Service Rate	$/kWh	0.0052	
90	Rural Rate Protection Charge	$/kWh	0.0010	
91	Debt Retirement Charge	$/kWh	0.0070	
92	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
93				
94	**General Service 50 to 5000 kW**			
95				
96	***50 to 1000 kW***			
97	Service Charge	$	34.01	per 30 days
98	Distribution Volumetric Rate (with LV Charges)	$/kVA	5.63	per 30 days
99	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
100	Retail Transmission Rate – Network Service Rate	$/kW	2.27	per 30 days
101	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.71	per 30 days
102	Wholesale Market Service Rate	$/kWh	0.0052	
103	Rural Rate Protection Charge	$/kWh	0.0010	
104	Debt Retirement Charge	$/kWh	0.0070	
105	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
106				
107	***1000 to 5000 kW***			
108	Service Charge	$	691.11	per 30 days
109	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.75	per 30 days
110	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
111	Retail Transmission Rate – Network Service Rate	$/kW	2.40	per 30 days
112	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.77	per 30 days
113	Wholesale Market Service Rate	$/kWh	0.0052	
114	Rural Rate Protection Charge	$/kWh	0.0010	
115	Debt Retirement Charge	$/kWh	0.0070	
116	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
117				
118	**Large Use**			
119	Service Charge	$	2,277.32	per 30 days
120	Distribution Volumetric Rate (with LV Charges)	$/kVA	4.36	per 30 days
121	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
122	Retail Transmission Rate – Network Service Rate	$/kW	2.50	per 30 days
123	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.80	per 30 days
124	Wholesale Market Service Rate	$/kWh	0.0052	
125	Rural Rate Protection Charge	$/kWh	0.0010	
126	Debt Retirement Charge	$/kWh	0.0070	
127	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
128				
129	**Standby Power - APPROVED ON AN INTERIM BASIS**			
130				
131	Standby Administration Charge	$	197.91	per 30 days
132				
133	***Standby Charge – for a month where standby power is not provided. The volumetric distribution rate is applied to the contracted amount (e.g. nameplate rating of generation facility).***			
134	General Service 50 – 1000 kW	$/kVA	5.63	per 30 days

135	General Service 1,000 – 5000 kW	$/kVA	4.75	per 30 days
136	Large Use	$/kVA	4.36	per 30 days
137				
138	**Unmetered Scattered Load**			
139	Service Charge	$	3.74	per 30 days
140	Connection Charge (per connection)	$	0.37	per 30 days
141	Distribution Volumetric Rate (with LV Charges)	$/kWh	0.0336	
142	Regulatory Asset Recovery	$/kWh	0.00	
143	Retail Transmission Rate – Network Service Rate	$/kWh	0.0058	
144	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045	
145	Wholesale Market Service Rate	$/kWh	0.0052	
146	Rural Rate Protection Charge	$/kWh	0.0010	
147	Debt Retirement Charge	$/kWh	0.0070	
148	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
149				
150	**Street Lighting**			
151	Service Charge (per connection)	$	1.12	per 30 days
152	Distribution Volumetric Rate (with LV Charges)	$/kVA	13.10	per 30 days
153	Regulatory Asset Recovery	$/kVA	0.00	per 30 days
154	Retail Transmission Rate – Network Service Rate	$/kW	2.75	per 30 days
155	Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.03	per 30 days
156	Wholesale Market Service Rate	$/kWh	0.0052	
157	Rural Rate Protection Charge	$/kWh	0.0010	
158	Debt Retirement Charge	$/kWh	0.0070	
159	Regulated Price Plan – Administration Charge (if applicable)	$	0.25	per 30 days
160				
161	**Specific Service Charges**			
162				
163	***Customer Administration***			
164				
165	Duplicate Invoices for Previous Billing	$	15.00	
166	Easement Letter	$	15.00	
167	Income Tax Letter	$	15.00	
168	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00	
169	Returned Cheque (plus bank charges)	$	15.00	
170	Special Meter Reads	$	30.00	
171	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	
172				
173	***Non-Payment of Account***			
174				
175	Late Payment - per month	%	1.50	
176	Late Payment - per annum	%	19.56	
177	Collection of Account Charge – No Disconnection	$	30.00	
178	Disconnect/Reconnect Charges for non-payment of account - At Meter During Regular Hours	$	65.00	
179	Disconnect/Reconnect Charges for non-payment of account - 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	
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)	

LOSS FACTORS

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 Other Regulated 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 5,000 kW or greater (B)*(D)	1.0187
Primary metered customers	
(G) Customer less than 5,000 kW (A)*(E)	1.0272
(F) Customer 5,000 kW or greater (A)*(F)	1.0085

RETAIL SERVICE CHARGES

These are charges for service 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

Charge to a retailer:

1) standard charge (one-time charge) of $100 per agreement, per retailer.
2) monthly fixed charge of $20 per 30 days, per retailer.

3) monthly variable charge of $0.50 per 30 days, per customer

Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per 30 days, per customer, will be collected from the retailer.

Retailer-Consolidated Billing

An avoided cost credit of $0.30 per 30 days, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

Service Transaction Requests (STR)

1) request fee of $0.25 per request, regardless of whether or not the STR can be processed.
2) processing fee of $0.50 per request, applied to the requesting party if the request is processed.

2008 RATE ADJUSTMENT SUMMARY

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
									1.013888889	**1.013888889**	**<<DOS factor, 365/360**	
1			**2008 Forecast Customers at end of June**	**2008 Forecast kWh Units**	**2008 Forecast kVA Units**	**2007 Approved Rates ($)**	**2008 Proposed Rates ($)**	**% Change**	**2008 Annual Revenue at 2007 Approved Rates ($)**	**2008 Annual Revenue at 2008 Proposed Rates ($)**	**$ Change**	**% Change**
2	**RESIDENTIAL**											
3	Customer Charge		617,157			12.00	14.85	23.8%	90,104,933	111,504,854	21,399,922	23.8%
4	Distribution Charge			5,498,828,031		0.0155	0.0173	11.6%	85,231,834	95,129,725	9,897,890	11.6%
5	Customer+Distribution								175,336,767	206,634,579	31,297,812	17.9%
6												
7	**GENERAL SERVICE (< 50 kW)**											
8	Customer Charge		66,934			16.07	19.37	20.5%	13,086,824	15,774,224	2,687,400	20.5%
9	Distribution Charge			2,575,446,564		0.0185	0.0210	13.5%	47,645,761	54,084,378	6,438,616	13.5%
10	Customer+Distribution								60,732,586	69,858,602	9,126,017	15.0%
11												
12	**GENERAL SERVICE - Non Interval Meters (50 - 1000 kW)**											
13	Customer Charge		2,135			25.58	29.78	16.4%	664,601	773,722	109,121	16.4%
14	Distribution Charge				3,796,584	4.98	5.40	8.4%	19,169,584	20,786,296	1,616,712	8.4%
15	Customer+Distribution								19,834,184	21,560,018	1,725,833	8.7%
16												
17	**GENERAL SERVICE - Interval Meters (50 - 1000 kW)**											
18	Customer Charge		9,451			25.82	29.78	15.3%	2,969,115	3,424,486	455,372	15.3%
19	Distribution Charge				22,141,961	4.98	5.40	8.4%	111,798,453	121,227,239	9,428,785	8.4%
20	Customer+Distribution								114,767,568	124,651,725	9,884,157	8.6%
21												
22	**GENERAL SERVICE (1,000 - 5000 kW)**											
23	Customer Charge		528			717.42	725.80	1.2%	4,610,632	4,664,488	53,856	1.2%
24	Distribution Charge				11,740,732	4.16	4.52	8.7%	49,519,799	53,805,166	4,285,367	8.7%
25	Customer+Distribution								54,130,431	58,469,654	4,339,223	8.0%
26												
27	**LARGE USERS**											
28	Customer Charge		49			2,758.30	2,883.81	4.6%	1,644,407	1,719,231	74,825	4.6%
29	Distribution Charge				5,428,878	3.55	3.97	11.8%	19,540,192	21,851,989	2,311,797	11.8%
30	Customer+Distribution								21,184,598	23,571,220	2,386,622	11.3%
31												
32	**STREET LIGHTING**											
33	Customer Charge		159,861			0.26	0.66	153.8%	505,694	1,283,684	777,990	153.8%
34	Distribution Charge				317,526	3.60	8.75	143.1%	1,158,971	2,816,944	1,657,973	143.1%
35	Customer+Distribution								1,664,665	4,100,628	2,435,963	146.3%
36												
37	**SMALL UNMETERED SCATTERED LOADS**											
38	Admin/Processing		1,466			1.99	2.96	48.7%	35,492	52,792	17,300	48.7%
39	Service Charge per Conne		17,721			0.29	0.33	13.8%	62,526	71,151	8,624	13.8%
40	Distribution Charge			57,950,907		0.0180	0.0259	43.9%	1,043,116	1,500,929	457,812	43.9%
41	Customer+Distribution								1,141,135	1,624,871	483,737	42.4%
42												
43	**TRANSFORMER ALLOWANCE**											
44					19,309,571	-0.62	-0.62	0.0%	-12,138,211	-12,138,211	0	0.0%
45												
46	**Customer + Distribution + Transformer Allowance**								**436,653,723**	**498,333,086**	**61,679,363**	**14.1%**

2009 RATE ADJUSTMENT SUMMARY

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
									1.013888889	1.013888889	<<DOS factor, 365/360	
1			2008 Forecast Customers at end of June	2009 Forecast kWh Units	2009 Forecast kVA Units	2008 Proposed Rates ($)	2009 Proposed Rates ($)	% Change	2009 Annual Revenue at 2008 Proposed Rates ($)	2009 Annual Revenue at 2009 Proposed Rates ($)	$ Change	% Change
2	**RESIDENTIAL**											
3	Customer Charge		644,567			14.85	16.85	13.5%	116,457,212.10	132,141,685.11	15,684,473.01	13.5%
4	Distribution Charge			5,613,078,765		0.0173	0.0174	0.6%	97,106,262.64	97,667,570.52	561,307.88	0.6%
5	Customer+Distribution								213,563,474.74	229,809,255.62	16,245,780.89	7.6%
6												
7	**GENERAL SERVICE (< 50 kW)**											
8	Customer Charge		66,878			19.37	21.44	10.7%	15,761,026.80	17,445,349.23	1,684,322.43	10.7%
9	Distribution Charge			2,573,543,699		0.0210	0.0218	3.8%	54,044,417.69	56,103,252.65	2,058,834.96	3.8%
10	Customer+Distribution								69,805,444.48	73,548,601.87	3,743,157.39	5.4%
11												
12	**GENERAL SERVICE (50 - 1000 kW)**											
13	Customer Charge		11,605			29.78	32.69	9.8%	4,204,747.56	4,615,621.15	410,873.59	9.8%
14	Distribution Charge				25,700,536	5.40	5.58	3.3%	140,710,435.38	145,400,783.22	4,690,347.85	3.3%
15	Customer+Distribution								144,915,182.93	150,016,404.37	5,101,221.43	3.5%
16												
17	**GENERAL SERVICE (1,000 - 5000 kW)**											
18	Customer Charge		536			725.80	705.33	-2.8%	4,729,990.69	4,596,589.05	-133,401.64	-2.8%
19	Distribution Charge				11,769,012	4.52	4.69	3.8%	53,934,767.53	55,963,287.55	2,028,520.02	3.8%
20	Customer+Distribution								58,664,758.22	60,559,876.60	1,895,118.38	3.2%
21												
22	**LARGE USERS**											
23	Customer Charge		49			2,883.81	2,639.01	-8.5%	1,719,231.40	1,573,289.80	-145,941.60	-8.5%
24	Distribution Charge				5,441,942	3.97	4.20	5.8%	21,904,572.08	23,173,602.70	1,269,030.62	5.8%
25	Customer+Distribution								23,623,803.47	24,746,892.50	1,123,089.02	4.8%
26												
27	**STREET LIGHTING**											
28	Customer Charge		159,861			0.66	0.89	34.8%	1,283,683.83	1,731,028.20	447,344.37	34.8%
29	Distribution Charge				317,526	8.75	10.82	23.7%	2,816,943.71	3,483,352.11	666,408.40	23.7%
30	Customer+Distribution								4,100,627.54	5,214,380.30	1,113,752.76	27.2%
31												
32	**SMALL UNMETERED SCATTERED LOADS**											
33	Admin/Processing		1,466			2.96	3.42	15.5%	52,792.23	60,996.42	8,204.20	15.5%
34	Service Charge per Conne		17,721			0.33	0.35	6.1%	71,150.68	75,462.84	4,312.16	6.1%
35	Distribution Charge			58,101,913		0.0259	0.0299	15.4%	1,504,839.54	1,737,247.19	232,407.65	15.4%
36	Customer+Distribution								1,628,782.45	1,873,706.46	244,924.01	15.0%
37												
38	**TRANSFORMER ALLOWANCE**											
39					19,270,593	-0.62	-0.62	0.0%	-12,113,708.85	-12,113,708.85	0.00	0.0%
40												
41	**Customer + Distribution + Transformer Allowance Allowance**								**$ 504,188,365**	**$ 533,655,409**	**$ 29,467,044**	**5.8%**

2010 RATE ADJUSTMENT SUMMARY

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
									1.013888889	1.013888889	<<DOS factor, 365/360	
1			2010 Forecast Customers at end of June	2010 Forecast kWh Units	2010 Forecast kVA Units	2009 Proposed Rates ($)	2010 Proposed Rates ($)	% Change	2010 Annual Revenue at 2009 Approved Rates ($)	2010 Annual Revenue at 2010 Proposed Rates ($)	$ Change	% Change
2	**RESIDENTIAL**											
3	Customer Charge		679,914			16.85	18.14	7.7%	139,388,007	150,059,255	10,671,248	7.7%
4	Distribution Charge			5,785,918,437		0.0174	0.0177	1.7%	100,674,981	102,410,756	1,735,776	1.7%
5	Cust+Distribution Only								240,062,987	252,470,011	12,407,024	5.2%
6												
7	**GENERAL SERVICE (< 50 kW)**											
8	Customer Charge		66,823			21.44	22.84	6.5%	17,431,002	18,569,221	1,138,218	6.5%
9	Distribution Charge			2,574,909,409		0.0218	0.0227	4.1%	56,133,025	58,450,444	2,317,418	4.1%
10	Cust+Distribution Only								73,564,027	77,019,664	3,455,637	4.7%
11												
12	**GENERAL SERVICE (50 - 1000 kW)**											
13	Customer Charge		11,583			32.69	34.01	4.0%	4,607,021	4,793,049	186,028	4.0%
14	Distribution Charge				25,358,216	5.58	5.63	0.9%	143,464,108	144,749,628	1,285,521	0.9%
15	Cust+Distribution Only								148,071,129	149,542,678	1,471,549	1.0%
16												
17	**GENERAL SERVICE (1,000 - 5000 kW)**											
18	Customer Charge		543			705.33	691.11	-2.0%	4,660,244	4,566,290	-93,954	-2.0%
19	Distribution Charge				11,792,136	4.69	4.75	1.3%	56,073,245	56,790,600	717,355	1.3%
20	Cust+Distribution Only								60,733,489	61,356,890	623,401	1.0%
21												
22	**LARGE USERS**											
23	Customer Charge		49			2,639.01	2,277.32	-13.7%	1,573,290	1,357,662	-215,628	-13.7%
24	Distribution Charge				5,452,850	4.20	4.36	3.8%	23,220,054	24,104,628	884,574	3.8%
25	Cust+Distribution Only								24,793,344	25,462,290	668,946	2.7%
26												
27	**STREET LIGHTING**											
28	Customer Charge		159,861			0.89	1.12	25.8%	1,731,028	2,178,373	447,344	25.8%
29	Distribution Charge				317,526	10.82	13.10	21.1%	3,483,352	4,217,367	734,015	21.1%
30	Cust+Distribution Only								5,214,380	6,395,740	1,181,359	22.7%
31												
32	**SMALL UNMETERED SCATTERED LOADS**											
33	Admin/Processing		1,466			3.42	3.74	9.4%	60,996	66,704	5,707	9.4%
34	Service Charge per Conne		17,721			0.35	0.37	5.7%	75,463	79,775	4,312	5.7%
35	Distribution Charge			58,219,008		0.03	0.0336	12.4%	1,740,748	1,956,159	215,410	12.4%
36	Cust+Distribution Only								1,877,208	2,102,637	225,430	12.0%
37												
38	**TRANSFORMER ALLOWANCE**											
39					19,196,795	-0.62	-0.62	0.0%	-12,067,319	-12,067,319	0	0.0%
40												
41	**Customer + Distribution + Transformer Allowance**								**$ 542,249,246**	**$ 562,282,591**	**$ 20,033,345**	**3.7%**

2008 REVENUE RECONCILIATION SUMMARY

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
									1.013888889	1.013888889	<<DOS factor, 365/360				
1			2008 Forecast Customers at end of June	2008 Forecast kWh Units	2008 Forecast kVA Units	2008 Proposed Rates (Full Precision) ($)	2008 Proposed Rates ($)	% Difference	2008 Annual Revenue at Proposed Rates (Full Precision) ($)	2008 Annual Revenue at Proposed Rates ($)	$ Difference	% Difference	2008 Base Revenue Requirement ($)	$ Difference from Revenue at Proposed Rates	% Difference
2	**RESIDENTIAL**														
3	Customer Charge		617,157	5,498,828,031		14.852173	14.85	0.0%	111,521,169	111,504,854	-16,315	0.0%			
4	Distribution Charge					0.017270	0.0173	0.2%	94,962,386	95,129,725	167,339	0.2%			
5	Customer+Distribution								206,483,555	206,634,579	151,024	0.1%	206,483,542	151,037	0.1%
6															
7	**GENERAL SERVICE (< 50 kW)**														
8	Customer Charge		66,934	2,575,446,564		19.368735	19.37	0.0%	15,773,116	15,774,146	1,030	0.0%			
9	Distribution Charge					0.020988	0.0210	0.1%	54,052,677	54,084,378	31,701	0.1%			
10	Customer+Distribution								69,825,793	69,858,524	32,731	0.0%	69,825,871	32,654	0.0%
11															
12	**GENERAL SERVICE (50 - 1000 kW)**														
13	Customer Charge		11,587			29.778204	29.78	0.0%	4,197,955	4,198,208	253	0.0%			
14	Distribution Charge				25,938,545	5.400315	5.40	0.0%	142,021,817	142,013,534	-8,282	0.0%			
15	Customer+Distribution								146,219,772	146,211,743	-8,029	0.0%	146,219,442	-7,699	0.0%
16															
17	**GENERAL SERVICE (1,000 - 5000 kW)**														
18	Customer Charge		528			725.799047	725.80	0.0%	4,664,482	4,664,488	6	0.0%			
19	Distribution Charge				11,740,732	4.517515	4.52	0.1%	53,775,582	53,805,166	29,584	0.1%			
20	Customer+Distribution								58,440,064	58,469,654	29,590	0.1%	58,438,115	31,539	0.1%
21															
22	**LARGE USERS**														
23	Customer Charge		49			2,883.811989	2,883.81	0.0%	1,719,233	1,719,231	-1	0.0%			
24	Distribution Charge				5,428,878	3.973016	3.97	-0.1%	21,868,591	21,851,989	-16,602	-0.1%			
25	Customer+Distribution								23,587,823	23,571,220	-16,603	-0.1%	23,587,823	-16,603	-0.1%
26															
27	**STREET LIGHTING**														
28	Customer Charge		159,861			0.657438	0.66	0.4%	1,278,701	1,283,684	4,983	0.4%			
29	Distribution Charge				317,526	8.751690	8.75	0.0%	2,817,488	2,816,944	-544	0.0%			
30	Customer+Distribution								4,096,188	4,100,628	4,439	0.1%	4,096,188	4,439	0.1%
31															
32	**SMALL UNMETERED SCATTERED LOADS**														
33	Admin/Processing		1,466	57,950,907		2.964740	2.96	-0.2%	52,877	52,792	-85	-0.2%			
34	Service Charge per Connection		17,721			0.328370	0.33	0.5%	70,799	71,151	351	0.5%			
35	Distribution Charge					0.025908	0.0259		1,501,375	1,500,929	-447	0.0%			
36	Customer+Distribution								1,625,051	1,624,871	-180	0.0%	1,625,054	-182	0.0%
37															
38	**TRANSFORMER ALLOWANCE**														
39	- Annual				19,309,571	-0.62	-0.62	0.0%	-12,138,211	-12,138,211	0	0.0%	-12,138,211	0	0.0%
40															
41	**Sum of Customer, Distribution Charges and Transformer Allowance (LV Charges not included in rates due to rounding)**								**498,140,036**	**498,333,008**	**192,972**	**0.0%**	**498,137,824**	**195,184**	**0.0%**
42	**Other revenue Offsets**									**26,335,129**					
43	**2008 Total Operating Revenue**									**524,668,137**					
44	**2008 Service Revenue Requirement**									**524,728,383**					
45	**Difference (Total Operating Revenue - Service Revenue Requirement)**									**-60,246**					
46															

2009 REVENUE RECONCILIATION SUMMARY

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
									1.013888889	1.013888889	<<DOS factor, 365/360				
1			2009 Forecast Customers at end of June	2009 Forecast kWh Units	2009 Forecast kVA Units	2009 Proposed Rates (Full Precision) ($)	2009 Proposed Rates ($)	% Difference	2009 Annual Revenue at Proposed Rates (Full Precision) ($)	2009 Annual Revenue at Proposed Rates ($)	$ Difference	% Difference	2009 Base Revenue Requirement ($)	$ Difference from Revenue at Proposed Rates	% Difference
2	**RESIDENTIAL**														
3	Customer Charge		644,567			16.847670	16.85	0.0%	132,123,410	132,141,685	18,275	0.0%			
4	Distribution Charge			5,613,078,765		0.017405	0.0174	0.0%	97,697,397	97,667,571	-29,826	0.0%			
5	Cust+Distribution Only								229,820,807	229,809,256	-11,551	0.0%	229,820,728	-11,473	0.0%
6															
7	**GENERAL SERVICE (< 50 kW)**														
8	Customer Charge		66,878			21.437994	21.44	0.0%	17,443,717	17,445,349	1,632	0.0%			
9	Distribution Charge			2,573,543,699		0.021836	0.0218	-0.2%	56,195,181	56,103,253	-91,929	-0.2%			
10	Cust+Distribution Only								73,638,899	73,548,602	-90,297	-0.1%	73,638,899	-90,297	-0.1%
11															
12	**GENERAL SERVICE (50 - 1000 kW)**														
13	Customer Charge		11,605			32.691342	32.69	0.0%	4,615,811	4,615,621	-189	0.0%			
14	Distribution Charge				25,700,536	5.577509	5.58	0.0%	145,335,879	145,400,783	64,904	0.0%			
15	Cust+Distribution Only								149,951,690	150,016,404	64,714	0.0%	149,951,706	64,698	0.0%
16															
17	**GENERAL SERVICE (1,000 - 5000 kW)**														
18	Customer Charge		536			705.328453	705.33	0.0%	4,596,579	4,596,589	10	0.0%			
19	Distribution Charge				11,769,012	4.694926	4.69	-0.1%	56,022,066	55,963,288	-58,778	-0.1%			
20	Cust+Distribution Only								60,618,645	60,559,877	-58,768	-0.1%	60,621,748	-61,871	-0.1%
21															
22	**LARGE USERS**														
23	Customer Charge		49			2,639.009694	2,639.01	0.0%	1,573,290	1,573,290	0	0.0%			
24	Distribution Charge				5,441,942	4.202139	4.20	-0.1%	23,185,406	23,173,603	-11,803	-0.1%			
25	Cust+Distribution Only								24,758,695	24,746,892	-11,803	0.0%	24,758,695	-11,803	0.0%
26															
27	**STREET LIGHTING**														
28	Customer Charge		159,861			0.885715	0.89	0.5%	1,722,695	1,731,028	8,333	0.5%			
29	Distribution Charge				317,526	10.820203	10.82	0.0%	3,483,417	3,483,352	-65	0.0%			
30	Cust+Distribution Only								5,206,112	5,214,380	8,268	0.2%	5,206,112	8,268	0.2%
31															
32	**SMALL UNMETERED SCATTERED LOADS**														
33	Admin/Processing		1,466			3.424148	3.42	-0.1%	61,070	60,996	-74	-0.1%			
34	Service Charge per Connection		17,721			0.353566	0.35	-1.0%	76,232	75,463	-769	-1.0%			
35	Distribution Charge			58,101,913		0.029911	0.0299		1,737,873	1,737,247	-626	0.0%			
36	Cust+Distribution Only								1,875,175	1,873,706	-1,468	-0.1%	1,875,178	-1,471	-0.1%
37															
38	**TRANSFORMER ALLOWANCE**														
39					19,270,593	-0.62	-0.62	0.0%	-12,113,709	-12,113,709	0	0.0%	-12,113,709	0	0.0%
40															
41	**Sum of Customer, Distribution Charges and Transformer Allowance (LV Charges not included in rates due to rounding)**								**533,756,314**	**533,655,409**	**-100,905**	**0.0%**	**533,759,357**	**-103,948**	**0.0%**
42	**Other revenue Offsets**									**21,732,002**					
43	**2009 Total Operating Revenue**									**555,387,411**					
44	**2009 Service Revenue Requirement**									**555,746,789**					
45	**Difference (Total Operating Revenue-Service Revenue Requirement)**									**-359,378**					
46															

2010 REVENUE RECONCILIATION SUMMARY

Table 1

	Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9	Col.10	Col.11	Col.12	Col.13	Col.14	Col.15
									1.013888889	1.013888889	<<DOS factor, 365/360				
1			2010 Forecast Customers at end of June	2010 Forecast kWh Units	2010 Forecast kVA Units	2010 Proposed Rates (Full Precision) ($)	2010 Proposed Rates ($)	% Difference	2010 Annual Revenue at Proposed Rates (Full Precision) ($)	2010 Annual Revenue at Proposed Rates ($)	$ Difference	% Difference	2010 Base Revenue Requirement ($)	$ Difference from Revenue at Proposed Rates	% Difference
2	**RESIDENTIAL**														
3	Monthly Customer Charge		679,914			18.137104	18.14	0.0%	150,035,294	150,059,255	23,960	0.0%			
4	Distribution Charge			5,785,918,437		0.017689	0.0177	0.1%	102,347,478	102,410,756	63,278	0.1%			
5	Cust+Distribution Only								252,382,772	252,470,011	87,238	0.0%	252,382,804	87,207	0.0%
6															
7	**GENERAL SERVICE (< 50 kW)**														
8	Monthly Customer Charge		66,823			22.838510	22.84	0.0%	18,567,931	18,569,142	1,211	0.0%			
9	Distribution Charge			2,574,909,409		0.022688	0.0227	0.1%	58,420,374	58,450,444	30,070	0.1%			
10	Cust+Distribution Only								76,988,304	77,019,586	31,281	0.0%	76,988,383	31,203	0.0%
11															
12	**GENERAL SERVICE (50 - 1000 kW)**														
13	Monthly Customer Charge		11,583			34.012538	34.01	0.0%	4,793,407	4,793,049	-358	0.0%			
14	Distribution Charge				25,358,216	5.626261	5.63	0.1%	144,653,499	144,749,628	96,130	0.1%			
15	Cust+Distribution Only								149,446,906	149,542,678	95,772	0.1%	149,446,767	95,911	0.1%
16	**GENERAL SERVICE (1,000 - 5000 kW)**														
17	Monthly Customer Charge		543			691.113621	691.11	0.0%	4,566,314	4,566,290	-24	0.0%			
18	Distribution Charge				11,792,136	4.754395	4.75	-0.1%	56,843,149	56,790,600	-52,550	-0.1%			
19	Cust+Distribution Only								61,409,464	61,356,890	-52,574	-0.1%	61,408,992	-52,102	-0.1%
20															
21	**LARGE USERS**														
22	Monthly Customer Charge		49			2,277.324037	2,277.32	0.0%	1,357,665	1,357,662	-2	0.0%			
23	Distribution Charge				5,452,850	4.359423	4.36	0.0%	24,101,441	24,104,628	3,187	0.0%			
24	Cust+Distribution Only								25,459,105	25,462,290	3,185	0.0%	25,459,105	3,185	0.0%
25															
26	**STREET LIGHTING**														
27	Monthly Customer Charge		159,861			1.120774	1.12	-0.1%	2,179,877	2,178,373	-1,505	-0.1%			
28	Distribution Charge				317,526	13.095748	13.10	0.0%	4,215,998	4,217,367	1,369	0.0%			
29	Cust+Distribution Only								6,395,876	6,395,740	-136	0.0%	6,395,876	-136	0.0%
30															
31	**SMALL UNMETERED SCATTERED LOADS**														
32	Admin/Processing		1,466			3.741898	3.74	-0.1%	66,738	66,704	-34	-0.1%			
33	Service Charge per Site		17,721			0.369930	0.37	0.0%	79,760	79,775	15	0.0%			
34	Distribution Charge			58,219,008		0.033553	0.0336		1,953,427	1,956,159	2,732	0.1%			
35	Cust+Distribution Only								2,099,924	2,102,637	2,713	0.1%	2,099,927	2,710	0.1%
36															
37	**TRANSFORMER ALLOWANCE**														
38		- Annual			19,196,795	-0.62	-0.62	0.0%	-12,067,319	-12,067,319	0	0.0%	-12,067,319	0	0.0%
39															
40	**Sum of Customer, Distribution Charges and Transformer Allowance (LV Charges not included in rates due to rounding)**								**562,115,033**	**562,282,513**	**167,480**		**562,114,535**	**167,978**	**0.0%**
41	**Other revenue Offsets**									**24,283,140**					
42	**2010 Total Operating Revenue**									**586,565,653**					
43	**2010 Service Revenue Requirement**									**586,653,105**					
44	**Difference (Total Operating Revenue - Service Revenue Requirement)**									**-87,452**					
45															
46															

OTHER REGULATED CHARGES

Other regulated charges are exclusive of the distribution monthly service charges, volumetric rates, and specific service charges. They include Regulated Price Plan ("RPP") Administration Charge, Retail Service Charges and Non-competitive Energy Charges. The OEB, in its Distribution Rate Handbook ("DRH") issued on January 5, 2001, sets uniform rates and charges for all these services except the transmission service charges.

RPP ADMINISTRATION CHARGE

In the 2006 Electricity Distribution Rates ("EDR"), the OEB renamed SSS Administration Charge to RPP Administration Charge. THESL applies a standard charge of $0.25 per 30 days per customer.

RETAIL SERVICE CHARGES

Retail Service Charges include contract and administration charges, Distributor-consolidated Billing Charge, Retailer-consolidated Billing Credit, Service Transaction Requests and Processing Charges. THESL applies the standard charges for Retail Service Charges in accordance with the DRH issued on January 5, 2001.

NON-COMPETIVE ELECTRICITY CHARGES

In the DRH, the OEB set a province-wide Wholesale Market Service Charge and provided a methodology for LDCs to determine the Retail Transmission Service Rates. THESL also established two Retail Settlement Variance Accounts, one for network service and another one for connection service ("$RSVA_{Network}$" and "$RSVA_{Connection}$") for the purpose of recording the difference between the amount THESL is billed by the IESO and the amount THESL bills to its customers at the approved Retail Transmission Service Rates.

Retail Transmission Service Rates

As part of the 2006 EDR, the OEB issued guidelines in a letter dated July 5, 2005, for LDCs to determine whether adjustment to the Retail Transmission Service Rates is necessary. THESL followed the guidelines and examined the monthly charges in the transmission variance accounts and found the $RSVA_{Connection}$ showed a consistent pattern of over-recovery. As a result, THESL applied to reduce the Retail Transmission Connection Rates to keep the revenues more closely in line with costs.

THESL has again examined the monthly charges in both transmission variance accounts. The $RSVA_{Network}$ exhibits a random pattern in the historical years and averages less than one-percent under-recovery in the forecast years. The $RSVA_{Connection}$ exhibits a random pattern after the rate reduction effective May 1, 2006.

Since Hydro One Transmission has applied for transmission rate changes (EB-2005-0501) that could affect THESL costs, THESL is not proposing any changes to its retail transmission rates at this time, (except to combine the two 50-1000 kW classes for the rate year. See Exhibit M1, Tab 1, Schedule 1.), but will update for any decision issued by the OEB. The historical $RSVA_{Network}$ and $RSVA_{Connection}$ charges are shown in Exhibit N1, Tab 1, Schedule 2. The forecast network and connection revenues, costs and RSVA charges are shown in Exhibit N1, Tab 1, Schedule 3.

Table 1: Historical RSVA Charges for Network and Connection Services

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
1		RSVA-Network		RSVA-Connection	
2	Month	Monthly Charges	Annual Charges	Monthy Charges	Annual Charges
3	May-02	72,933		(438,594)	
4	Jun-02	1,758,124		832,906	
5	Jul-02	194,213		(289,996)	
6	Aug-02	(148,242)		(543,551)	
7	Sep-02	1,449,216		803,156	
8	Oct-02	(186,544)		(376,054)	
9	Nov-02	(200,273)		(458,406)	
10	Dec-02	(836,262)	2,103,165	(997,683)	(1,468,222)
11	Jan-03	(850,024)		(974,314)	
12	Feb-03	988,688		436,892	
13	Mar-03	(507,231)		(721,533)	
14	Apr-03	(210,451)		(444,672)	
15	May-03	(1,055,732)		(948,306)	
16	Jun-03	2,177,873		1,168,124	
17	Jul-03	305,749		(188,599)	
18	Aug-03	495,379		(158,260)	
19	Sep-03	(77,180)		523,430	
20	Oct-03	(1,134,435)		(1,210,286)	
21	Nov-03	(321,096)		(413,513)	
22	Dec-03	(920,343)	(1,108,803)	(1,045,051)	(3,976,089)
23	Jan-04	(644,662)		(928,803)	
24	Feb-04	312,547		(139,923)	
25	Mar-04	(971,332)		(1,075,158)	
26	Apr-04	(563,103)		(755,917)	
27	May-04	(383,475)		(848,151)	
28	Jun-04	1,508,361		730,920	
29	Jul-04	938,170		110,442	
30	Aug-04	422,061		(195,131)	
31	Sep-04	22,280		(230,735)	
32	Oct-04	(1,219,997)		(1,068,082)	
33	Nov-04	(205,429)		(163,803)	
34	Dec-04	(170,934)	(955,511)	(922,874)	(5,487,216)
35	Jan-05	1,263,969		1,519,416	
36	Feb-05	(834,778)		(1,456,842)	
37	Mar-05	(1,247,705)		(1,633,655)	
38	Apr-05	(981,107)		1,480,871	
39	May-05	(1,163,704)		(3,375,894)	
40	Jun-05	1,173,101		170,509	
41	Jul-05	(104,791)		(228,979)	
42	Aug-05	637,579		(41,780)	
43	Sep-05	1,587,754		575,769	
44	Oct-05	(812,264)		(534,243)	
45	Nov-05	234,379		(65,107)	
46	Dec-05	(482,181)	(729,747)	(1,377,980)	(4,967,914)
47	Jan-06	(648,511)		(657,004)	
48	Feb-06	788,739		82,678	
49	Mar-06	(1,166,896)		(1,288,766)	
50	Apr-06	(278,356)		(22,107)	
51	May-06	1,103,792		336,590	
52	Jun-06	2,011,033		1,126,024	
53	Jul-06	(1,198,376)		(1,067,332)	
54	Aug-06	3,215,992		2,935,322	
55	Sep-06	(23,540)		(376,606)	
56	Oct-06	(1,143,444)		(456,402)	
57	Nov-06	(32,647)		90,959	
58	Dec-06	(476,870)	2,150,917	(753,480)	(50,124)

Forecast Transmission Revenue, Costs and RSVA

Table 1: 2008 ($)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	Month	Revenue at Retail Rates		Costs (Revenue at Wholesale Rates)		RSVA (Costs - Revenue)	
2		Network	Connection	Network	Connection	Network	Connection
3	January	12,821,852	9,779,674	11,937,343	9,173,224	-884,509	-606,450
4	February	11,108,808	8,514,856	11,298,607	8,749,412	189,799	234,556
5	March	11,936,563	9,118,009	11,024,642	8,473,691	-911,921	-644,318
6	April	10,967,771	8,438,358	10,341,443	8,094,750	-626,327	-343,608
7	May	11,176,413	8,589,194	11,078,471	8,527,577	-97,942	-61,617
8	June	11,655,865	8,924,344	12,915,012	9,855,451	1,259,147	931,106
9	July	12,738,087	9,752,664	13,363,608	10,182,417	625,521	429,753
10	August	12,461,335	9,547,945	12,948,544	9,935,762	487,209	387,817
11	September	10,958,954	8,365,295	11,668,099	8,989,359	709,145	624,064
12	October	11,632,868	8,862,773	10,506,124	8,178,506	-1,126,744	-684,267
13	November	11,101,485	8,474,579	10,953,368	8,477,431	-148,116	2,852
14	December	12,795,330	9,753,255	11,746,634	9,011,560	-1,048,696	-741,696
15	Total	141,355,330	108,120,946	139,781,896	107,649,140	-1,573,434	-471,806

Table 2: 2009 ($)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	Month	Revenue at Retail Rates		Costs (Revenue at Wholesale Rates)		RSVA (Costs - Revenue)	
2		Network	Connection	Network	Connection	Network	Connection
3	January	12,835,977	9,790,980	11,931,701	9,168,606	-904,276	-622,374
4	February	10,776,148	8,263,582	11,563,676	8,968,703	787,528	705,120
5	March	12,116,834	9,255,760	11,172,570	8,595,412	-944,264	-660,348
6	April	10,989,599	8,455,911	10,343,845	8,096,769	-645,754	-359,142
7	May	11,195,202	8,603,551	11,077,616	8,526,873	-117,586	-76,678
8	June	11,746,727	8,993,935	13,028,940	9,947,663	1,282,212	953,727
9	July	12,736,276	9,749,980	13,408,069	10,218,283	671,792	468,303
10	August	12,459,583	9,545,241	12,992,938	9,971,877	533,355	426,636
11	September	10,994,581	8,392,677	11,716,733	9,029,319	722,152	636,643
12	October	11,651,177	8,876,850	10,505,290	8,177,809	-1,145,887	-699,041
13	November	11,120,174	8,490,168	10,950,184	8,474,793	-169,990	-15,375
14	December	12,867,714	9,809,041	11,793,272	9,049,712	-1,074,442	-759,329
15	Total	141,489,992	108,227,677	140,484,834	108,225,819	-1,005,158	-1,858

Table 3: 2010 ($)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	Month	Revenue at Retail Rates		Costs (Revenue at Wholesale Rates)		RSVA (Costs - Revenue)	
2		Network	Connection	Network	Connection	Network	Connection
3	January	12,853,513	9,805,344	11,926,070	9,163,998	-927,443	-641,346
4	February	10,851,759	8,322,699	11,613,061	9,009,558	761,301	686,859
5	March	12,151,934	9,283,090	11,182,411	8,603,510	-969,523	-679,580
6	April	11,014,872	8,476,418	10,346,019	8,098,596	-668,853	-377,823
7	May	11,214,976	8,619,263	11,074,644	8,524,425	-140,333	-94,838
8	June	11,801,613	9,037,037	13,081,576	9,990,266	1,279,963	953,228
9	July	12,718,076	9,736,493	13,398,291	10,210,396	680,215	473,904
10	August	12,554,624	9,618,004	13,098,516	10,057,764	543,892	439,760
11	September	11,052,712	8,438,047	11,767,122	9,070,722	714,410	632,674
12	October	11,672,008	8,893,837	10,504,503	8,177,152	-1,167,504	-716,685
13	November	11,148,962	8,514,085	10,952,152	8,476,423	-196,810	-37,662
14	December	12,922,099	9,852,376	11,820,168	9,071,714	-1,101,931	-780,662
15	Total	141,957,147	108,596,695	140,764,531	108,454,523	-1,192,616	-142,172

2008 - 2010 Distribution Bill Impact

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25
				2007 Rates				**2008 Rates**				**2009 Rates**				**2010 Rates**				**2008 Increase**		**2009 Increase**		**2010 Increase**	
1	**kWh**	**kW**	**kVA**	**Customer ($)**	**Volumetric ($)**		**Monthly Dist Bill ($)**	**Customer ($)**	**Volumetric ($)**		**Monthly Dist Bill ($)**	**Customer ($)**	**Volumetric ($)**		**Monthly Dist Bill ($)**	**Customer ($)**	**Volumetric ($)**		**Monthly Dist Bill ($)**	**$**	**%**	**$**	**%**	**$**	**%**
2	**Residential**																								
3	100			12.00	0.0155		13.55	14.85	0.0173		16.58	16.85	0.0174		18.59	18.14	0.0177		19.91	**3.03**	**22.4%**	**2.01**	**12.1%**	**1.32**	**7.1%**
4	250			12.00	0.0155		15.88	14.85	0.0173		19.18	16.85	0.0174		21.20	18.14	0.0177		22.57	**3.30**	**20.8%**	**2.03**	**10.6%**	**1.37**	**6.4%**
5	500			12.00	0.0155		19.75	14.85	0.0173		23.50	16.85	0.0174		25.55	18.14	0.0177		26.99	**3.75**	**19.0%**	**2.05**	**8.7%**	**1.44**	**5.6%**
6	750			12.00	0.0155		23.63	14.85	0.0173		27.83	16.85	0.0174		29.90	18.14	0.0177		31.42	**4.20**	**17.8%**	**2.08**	**7.5%**	**1.52**	**5.1%**
7	1,000			12.00	0.0155		27.50	14.85	0.0173		32.15	16.85	0.0174		34.25	18.14	0.0177		35.84	**4.65**	**16.9%**	**2.10**	**6.5%**	**1.59**	**4.6%**
8	1,500			12.00	0.0155		35.25	14.85	0.0173		40.80	16.85	0.0174		42.95	18.14	0.0177		44.69	**5.55**	**15.7%**	**2.15**	**5.3%**	**1.74**	**4.1%**
9	2,000			12.00	0.0155		43.00	14.85	0.0173		49.45	16.85	0.0174		51.65	18.14	0.0177		53.54	**6.45**	**15.0%**	**2.20**	**4.4%**	**1.89**	**3.7%**
10	**GS<50 kW**																								
11	1,000			16.07	0.0185		34.57	19.37	0.0210		40.37	21.44	0.0218		43.24	22.84	0.0227		45.54	**5.80**	**16.8%**	**2.87**	**7.1%**	**2.30**	**5.3%**
12	5,000			16.07	0.0185		108.57	19.37	0.0210		124.37	21.44	0.0218		130.44	22.84	0.0227		136.34	**15.80**	**14.6%**	**6.07**	**4.9%**	**5.90**	**4.5%**
13	10,000			16.07	0.0185		201.07	19.37	0.0210		229.37	21.44	0.0218		239.44	22.84	0.0227		249.84	**28.30**	**14.1%**	**10.07**	**4.4%**	**10.40**	**4.3%**
14	20,000			16.07	0.0185		386.07	19.37	0.0210		439.37	21.44	0.0218		457.44	22.84	0.0227		476.84	**53.30**	**13.8%**	**18.07**	**4.1%**	**19.40**	**4.2%**
15	**GS 50-1000 kW**																								
16	30,000	100	100	25.82	4.98		523.82	29.78	5.40		569.78	32.69	5.58		590.69	34.01	5.63		597.01	**45.96**	**8.8%**	**20.91**	**3.7%**	**6.32**	**1.1%**
17	40,000	100	100	25.82	4.98		523.82	29.78	5.40		569.78	32.69	5.58		590.69	34.01	5.63		597.01	**45.96**	**8.8%**	**20.91**	**3.7%**	**6.32**	**1.1%**
18	150,000	500	556	25.82	4.98		2,792.49	29.78	5.40		3,029.78	32.69	5.58		3,132.69	34.01	5.63		3,161.79	**237.29**	**8.5%**	**102.91**	**3.4%**	**29.10**	**0.9%**
19	200,000	500	556	25.82	4.98		2,792.49	29.78	5.40		3,029.78	32.69	5.58		3,132.69	34.01	5.63		3,161.79	**237.29**	**8.5%**	**102.91**	**3.4%**	**29.10**	**0.9%**
20	270,000	900	1,000	25.82	4.98		5,005.82	29.78	5.40		5,429.78	32.69	5.58		5,612.69	34.01	5.63		5,664.01	**423.96**	**8.5%**	**182.91**	**3.4%**	**51.32**	**0.9%**
21	360,000	900	1,000	25.82	4.98		5,005.82	29.78	5.40		5,429.78	32.69	5.58		5,612.69	34.01	5.63		5,664.01	**423.96**	**8.5%**	**182.91**	**3.4%**	**51.32**	**0.9%**
22	450,000	900	1,000	25.82	4.98		5,005.82	29.78	5.40		5,429.78	32.69	5.58		5,612.69	34.01	5.63		5,664.01	**423.96**	**8.5%**	**182.91**	**3.4%**	**51.32**	**0.9%**
23	**GS 1000-5000 kW**																								
24	300,000	1,000	1,111	717.42	4.16		5,339.64	725.80	4.52		5,748.02	705.33	4.69		5,916.44	691.11	4.75		5,968.89	**408.38**	**7.6%**	**168.42**	**2.9%**	**52.45**	**0.9%**
25	400,000	1,000	1,111	717.42	4.16		5,339.64	725.80	4.52		5,748.02	705.33	4.69		5,916.44	691.11	4.75		5,968.89	**408.38**	**7.6%**	**168.42**	**2.9%**	**52.45**	**0.9%**
26	500,000	1,000	1,111	717.42	4.16		5,339.64	725.80	4.52		5,748.02	705.33	4.69		5,916.44	691.11	4.75		5,968.89	**408.38**	**7.6%**	**168.42**	**2.9%**	**52.45**	**0.9%**
27	600,000	2,000	2,222	717.42	4.16		9,961.86	725.80	4.52		10,770.24	705.33	4.69		11,127.55	691.11	4.75		11,246.67	**808.38**	**8.1%**	**357.31**	**3.3%**	**119.11**	**1.1%**
28	800,000	2,000	2,222	717.42	4.16		9,961.86	725.80	4.52		10,770.24	705.33	4.69		11,127.55	691.11	4.75		11,246.67	**808.38**	**8.1%**	**357.31**	**3.3%**	**119.11**	**1.1%**
29	1,000,000	2,000	2,222	717.42	4.16		9,961.86	725.80	4.52		10,770.24	705.33	4.69		11,127.55	691.11	4.75		11,246.67	**808.38**	**8.1%**	**357.31**	**3.3%**	**119.11**	**1.1%**
30	**Large Use**																								
31	1,500,000	5,000	5,556	2,758.30	3.55		22,480.52	2,883.81	3.97		24,939.37	2,639.01	4.20		25,972.34	2,277.32	4.36		26,499.54	**2,458.84**	**10.9%**	**1,032.98**	**4.1%**	**527.20**	**2.0%**
32	2,000,000	5,000	5,556	2,758.30	3.55		22,480.52	2,883.81	3.97		24,939.37	2,639.01	4.20		25,972.34	2,277.32	4.36		26,499.54	**2,458.84**	**10.9%**	**1,032.98**	**4.1%**	**527.20**	**2.0%**
33	2,500,000	5,000	5,556	2,758.30	3.55		22,480.52	2,883.81	3.97		24,939.37	2,639.01	4.20		25,972.34	2,277.32	4.36		26,499.54	**2,458.84**	**10.9%**	**1,032.98**	**4.1%**	**527.20**	**2.0%**
34	3,000,000	10,000	11,111	2,758.30	3.55		42,202.74	2,883.81	3.97		46,994.92	2,639.01	4.20		49,305.68	2,277.32	4.36		50,721.76	**4,792.18**	**11.4%**	**2,310.76**	**4.9%**	**1,416.09**	**2.9%**
35	4,000,000	10,000	11,111	2,758.30	3.55		42,202.74	2,883.81	3.97		46,994.92	2,639.01	4.20		49,305.68	2,277.32	4.36		50,721.76	**4,792.18**	**11.4%**	**2,310.76**	**4.9%**	**1,416.09**	**2.9%**
36	5,000,000	10,000	11,111	2,758.30	3.55		42,202.74	2,883.81	3.97		46,994.92	2,639.01	4.20		49,305.68	2,277.32	4.36		50,721.76	**4,792.18**	**11.4%**	**2,310.76**	**4.9%**	**1,416.09**	**2.9%**
37	**Street Lighting**	connections	mthly kVA																						
38	9,182,014	159,861	26,461	0.26	3.60		136,821.66	0.66	8.75		337,037.64	0.89	10.82		428,578.90	1.12	13.10		525,676.87	**200,215.98**	**146.3%**	**91,541.27**	**27.2%**	**97,097.97**	**22.7%**
39	365	1	1	0.26	3.60		3.86	0.66	8.75		9.41	0.89	10.82		11.71	1.12	13.10		14.22	**5.55**	**143.8%**	**2.30**	**24.4%**	**2.51**	**21.4%**
40	**Unmetered Scattered Loads**	connections				Connection				Connection				Connection				Connection							
41	4,829,242	1,466	17,721	1.99	0.0180	0.29	94,982.79	2.96	0.0259	0.33	135,264.66	3.42	0.0299	0.35	155,610.41	3.74	0.0336	0.37	174,302.15	**40,281.87**	**42.4%**	**20,345.75**	**15.0%**	**18,691.74**	**12.0%**
42	365	1	1	1.99	0.0180	0.29	8.85	2.96	0.0259	0.33	12.74	3.42	0.0299	0.35	14.68	3.74	0.0336	0.37	16.37	**3.89**	**44.0%**	**1.94**	**15.2%**	**1.69**	**11.5%**

2008 - 2010 Rate Rider Bill Impact

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21
				2007 Rates			2008 Rates			2009 Rates			2010 Rates			2008 Increase		2009 Increase		2010 Increase	
1	kWh	kW	kVA	Smart Meter ($)	Rate Rider($)	Reg Asset Recovery ($)	Smart Meter ($)	Rate Rider($)	Reg Asset Recovery ($)	Smart Meter ($)	Rate Rider($)	Reg Asset Recovery ($)	Smart Meter ($)	Rate Rider($)	Reg Asset Recovery ($)	$	%	$	%	$	%
2	**Residential**																				
3	100			0.68	0.0032	1.00	0.00	-0.0010	-0.10	0.00	0.0000	0.00	0.00	0.0000	0.00	**-1.10**	**-110%**	**0.10**	**-100%**	**0.00**	**0%**
4	250			0.68	0.0032	1.48	0.00	-0.0010	-0.25	0.00	0.0000	0.00	0.00	0.0000	0.00	**-1.73**	**-117%**	**0.25**	**-100%**	**0.00**	**0%**
5	500			0.68	0.0032	2.28	0.00	-0.0010	-0.50	0.00	0.0000	0.00	0.00	0.0000	0.00	**-2.78**	**-122%**	**0.50**	**-100%**	**0.00**	**0%**
6	750			0.68	0.0032	3.08	0.00	-0.0010	-0.75	0.00	0.0000	0.00	0.00	0.0000	0.00	**-3.83**	**-124%**	**0.75**	**-100%**	**0.00**	**0%**
7	1,000			0.68	0.0032	3.88	0.00	-0.0010	-1.00	0.00	0.0000	0.00	0.00	0.0000	0.00	**-4.88**	**-126%**	**1.00**	**-100%**	**0.00**	**0%**
8	1,500			0.68	0.0032	5.48	0.00	-0.0010	-1.50	0.00	0.0000	0.00	0.00	0.0000	0.00	**-6.98**	**-127%**	**1.50**	**-100%**	**0.00**	**0%**
9	2,000			0.68	0.0032	7.08	0.00	-0.0010	-2.00	0.00	0.0000	0.00	0.00	0.0000	0.00	**-9.08**	**-128%**	**2.00**	**-100%**	**0.00**	**0%**
10	**GS<50 kW**																				
11	1,000			0.68	0.0015	2.18	0.00	-0.0010	-1.00	0.00	0.0000	0.00	0.00	0.0000	0.00	**-3.18**	**-146%**	**1.00**	**-100%**	**0.00**	**0%**
12	5,000			0.68	0.0015	8.18	0.00	-0.0010	-5.00	0.00	0.0000	0.00	0.00	0.0000	0.00	**-13.18**	**-161%**	**5.00**	**-100%**	**0.00**	**0%**
13	10,000			0.68	0.0015	15.68	0.00	-0.0010	-10.00	0.00	0.0000	0.00	0.00	0.0000	0.00	**-25.68**	**-164%**	**10.00**	**-100%**	**0.00**	**0%**
14	20,000			0.68	0.0015	30.68	0.00	-0.0010	-20.00	0.00	0.0000	0.00	0.00	0.0000	0.00	**-50.68**	**-165%**	**20.00**	**-100%**	**0.00**	**0%**
15	**GS 50-1000 kW**																				
16	30,000	100	100	0.68	0.09	9.68	0.00	-0.32	-32.00	0.00	0.00	0.00	0.00	0.00	0.00	**-41.68**	**-431%**	**32.00**	**-100%**	**0.00**	**0%**
17	40,000	100	100	0.68	0.09	9.68	0.00	-0.32	-32.00	0.00	0.00	0.00	0.00	0.00	0.00	**-41.68**	**-431%**	**32.00**	**-100%**	**0.00**	**0%**
18	150,000	500	556	0.68	0.09	50.68	0.00	-0.32	-177.78	0.00	0.00	0.00	0.00	0.00	0.00	**-228.46**	**-451%**	**177.78**	**-100%**	**0.00**	**0%**
19	200,000	500	556	0.68	0.09	50.68	0.00	-0.32	-177.78	0.00	0.00	0.00	0.00	0.00	0.00	**-228.46**	**-451%**	**177.78**	**-100%**	**0.00**	**0%**
20	270,000	900	1,000	0.68	0.09	90.68	0.00	-0.32	-320.00	0.00	0.00	0.00	0.00	0.00	0.00	**-410.68**	**-453%**	**320.00**	**-100%**	**0.00**	**0%**
21	360,000	900	1,000	0.68	0.09	90.68	0.00	-0.32	-320.00	0.00	0.00	0.00	0.00	0.00	0.00	**-410.68**	**-453%**	**320.00**	**-100%**	**0.00**	**0%**
22	450,000	900	1,000	0.68	0.09	90.68	0.00	-0.32	-320.00	0.00	0.00	0.00	0.00	0.00	0.00	**-410.68**	**-453%**	**320.00**	**-100%**	**0.00**	**0%**
23	**GS 1000-5000 kW**																				
24	300,000	1,000	1,111	0.68	0.07	78.46	0.00	-0.36	-400.00	0.00	0.00	0.00	0.00	0.00	0.00	**-478.46**	**-610%**	**400.00**	**-100%**	**0.00**	**0%**
25	400,000	1,000	1,111	0.68	0.07	78.46	0.00	-0.36	-400.00	0.00	0.00	0.00	0.00	0.00	0.00	**-478.46**	**-610%**	**400.00**	**-100%**	**0.00**	**0%**
26	500,000	1,000	1,111	0.68	0.07	78.46	0.00	-0.36	-400.00	0.00	0.00	0.00	0.00	0.00	0.00	**-478.46**	**-610%**	**400.00**	**-100%**	**0.00**	**0%**
27	600,000	2,000	2,222	0.68	0.07	156.24	0.00	-0.36	-800.00	0.00	0.00	0.00	0.00	0.00	0.00	**-956.24**	**-612%**	**800.00**	**-100%**	**0.00**	**0%**
28	800,000	2,000	2,222	0.68	0.07	156.24	0.00	-0.36	-800.00	0.00	0.00	0.00	0.00	0.00	0.00	**-956.24**	**-612%**	**800.00**	**-100%**	**0.00**	**0%**
29	1,000,000	2,000	2,222	0.68	0.07	156.24	0.00	-0.36	-800.00	0.00	0.00	0.00	0.00	0.00	0.00	**-956.24**	**-612%**	**800.00**	**-100%**	**0.00**	**0%**
30	**Large Use**																				
31	1,500,000	5,000	5,556	0.68	0.07	389.57	0.00	-0.47	-2,611.11	0.00	0.00	0.00	0.00	0.00	0.00	**-3,000.68**	**-770%**	**2,611.11**	**-100%**	**0.00**	**0%**
32	2,000,000	5,000	5,556	0.68	0.07	389.57	0.00	-0.47	-2,611.11	0.00	0.00	0.00	0.00	0.00	0.00	**-3,000.68**	**-770%**	**2,611.11**	**-100%**	**0.00**	**0%**
33	2,500,000	5,000	5,556	0.68	0.07	389.57	0.00	-0.47	-2,611.11	0.00	0.00	0.00	0.00	0.00	0.00	**-3,000.68**	**-770%**	**2,611.11**	**-100%**	**0.00**	**0%**
34	3,000,000	10,000	11,111	0.68	0.07	778.46	0.00	-0.47	-5,222.22	0.00	0.00	0.00	0.00	0.00	0.00	**-6,000.68**	**-771%**	**5,222.22**	**-100%**	**0.00**	**0%**
35	4,000,000	10,000	11,111	0.68	0.07	778.46	0.00	-0.47	-5,222.22	0.00	0.00	0.00	0.00	0.00	0.00	**-6,000.68**	**-771%**	**5,222.22**	**-100%**	**0.00**	**0%**
36	5,000,000	10,000	11,111	0.68	0.07	778.46	0.00	-0.47	-5,222.22	0.00	0.00	0.00	0.00	0.00	0.00	**-6,000.68**	**-771%**	**5,222.22**	**-100%**	**0.00**	**0%**
37	**Street Lighting**	connections	mthly kVA																		
38	9,182,014	159,861	26,461	0.00	0.08	2,116.84	0.00	-0.30	-7,938.15	0.00	0.00	0.00	0.00	0.00	0.00	**-10,054.99**	**-475%**	**7,938.15**	**-100%**	**0.00**	**0%**
39	365	1	1	0.00	0.08	0.08	0.00	-0.30	-0.30	0.00	0.00	0.00	0.00	0.00	0.00	**-0.38**	**-475%**	**0.30**	**-100%**	**0.00**	**0%**
40	**Unmetered Scattered Loads**		connections																		
41	4,829,242	1,466	17,721	0.00	0.0014	6,760.94	0.00	-0.0009	-4,346.32	0.00	0.0000	0.00	0.00	0.0000	0.00	**-11,107.26**	**-164%**	**4,346.32**	**-100%**	**0.00**	**0%**
42	365	1	1	0.00	0.0014	0.51	0.00	-0.0009	-0.33	0.00	0.0000	0.00	0.00	0.0000	0.00	**-0.84**	**-164%**	**0.33**	**-100%**	**0.00**	**0%**

2008 - 2010 Distribution and Rate Rider Bill Impact

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21
				Monthly Bills at 2007 Approved Rates			**Monthly Bills at Proposed 2008 Rates**			**Monthly Bills at Proposed 2009 Rates**			**Monthly Bills at Proposed 2010 Rates**			**2008 Increase**		**2009 Increase**		**2010 Increase**	
1	**kWh**	**kW**	**kVA**	**Distribution ($)**	**Reg Asset Recovery ($)**	**Total ($)**	**Distribution ($)**	**Reg Asset Recovery ($)**	**Total ($)**	**Distribution ($)**	**Reg Asset Recovery ($)**	**Total ($)**	**Distribution ($)**	**Reg Asset Recovery ($)**	**Total ($)**	**$**	**%**	**$**	**%**	**$**	**%**
2	**Residential**																				
3	100			13.55	1.00	14.55	16.58	-0.10	16.48	18.59	0.00	18.59	19.91	0.00	19.91	**1.93**	**13.3%**	**2.11**	**12.8%**	**1.32**	**7.1%**
4	250			15.88	1.48	17.36	19.18	-0.25	18.93	21.20	0.00	21.20	22.57	0.00	22.57	**1.57**	**9.0%**	**2.28**	**12.0%**	**1.37**	**6.4%**
5	500			19.75	2.28	22.03	23.50	-0.50	23.00	25.55	0.00	25.55	26.99	0.00	26.99	**0.97**	**4.4%**	**2.55**	**11.1%**	**1.44**	**5.6%**
6	750			23.63	3.08	26.71	27.83	-0.75	27.08	29.90	0.00	29.90	31.42	0.00	31.42	**0.37**	**1.4%**	**2.83**	**10.4%**	**1.52**	**5.1%**
7	1,000			27.50	3.88	31.38	32.15	-1.00	31.15	34.25	0.00	34.25	35.84	0.00	35.84	**-0.23**	**-0.7%**	**3.10**	**10.0%**	**1.59**	**4.6%**
8	1,500			35.25	5.48	40.73	40.80	-1.50	39.30	42.95	0.00	42.95	44.69	0.00	44.69	**-1.43**	**-3.5%**	**3.65**	**9.3%**	**1.74**	**4.1%**
9	2,000			43.00	7.08	50.08	49.45	-2.00	47.45	51.65	0.00	51.65	53.54	0.00	53.54	**-2.63**	**-5.3%**	**4.20**	**8.9%**	**1.89**	**3.7%**
10	**GS<50 kW**																				
11	1,000			34.57	2.18	36.75	40.37	-1.00	39.37	43.24	0.00	43.24	45.54	0.00	45.54	**2.62**	**7.1%**	**3.87**	**9.8%**	**2.30**	**5.3%**
12	5,000			108.57	8.18	116.75	124.37	-5.00	119.37	130.44	0.00	130.44	136.34	0.00	136.34	**2.62**	**2.2%**	**11.07**	**9.3%**	**5.90**	**4.5%**
13	10,000			201.07	15.68	216.75	229.37	-10.00	219.37	239.44	0.00	239.44	249.84	0.00	249.84	**2.62**	**1.2%**	**20.07**	**9.1%**	**10.40**	**4.3%**
14	20,000			386.07	30.68	416.75	439.37	-20.00	419.37	457.44	0.00	457.44	476.84	0.00	476.84	**2.62**	**0.6%**	**38.07**	**9.1%**	**19.40**	**4.2%**
15	**GS 50-1000 kW**																				
16	30,000	100	100	523.82	9.68	533.50	569.78	-32.00	537.78	590.69	0.00	590.69	597.01	0.00	597.01	**4.28**	**0.8%**	**52.91**	**9.8%**	**6.32**	**1.1%**
17	40,000	100	100	523.82	9.68	533.50	569.78	-32.00	537.78	590.69	0.00	590.69	597.01	0.00	597.01	**4.28**	**0.8%**	**52.91**	**9.8%**	**6.32**	**1.1%**
18	150,000	500	556	2,792.49	50.68	2,843.17	3,029.78	-177.78	2,852.00	3,132.69	0.00	3,132.69	3,161.79	0.00	3,161.79	**8.84**	**0.3%**	**280.69**	**9.8%**	**29.10**	**0.9%**
19	200,000	500	556	2,792.49	50.68	2,843.17	3,029.78	-177.78	2,852.00	3,132.69	0.00	3,132.69	3,161.79	0.00	3,161.79	**8.84**	**0.3%**	**280.69**	**9.8%**	**29.10**	**0.9%**
20	270,000	900	1,000	5,005.82	90.68	5,096.50	5,429.78	-320.00	5,109.78	5,612.69	0.00	5,612.69	5,664.01	0.00	5,664.01	**13.28**	**0.3%**	**502.91**	**9.8%**	**51.32**	**0.9%**
21	360,000	900	1,000	5,005.82	90.68	5,096.50	5,429.78	-320.00	5,109.78	5,612.69	0.00	5,612.69	5,664.01	0.00	5,664.01	**13.28**	**0.3%**	**502.91**	**9.8%**	**51.32**	**0.9%**
22	450,000	900	1,000	5,005.82	90.68	5,096.50	5,429.78	-320.00	5,109.78	5,612.69	0.00	5,612.69	5,664.01	0.00	5,664.01	**13.28**	**0.3%**	**502.91**	**9.8%**	**51.32**	**0.9%**
23	**GS 1000-5000 kW**																				
24	300,000	1,000	1,111	5,339.64	78.46	5,418.10	5,748.02	-400.00	5,348.02	5,916.44	0.00	5,916.44	5,968.89	0.00	5,968.89	**-70.08**	**-1.3%**	**568.42**	**10.6%**	**52.45**	**0.9%**
25	400,000	1,000	1,111	5,339.64	78.46	5,418.10	5,748.02	-400.00	5,348.02	5,916.44	0.00	5,916.44	5,968.89	0.00	5,968.89	**-70.08**	**-1.3%**	**568.42**	**10.6%**	**52.45**	**0.9%**
26	500,000	1,000	1,111	5,339.64	78.46	5,418.10	5,748.02	-400.00	5,348.02	5,916.44	0.00	5,916.44	5,968.89	0.00	5,968.89	**-70.08**	**-1.3%**	**568.42**	**10.6%**	**52.45**	**0.9%**
27	600,000	2,000	2,222	9,961.86	156.24	10,118.10	10,770.24	-800.00	9,970.24	11,127.55	0.00	11,127.55	11,246.67	0.00	11,246.67	**-147.86**	**-1.5%**	**1,157.31**	**11.6%**	**119.11**	**1.1%**
28	800,000	2,000	2,222	9,961.86	156.24	10,118.10	10,770.24	-800.00	9,970.24	11,127.55	0.00	11,127.55	11,246.67	0.00	11,246.67	**-147.86**	**-1.5%**	**1,157.31**	**11.6%**	**119.11**	**1.1%**
29	1,000,000	2,000	2,222	9,961.86	156.24	10,118.10	10,770.24	-800.00	9,970.24	11,127.55	0.00	11,127.55	11,246.67	0.00	11,246.67	**-147.86**	**-1.5%**	**1,157.31**	**11.6%**	**119.11**	**1.1%**
30	**Large Use**																				
31	1,500,000	5,000	5,556	22,480.52	389.57	22,870.09	24,939.37	-2,611.11	22,328.25	25,972.34	0.00	25,972.34	26,499.54	0.00	26,499.54	**-541.84**	**-2.4%**	**3,644.09**	**16.3%**	**527.20**	**2.0%**
32	2,000,000	5,000	5,556	22,480.52	389.57	22,870.09	24,939.37	-2,611.11	22,328.25	25,972.34	0.00	25,972.34	26,499.54	0.00	26,499.54	**-541.84**	**-2.4%**	**3,644.09**	**16.3%**	**527.20**	**2.0%**
33	2,500,000	5,000	5,556	22,480.52	389.57	22,870.09	24,939.37	-2,611.11	22,328.25	25,972.34	0.00	25,972.34	26,499.54	0.00	26,499.54	**-541.84**	**-2.4%**	**3,644.09**	**16.3%**	**527.20**	**2.0%**
34	3,000,000	10,000	11,111	42,202.74	778.46	42,981.20	46,994.92	-5,222.22	41,772.70	49,305.68	0.00	49,305.68	50,721.76	0.00	50,721.76	**-1,208.50**	**-2.8%**	**7,532.98**	**18.0%**	**1,416.09**	**2.9%**
35	4,000,000	10,000	11,111	42,202.74	778.46	42,981.20	46,994.92	-5,222.22	41,772.70	49,305.68	0.00	49,305.68	50,721.76	0.00	50,721.76	**-1,208.50**	**-2.8%**	**7,532.98**	**18.0%**	**1,416.09**	**2.9%**
36	5,000,000	10,000	11,111	42,202.74	778.46	42,981.20	46,994.92	-5,222.22	41,772.70	49,305.68	0.00	49,305.68	50,721.76	0.00	50,721.76	**-1,208.50**	**-2.8%**	**7,532.98**	**18.0%**	**1,416.09**	**2.9%**
37	**Street Lighting**	connections	mthly kVA																		
38	9,182,014	159,861	26,461	136,821.66	2,116.84	138,938.50	337,037.64	-7,938.15	329,099.49	428,578.90	0.00	428,578.90	525,676.87	0.00	525,676.87	**190,160.99**	**136.9%**	**99,479.42**	**30.2%**	**97,097.97**	**22.7%**
39	365	1	1	3.86	0.08	3.94	9.41	-0.30	9.11	11.71	0.00	11.71	14.22	0.00	14.22	**5.17**	**131.2%**	**2.60**	**28.5%**	**2.51**	**21.4%**
40	**Unmetered Scattered Loads**		connections																		
41	4,829,242	1,466	17,721	94,982.79	6,760.94	101,743.73	135,264.66	-4,346.32	130,918.35	155,610.41	0.00	155,610.41	174,302.15	0.00	174,302.15	**29,174.62**	**28.7%**	**24,692.07**	**18.9%**	**18,691.74**	**12.0%**
42	365	1	1	8.85	0.51	9.36	12.74	-0.33	12.42	14.68	0.00	14.68	16.37	0.00	16.37	**3.05**	**32.6%**	**2.27**	**18.3%**	**1.69**	**11.5%**

2008 - 2010 Total Bill Impact

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26
					Monthly Bill at 2007 Approved Rates				Monthly Bill at Proposed 2008 Rates				Monthly Bill at Proposed 2009 Rates				Monthly Bill at Proposed 2010 Rates				2008 Increase		2009 Increase		2010 Increase	
1		kWh	kW	kVA	Distribution ($)	Reg Asset Recovery ($)	Non-Distribution ($)	Total ($)	Distribution ($)	Reg Asset Recovery ($)	Non-Distribution ($)	Total ($)	Distribution ($)	Reg Asset Recovery ($)	Non-Distribution ($)	Total ($)	Distribution ($)	Reg Asset Recovery ($)	Non-Distribution ($)	Total ($)	$	%	$	%	$	%
2	**Residential**																									
3		100			13.55	1.00	8.15	22.70	16.58	-0.10	8.15	24.63	18.59	0.00	8.15	26.74	19.91	0.00	8.15	28.06	**1.93**	**8.5%**	**2.11**	**8.6%**	**1.32**	**4.9%**
4		250			15.88	1.48	20.00	37.36	19.18	-0.25	20.00	38.93	21.20	0.00	20.00	41.20	22.57	0.00	20.00	42.57	**1.57**	**4.2%**	**2.28**	**5.8%**	**1.37**	**3.3%**
5		500			19.75	2.28	39.75	61.78	23.50	-0.50	39.75	62.75	25.55	0.00	39.75	65.30	26.99	0.00	39.75	66.74	**0.97**	**1.6%**	**2.55**	**4.1%**	**1.44**	**2.2%**
6		750			23.63	3.08	59.51	86.21	27.83	-0.75	59.51	86.58	29.90	0.00	59.51	89.41	31.42	0.00	59.51	90.92	**0.37**	**0.4%**	**2.83**	**3.3%**	**1.51**	**1.7%**
7		1,000			27.50	3.88	81.40	112.78	32.15	-1.00	81.40	112.55	34.25	0.00	81.40	115.65	35.84	0.00	81.40	117.24	**-0.23**	**-0.2%**	**3.10**	**2.8%**	**1.59**	**1.4%**
8		1,500			35.25	5.48	125.57	166.30	40.80	-1.50	125.57	164.87	42.95	0.00	125.57	168.52	44.69	0.00	125.57	170.26	**-1.43**	**-0.9%**	**3.65**	**2.2%**	**1.74**	**1.0%**
9		2,000			43.00	7.08	169.75	219.83	49.45	-2.00	169.75	217.20	51.65	0.00	169.75	221.40	53.54	0.00	169.75	223.29	**-2.63**	**-1.2%**	**4.20**	**1.9%**	**1.89**	**0.9%**
10	**GS<50 kW**																									
11		1,000			34.57	2.18	81.95	118.70	40.37	-1.00	81.95	121.32	43.24	0.00	81.95	125.19	45.54	0.00	81.95	127.49	**2.62**	**2.2%**	**3.87**	**3.2%**	**2.30**	**1.8%**
12		5,000			108.57	8.18	435.76	552.51	124.37	-5.00	435.76	555.13	130.44	0.00	435.76	566.20	136.34	0.00	435.76	572.10	**2.62**	**0.5%**	**11.07**	**2.0%**	**5.90**	**1.0%**
13		10,000			201.07	15.68	878.02	1,094.77	229.37	-10.00	878.02	1,097.39	239.44	0.00	878.02	1,117.46	249.84	0.00	878.02	1,127.86	**2.62**	**0.2%**	**20.07**	**1.8%**	**10.40**	**0.9%**
14		20,000			386.07	30.68	1,762.53	2,179.28	439.37	-20.00	1,762.53	2,181.90	457.44	0.00	1,762.53	2,219.97	476.84	0.00	1,762.53	2,239.37	**2.62**	**0.1%**	**38.07**	**1.7%**	**19.40**	**0.9%**
15	**GS 50-1000 kW**																									
16		30,000	100	100	523.82	9.68	2,724.43	3,257.93	569.78	-32.00	2,724.43	3,262.21	590.69	0.00	2,724.43	3,315.12	597.01	0.00	2,724.43	3,321.44	**4.28**	**0.1%**	**52.91**	**1.6%**	**6.32**	**0.2%**
17		40,000	100	100	523.82	9.68	3,502.07	4,035.57	569.78	-32.00	3,502.07	4,039.85	590.69	0.00	3,502.07	4,092.76	597.01	0.00	3,502.07	4,099.09	**4.28**	**0.1%**	**52.91**	**1.3%**	**6.32**	**0.2%**
18		150,000	500	556	2,792.49	50.68	13,648.15	16,491.31	3,029.78	-177.78	13,648.15	16,500.15	3,132.69	0.00	13,648.15	16,780.84	3,161.79	0.00	13,648.15	16,809.94	**8.84**	**0.1%**	**280.69**	**1.7%**	**29.10**	**0.2%**
19		200,000	500	556	2,792.49	50.68	17,536.36	20,379.53	3,029.78	-177.78	17,536.36	20,388.37	3,132.69	0.00	17,536.36	20,669.05	3,161.79	0.00	17,536.36	20,698.15	**8.84**	**0.0%**	**280.69**	**1.4%**	**29.10**	**0.1%**
20		270,000	900	1,000	5,005.82	90.68	24,571.87	29,668.37	5,429.78	-320.00	24,571.87	29,681.65	5,612.69	0.00	24,571.87	30,184.56	5,664.01	0.00	24,571.87	30,235.88	**13.28**	**0.0%**	**502.91**	**1.7%**	**51.32**	**0.2%**
21		360,000	900	1,000	5,005.82	90.68	31,570.66	36,667.16	5,429.78	-320.00	31,570.66	36,680.44	5,612.69	0.00	31,570.66	37,183.35	5,664.01	0.00	31,570.66	37,234.67	**13.28**	**0.0%**	**502.91**	**1.4%**	**51.32**	**0.1%**
22		450,000	900	1,000	5,005.82	90.68	38,569.44	43,665.94	5,429.78	-320.00	38,569.44	43,679.22	5,612.69	0.00	38,569.44	44,182.13	5,664.01	0.00	38,569.44	44,233.46	**13.28**	**0.0%**	**502.91**	**1.2%**	**51.32**	**0.1%**
23	**GS 1000-5000 kW**																									
24		300,000	1,000	1,111	5,339.64	78.46	27,492.80	32,910.90	5,748.02	-400.00	27,492.80	32,840.82	5,916.44	0.00	27,492.80	33,409.24	5,968.89	0.00	27,492.80	33,461.68	**-70.08**	**-0.2%**	**568.42**	**1.7%**	**52.45**	**0.2%**
25		400,000	1,000	1,111	5,339.64	78.46	35,269.23	40,687.33	5,748.02	-400.00	35,269.23	40,617.25	5,916.44	0.00	35,269.23	41,185.67	5,968.89	0.00	35,269.23	41,238.12	**-70.08**	**-0.2%**	**568.42**	**1.4%**	**52.45**	**0.1%**
26		500,000	1,000	1,111	5,339.64	78.46	43,045.66	48,463.76	5,748.02	-400.00	43,045.66	48,393.68	5,916.44	0.00	43,045.66	48,962.10	5,968.89	0.00	43,045.66	49,014.55	**-70.08**	**-0.1%**	**568.42**	**1.2%**	**52.45**	**0.1%**
27		600,000	2,000	2,222	9,961.86	156.24	54,992.09	65,110.19	10,770.24	-800.00	54,992.09	64,962.34	11,127.55	0.00	54,992.09	66,119.64	11,246.67	0.00	54,992.09	66,238.76	**-147.86**	**-0.2%**	**1,157.31**	**1.8%**	**119.11**	**0.2%**
28		800,000	2,000	2,222	9,961.86	156.24	70,544.96	80,663.06	10,770.24	-800.00	70,544.96	80,515.20	11,127.55	0.00	70,544.96	81,672.51	11,246.67	0.00	70,544.96	81,791.62	**-147.86**	**-0.2%**	**1,157.31**	**1.4%**	**119.11**	**0.1%**
29		1,000,000	2,000	2,222	9,961.86	156.24	86,097.82	96,215.92	10,770.24	-800.00	86,097.82	96,068.06	11,127.55	0.00	86,097.82	97,225.37	11,246.67	0.00	86,097.82	97,344.49	**-147.86**	**-0.2%**	**1,157.31**	**1.2%**	**119.11**	**0.1%**
30	**Large Use kW**																									
31		1,500,000	5,000	5,556	22,480.52	389.57	136,206.51	159,076.60	24,939.37	-2,611.11	136,206.51	158,534.76	25,972.34	0.00	136,206.51	162,178.85	26,499.54	0.00	136,206.51	162,706.05	**-541.84**	**-0.3%**	**3,644.09**	**2.3%**	**527.20**	**0.3%**
32		2,000,000	5,000	5,556	22,480.52	389.57	174,444.18	197,314.27	24,939.37	-2,611.11	174,444.18	196,772.43	25,972.34	0.00	174,444.18	200,416.52	26,499.54	0.00	174,444.18	200,943.72	**-541.84**	**-0.3%**	**3,644.09**	**1.9%**	**527.20**	**0.3%**
33		2,500,000	5,000	5,556	22,480.52	389.57	212,681.85	235,551.94	24,939.37	-2,611.11	212,681.85	235,010.10	25,972.34	0.00	212,681.85	238,654.19	26,499.54	0.00	212,681.85	239,181.39	**-541.84**	**-0.2%**	**3,644.09**	**1.6%**	**527.20**	**0.2%**
34		3,000,000	10,000	11,111	42,202.74	778.46	272,419.52	315,400.72	46,994.92	-5,222.22	272,419.52	314,192.22	49,305.68	0.00	272,419.52	321,725.20	50,721.76	0.00	272,419.52	323,141.28	**-1,208.50**	**-0.4%**	**7,532.98**	**2.4%**	**1,416.09**	**0.4%**
35		4,000,000	10,000	11,111	42,202.74	778.46	348,894.86	391,876.06	46,994.92	-5,222.22	348,894.86	390,667.56	49,305.68	0.00	348,894.86	398,200.54	50,721.76	0.00	348,894.86	399,616.62	**-1,208.50**	**-0.3%**	**7,532.98**	**1.9%**	**1,416.09**	**0.4%**
36		5,000,000	10,000	11,111	42,202.74	778.46	425,370.20	468,351.40	46,994.92	-5,222.22	425,370.20	467,142.90	49,305.68	0.00	425,370.20	474,675.88	50,721.76	0.00	425,370.20	476,091.96	**-1,208.50**	**-0.3%**	**7,532.98**	**1.6%**	**1,416.09**	**0.3%**
37	**Street Lighting**		connections	mthly kVA																						
38		9,182,014	159,861	26,461	136,821.66	2,116.84	840,507.75	979,446.25	337,037.64	-7,938.15	840,507.75	1,169,607.23	428,578.90	0.00	840,507.75	1,269,086.65	525,676.87	0.00	840,507.75	1,366,184.62	**190,160.99**	**19.4%**	**99,479.42**	**8.5%**	**97,097.97**	**7.7%**
39		365	1	1	3.86	0.08	30.01	33.95	9.41	-0.30	30.01	39.12	11.71	0.00	30.01	41.72	14.22	0.00	30.01	44.23	**5.17**	**15.2%**	**2.60**	**6.6%**	**2.51**	**6.0%**
40	**Unmetered Scattered Loads**		connections																							
41		4,829,242	1,466	17,721	94,982.79	6,760.94	427,147.70	528,891.43	135,264.66	-4,346.32	427,147.70	558,066.05	155,610.41	0.00	427,147.70	582,758.12	174,302.15	0.00	427,147.70	601,449.85	**29,174.62**	**5.5%**	**24,692.07**	**4.4%**	**18,691.74**	**3.2%**
42		365	1	1	8.85	0.51	29.13	38.49	12.74	-0.33	29.13	41.54	14.68	0.00	29.13	43.81	16.37	0.00	29.13	45.50	**3.05**	**7.9%**	**2.27**	**5.5%**	**1.69**	**3.9%**

Calculation of Non-Distribution Charges

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21
				Tot.Loss	**Loss Adj.**		**2007 Rates**					**Commodity**			**Monthly Charges at 2007 Rates**						
												Average								**RPP Admin**	**Total Non-**
1	**kWh**	**kW**	**kVA**	**Factor**	**kWh**	**Connection ($)**	**Network ($)**	**WMS ($)**	**DRC ($)**	**Tier 1 ($)**	**Tier 2 ($)**	**Threshold**	**Tier 1 kWh**	**Tier 2 kWh**	**Connection ($)**	**Network ($)**	**WMS ($)**	**DRC ($)**	**Commodity ($)**	**($)**	**Distribution ($)**
2	**Residential**																				
3	100			1.0376	104	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	104	-	0.47	0.59	0.64	0.70	5.50	0.25	8.15
4	250			1.0376	259	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	259	-	1.17	1.48	1.61	1.75	13.75	0.25	20.00
5	500			1.0376	519	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	519	-	2.33	2.96	3.22	3.50	27.50	0.25	39.75
6	750			1.0376	778	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	778	-	3.50	4.44	4.82	5.25	41.24	0.25	59.51
7	1,000			1.0376	1,038	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	800	238	4.67	5.91	6.43	7.00	57.13	0.25	81.40
8	1,500			1.0376	1,556	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	800	756	7.00	8.87	9.65	10.50	89.30	0.25	125.57
9	2,000			1.0376	2,075	0.0045	0.0057	0.0062	0.0070	0.0530	0.0620	800	800	1,275	9.34	11.83	12.87	14.00	121.46	0.25	169.75
10	**GS<50 kW**																				
11	1,000			1.0376	1,038	0.0045	0.0058	0.0062	0.0070	0.0530	0.0620	750	750	288	4.67	6.02	6.43	7.00	57.58	0.25	81.95
12	5,000			1.0376	5,188	0.0045	0.0058	0.0062	0.0070	0.0530	0.0620	750	750	4,438	23.35	30.09	32.17	35.00	314.91	0.25	435.76
13	10,000			1.0376	10,376	0.0045	0.0058	0.0062	0.0070	0.0530	0.0620	750	750	9,626	46.69	60.18	64.33	70.00	636.56	0.25	878.02
14	20,000			1.0376	20,752	0.0045	0.0058	0.0062	0.0070	0.0530	0.0620	750	750	20,002	93.38	120.36	128.66	140.00	1,279.87	0.25	1,762.53
23	**GS 50-1000 kW**														0.00	0.00					
24	30,000	100	100	1.0376	31,128	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	30,378	171.00	227.00	192.99	210.00	1,923.19	0.25	2,724.43
25	40,000	100	100	1.0376	41,504	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	40,754	171.00	227.00	257.32	280.00	2,566.50	0.25	3,502.07
26	150,000	500	556	1.0376	155,640	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	154,890	855.00	1,135.00	964.97	1,050.00	9,642.93	0.25	13,648.15
27	200,000	500	556	1.0376	207,520	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	206,770	855.00	1,135.00	1,286.62	1,400.00	12,859.49	0.25	17,536.36
28	270,000	900	1,000	1.0376	280,152	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	279,402	1,539.00	2,043.00	1,736.94	1,890.00	17,362.67	0.25	24,571.87
29	360,000	900	1,000	1.0376	373,536	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	372,786	1,539.00	2,043.00	2,315.92	2,520.00	23,152.48	0.25	31,570.66
30	450,000	900	1,000	1.0376	466,920	1.71	2.27	0.0062	0.0070	0.0530	0.0620	750	750	466,170	1,539.00	2,043.00	2,894.90	3,150.00	28,942.29	0.25	38,569.44
31	**GS 1000-5000 kW**																				
32	300,000	1,000	1,111	1.0376	311,280	1.77	2.40	0.0062	0.0070	0.0530	0.0620	750	750	310,530	1,770.00	2,400.00	1,929.94	2,100.00	19,292.61	0.25	27,492.80
33	400,000	1,000	1,111	1.0376	415,040	1.77	2.40	0.0062	0.0070	0.0530	0.0620	750	750	414,290	1,770.00	2,400.00	2,573.25	2,800.00	25,725.73	0.25	35,269.23
34	500,000	1,000	1,111	1.0376	518,800	1.77	2.40	0.0062	0.0070	0.0530	0.0620	750	750	518,050	1,770.00	2,400.00	3,216.56	3,500.00	32,158.85	0.25	43,045.66
35	600,000	2,000	2,222	1.0376	622,560	1.77	2.40	0.0062	0.0070	0.0530	0.0620	750	750	621,810	3,540.00	4,800.00	3,859.87	4,200.00	38,591.97	0.25	54,992.09
36	800,000	2,000	2,222	1.0376	830,080	1.77	2.40	0.0062	0.0070	0.0530	0.0620	750	750	829,330	3,540.00	4,800.00	5,146.50	5,600.00	51,458.21	0.25	70,544.96
37	1,000,000	2,000	2,222	1.0376	1,037,600	1.77	2.40	0.0062	0.0070	0.0530	0.0620	750	750	1,036,850	3,540.00	4,800.00	6,433.12	7,000.00	64,324.45	0.25	86,097.82
38	**Large Use**																				
39	1,500,000	5,000	5,556	1.0187	1,528,050	1.80	2.50	0.0062	0.0070	0.0530	0.0620	750	750	1,527,300	9,000.00	12,500.00	9,473.91	10,500.00	94,732.35	0.25	136,206.51
40	2,000,000	5,000	5,556	1.0187	2,037,400	1.80	2.50	0.0062	0.0070	0.0530	0.0620	750	750	2,036,650	9,000.00	12,500.00	12,631.88	14,000.00	126,312.05	0.25	174,444.18
41	2,500,000	5,000	5,556	1.0187	2,546,750	1.80	2.50	0.0062	0.0070	0.0530	0.0620	750	750	2,546,000	9,000.00	12,500.00	15,789.85	17,500.00	157,891.75	0.25	212,681.85
42	3,000,000	10,000	11,111	1.0187	3,056,100	1.80	2.50	0.0062	0.0070	0.0530	0.0620	750	750	3,055,350	18,000.00	25,000.00	18,947.82	21,000.00	189,471.45	0.25	272,419.52
43	4,000,000	10,000	11,111	1.0187	4,074,800	1.80	2.50	0.0062	0.0070	0.0530	0.0620	750	750	4,074,050	18,000.00	25,000.00	25,263.76	28,000.00	252,630.85	0.25	348,894.86
44	5,000,000	10,000	11,111	1.0187	5,093,500	1.80	2.50	0.0062	0.0070	0.0530	0.0620	750	750	5,092,750	18,000.00	25,000.00	31,579.70	35,000.00	315,790.25	0.25	425,370.20
45	**Street Lighting**	connections	mthly kVA																		
46	9,182,014	159,861	26,461	1.0376	9,527,257	2.03	2.75	0.0062	0.0070	0.0530	0.0620	750	750	9,526,507	53,714.82	72,766.38	59,069.00	64,274.10	590,683.21	0.25	840,507.75
47	365	1	1	1.0376	379	2.03	2.75	0.0062	0.0070	0.0530	0.0620	750	379	-	2.03	2.75	2.35	2.56	20.07	0.25	30.01
48	**Unmetered Scattered Loads**		connections																		
49	4,829,242	1,466	17,721	1.0376	5,010,822	0.0045	0.0058	0.0062	0.0070	0.0530	0.0620	750	750	5,010,072	22,548.70	29,062.77	31,067.09	33,804.70	310,664.20	0.25	427,147.70
50	365	1	1	1.0376	379	0.0045	0.0058	0.0062	0.0070	0.0530	0.0620	750	379	-	1.70	2.20	2.35	2.56	20.07	0.25	29.13

2007 PILS / CORPORATE TAX FILING

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Notes

Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility: Toronto Hydro-Electric System Limited

License Number: ED-2002-0497

File Number: RP-XXXX-XXXX

EB-2007-0680

SUMMARY SHEET

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Ratebase	1,846,774,689	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	58,173,403	4-1 DATA for PILS MODEL	F 23

Calculation of Deemed Interest

Debt Ratio	65.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	5.51%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	66,140,955		

Questions that must be answered — Yes or No

1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? — Yes
   If No, please explain your reasons in the manager's summary.

Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	Yes
2. Does the applicant have any Investment Tax Credits (ITC)?	Yes
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	Yes
4. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes
5. Does the applicant have any Capital Leases?	Yes
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2008 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	Yes
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2008 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2008 and/or prior years?	No
11. Did the applicant make the adjustment for Provincial Capital Tax as required on Page 13 of EDR instructions?	Yes

Tax Rates & Exemptions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Applicant	Rate Base	OCT Exemption
		12,500,000
Toronto Hydro-Electric System Limited	1,846,774,689	12,500,000
Regulated Affiliates (if applicable)		
1.		0
2.		0
3.		0
4.		0
5.		0
Total	1,846,774,689	12,500,000

Corporate Tax Rates for Test Year

Income Range	0 to 300,000	300,000 to 400,000	400,000 to 1,128,519	>1,128,519
Federal	13.12%	22.12%	22.12%	22.12%
Ontario	5.50%	5.50%	5.50%	14.00%
Income Tax Rates used to gross up the true up variance	18.62%	27.62%	27.62%	36.12%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.285%
Surtax	0.00%

2006 Adjusted Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2006 Wires Only
Income before PILs/Taxes	A	121,986,847	0	121,986,847
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	124,560,191	0	124,560,191
Amortization of intangible assets	106		0	0
Recapture of capital cost allowance from Schedule 8	107	0	0	0
Gain on sale of eligible capital property from Schedule 10	108	0	0	0
Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	583,769	0	583,769
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120	142,080	0	142,080
Non-deductible meals and entertainment expense	121	175,001	0	175,001
Non-deductible automobile expenses	122	19,071	0	19,071
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves deducted in prior year	125	0	0	0
Reserves from financial statements- balance at end of year	126	135,670,264	0	135,670,264
Soft costs on construction and renovation of buildings	127	0	0	0

2006 Adjusted Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2006 Wires Only
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0
Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Other Additions				0
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Debt Financing Expenses for Book Purposes	294	455,550	0	455,550
See Attached	295	56,309,788	0	56,309,788
Total Additions		**317,915,714**	**0**	**317,915,714**

2006 Adjusted Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2006 Wires Only
Deductions:				
Gain on disposal of assets per financial statements	401	2,074,548	0	2,074,548
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	122,962,821	0	122,962,821
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	1,146,387	0	1,146,387
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves claimed in current year	413	0	0	0
Reserves from financial statements - balance at beginning of year	414	125,567,928	0	125,567,928
Contributions to deferred income plans	416	0	0	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	0	0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390	0	0	0
Capital Lease Payments	391	48,405	0	48,405
Financing Fees for Tax Under S.20(1)(e)	393	1,121,325	0	1,121,325
See Attached	394	41,004,040	0	41,004,040
Total Deductions		**293,925,454**	**0**	**293,925,454**
Net Income for Tax Purposes		**145,977,107**	**0**	**145,977,107**

2006 Adjusted Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2006 Wires Only
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 4	332	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
TAXABLE INCOME		**145,977,107**	**0**	**145,977,107**

Attachment to 2006 Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Other Additions

	Amount
ARO Accretion Expenses	359,952
Transition cost recovery	10,947,761
Transition cost interest recovery	1,675,008
Smart meter Reg Asset allocated to OPEX	2,610
Smart meter income from rates	2,966,383
Small tools expensed for accounting; capitalized for tax	694,107
Portion of gain re: Belfield recorded in retained earnings	1,476,456
Deferred revenue - 12(1)(a) add back	4,697,526
Dividend income (SunLife shares) not recorded in THESL	15,558
Ontario specified tax credits	174,041
Capital tax per books	5,524,435
Capital Contributions Under S.12(1)x)	27,775,951
	56,309,788

Attachment to 2006 Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Other Deductions

	Amount
ARO Payments - Deductible for Tax	550,832
S.13(7.4) Election	27,775,951
Non-CDM revenue related to Summer Challenge Program	740,318
Smart meter interest/carrying costs not legally entitled to	421,589
Smart meter OPEX recorded as Reg Asset	525,959
Deferred revenue - 20(1)(m) deduction	4,697,526
Ontario capital tax per return	6,022,677
ITC taxed in 2005 but recapture recorded in 2006 income	269,188
	41,004,040

2007 Schedule 8 and 10 UCC and CEC

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Methodology: This schedule starts with 2006 Schedules 8 and 10, as filed in the actual 2006 corporate tax returns; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the 2007 Schedules.

Class	Class Description	UCC End of Year Dec 31/06 per tax returns	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC 2007 Opening Balance
1	Distribution System - post 1987 and pre-Feb. 22, 2005	1,330,505,148	0	0	1,330,505,148
2	Distribution System - pre 1988	477,604,232	0	0	477,604,232
8	General Office/Stores Equip	37,498,082	0	0	37,498,082
10	Computer Hardware/ Vehicles	15,098,964	0	0	15,098,964
10.1	Certain Automobiles	38,556	0	0	38,556
12	Computer Software	8,750,712	0	0	8,750,712
13 1	Lease # 1	1,091,036	0	0	1,091,036
13 2	Lease #2	0	0	0	0
13 3	Lease # 3	0	0	0	0
13 4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	7,201,455	0	0	7,201,455
42	Fibre Optic Cable	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	2,712,645	0	0	2,712,645
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0

47	**Distribution Equipment (acq'd post Feb 22/05)**	209,174,397	0	0	209,174,397
98	**WIP**	67,540,773	0	0	67,540,773
0	0	0	0	0	0
	SUB-TOTAL - UCC	**2,157,216,000**	**0**	**0**	**2,157,216,000**
CEC	**Goodwill**	0	0	0	0
CEC	**Land Rights**	0	0	0	0
CEC	**FMV Bump-up**	0	0	0	0
CEC	**Total**	15,230,568	0	0	15,230,568
0	0	0	0	0	
	SUB-TOTAL - CEC	**15,230,568**	**0**	**0**	**15,230,568**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2007 Projected Capital Transactions		2007 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1908	Buildings and Fixtures	1	5,800,967	1,160,996	5,800,967	1,160,996
2010	Electric Plant Purchased or Sold	1	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0
SUBTOTAL - CLASS 1			**5,800,967**	**1,160,996**	**5,800,967**	**1,160,996**
1620	Buildings and Fixtures	2	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0
1715	Station Equipment	2	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0
1735	Underground Conduit	2	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0
1745	Roads and Trails	2	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0
1840	Underground Conduit	2	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0
1850	Line Transformers	2	0	0	0	0
1855	Services	2	0	0	0	0
1860	Meters	2	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2007 Projected Capital Transactions		2007 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1865	Other Installations on Customer's Premises	2	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	599,257	0	599,257	0
1935	Stores Equipment	8	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	1,042,945	0	1,042,945	0
1945	Measurement and Testing Equipment	8	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0
1955	Communication Equipment	8	2,172,639	0	2,172,639	0
1960	Miscellaneous Equipment	8	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0
1970	Load Management Controls - Customer Premises	8	3,591,306	0	3,591,306	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0
1980	System Supervisory Equipment	8	4,627,914	0	4,627,914	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0
SUBTOTAL - CLASS 8			**12,034,060**	**0**	**12,034,060**	**0**
	Fibre Optic Cable	42	9,173	0	9,173	0
SUBTOTAL - CLASS 42			**9,173**	**0**	**9,173**	**0**
1920	Computer Equipment - Hardware	45	4,935,141	0	4,935,141	0
SUBTOTAL - CLASS 45			**4,935,141**	**0**	**4,935,141**	**0**
1930	Transportation Equipment	10	9,169,615	0	9,169,615	0
SUBTOTAL - CLASS 10			**9,169,615**	**0**	**9,169,615**	**0**
1925	Computer Software - CL12	12	24,100,090	0	24,100,090	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2007 Projected Capital Transactions		2007 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
SUBTOTAL - CLASS 12			**24,100,090**	**0**	**24,100,090**	**0**
1630	Leasehold Improvements	13 1	392,222	0	392,222	0
1710	Leasehold Improvements	13 2	0	0	0	0
1810	Leasehold Improvements	13 3	0	0	0	0
1910	Leasehold Improvements	13 4	0	0	0	0
SUBTOTAL - CLASS 13			**392,222**	**0**	**392,222**	**0**
	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	17		350,099		
SUBTOTAL - CLASS 17			**0**	**350,099**	**0**	**350,099**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0
1675	Generators	43.1	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**	**0**
	Station Equipment	47	0	0	0	0
	Towers and Fixtures	47	0	0	0	0
	Poles and Fixtures	47	0	0	0	0
	Overhead Conductors and Devices	47	8,010,155	0	8,010,155	0
	Underground Conduit	47	0	0	0	0
	Underground Conductors and Devices	47	0	0	0	0
	Transformer Station Equipment - Normally Primary above 50 kV	47	0	0	0	0
	Distribution Station Equipment - Normally Primary below 50 kV	47	11,234,683	0	11,234,683	0
	Storage Battery Equipment	47	0	0	0	0
	Poles, Towers and Fixtures	47	14,734,224	0	14,734,224	0
	Overhead Conductors and Devices	47	0	0	0	0
	Underground Conduit	47	49,591,081	0	49,591,081	0
	Underground Conductors and Devices	47	38,287,391	0	38,287,391	0
	Line Transformers	47	44,244,412	0	44,244,412	0
	Services	47	7,935,137	0	7,935,137	0
	Meters	47	7,603,207	0	7,603,207	0
	Other Installations on Customer's Premises	47	0	0	0	0
	Leased Property on Customer Premises	47	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2007 Projected Capital Transactions		2007 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
	Fixed Assets for Conservation and Demand Management	47	0	0	0	0
	Smart Meters	47	40,799,350	0	40,799,350	0
1995	Contributions and Grants - Credit	47	-33,553,495	0	-33,553,495	0
SUBTOTAL - CLASS 47			**188,886,145**	**0**	**188,886,145**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0	0
1616	Land Rights	ECP	13,605	0	13,605	0
1706	Land Rights	ECP	0	0	0	0
1806	Land Rights	ECP	0	0	0	0
1906	Land Rights	ECP	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0
SUBTOTAL - Eligible Capital Property			**13,605**	**0**	**13,605**	**0**
1615	Land	LAND	6,000,000	1,768,750	6,000,000	1,768,750
1705	Land	LAND	0	0	0	0
1805	Land	LAND	0	0	0	0
1905	Land	LAND	0	0	0	0
SUBTOTAL - Land			**6,000,000**	**1,768,750**	**6,000,000**	**1,768,750**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0
			0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**251,341,018**	**3,279,845**	**251,341,018**	**3,279,845**

2007 Schedule 8 CCA

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC 2007 Opening Balance	2007 Projected Additions	2007 Projected Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2007 CCA	UCC End of 2007
1	Distribution System not in Cl. 47 - post 1987	1,330,505,148	5,800,967	1,160,996	1,335,145,119	2,319,985	1,332,825,133	4%	53,313,005	1,281,832,114
2	Distribution System - pre 1988	477,604,232	0	0	477,604,232	0	477,604,232	6%	28,656,254	448,947,978
8	General Office/Stores Equip	37,498,082	12,034,060	0	49,532,142	6,017,030	43,515,112	20%	8,703,022	40,829,120
10	Computer Hardware/ Vehicles	15,098,964	9,169,615	0	24,268,579	4,584,807	19,683,771	30%	5,905,131	18,363,447
10.1	Certain Automobiles	38,556	0	0	38,556	0	38,556	30%	11,567	26,989
12	Computer Software	8,750,712	24,100,090	0	32,850,802	12,050,045	20,800,757	100%	20,800,757	12,050,045
13 1	Leasehold Improvement # 1	1,091,036	392,222	0	1,483,258	196,111	1,287,147	SL	279,646	1,203,612
13 2	Leasehold Improvement # 2	0	0	0	0	0	0		0	0
13 3	Leasehold Improvement # 3	0	0	0	0	0	0		0	0
13 4	Leasehold Improvement # 4	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	7,201,455	0	350,099	6,851,356	0	6,851,356	8%	548,108	6,303,248
42	Fibre Optic Cable	0	9,173	0	9,173	4,587	4,587	12%	550	8,623
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0

45	**Computers & Systems Software acq'd post Mar 22/04**	2,712,645	4,935,141	0	7,647,786	2,467,570	5,180,215	**45%**	2,331,097	5,316,689
46	**Data Network Infrastructure Equipment (acq'd post Mar 22/04)**	0	0	0	0	0	0	**30%**	0	0
47	**Distribution Equipment (acq'd post Feb 22/05)**	209,174,397	188,886,145	0	398,060,542	94,443,072	303,617,469	**8%**	24,289,398	373,771,144
98	**WIP**	67,540,773	0	0	67,540,773	0	67,540,773		0	67,540,773
0	**0**	0	0	0	0	0	0		0	0
		0	0	0					0	0
		0	0	0					0	0
	TOTAL	**2,157,216,000**	**245,327,413**	**1,511,095**	**2,401,032,318**	**122,083,209**	**2,278,949,110**		**144,838,536**	**2,256,193,782**

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Cumulative Eligible Capital				**15,230,568**
Additions				
Cost of Eligible Capital Property Acquired during 2007	13,605			
Other Adjustments	0			
Subtotal	13,605	**x 3/4 =**	10,204	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			10,204	**10,204**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**15,240,772**
Deductions				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during 2007	0			

Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**

Cumulative Eligible Capital Balance			**15,240,772**
Taxation Year 2007 Deduction	**15,240,772**	**x 7% =**	**1,066,854**
Cumulative Eligible Capital - 2007 Closing Balance			**14,173,918**

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2006	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2006 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2006 Adjusted Utility Balance (C/F Tab "2006 Adjusted Taxable Income)	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2006	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2006 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2006 Adjusted Utility Balance (C/F Tab "2006 Adjusted Taxable Income)	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)	727,887		727,887		727,887	272,113		1,000,000	272,113	
General reserve for bad debts	11,310,387		11,310,387		11,310,387	689,613		12,000,000	689,613	
Accrued Employee Future Benefits:	122,343,778		122,343,778		122,343,778	14,683,222		137,027,000	14,683,222	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost	1,156,604		1,156,604		1,156,604		-1,156,604	0	-1,156,604	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2006	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2006 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2006 Adjusted Utility Balance (C/F Tab "2006 Adjusted Taxable Income)	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**135,538,656**	**0**	**135,538,656**	**0**	**135,538,656**	**15,644,948**	**-1,156,604**	**150,027,000**	**14,488,344**	**0**

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Calculated Deemed 2006 Interest Expense in 2007 EDR model	66,140,955		
2007 Actual Interest Expense	64,537,426	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2007 Capitalized Interest (USoA 6040)		2-2 UNADJUSTED ACCOUNTING DATA	L 431
2007Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 432
2007 Actual Interest	64,537,426		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	64,537,426		
Excess Interest Expense for 2007 PILs	0		

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2006 and prior years.

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income	2006 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		58,173,403	121,986,847	-63,813,444	
Additions:					
Interest and penalties on taxes	103		0	0	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	132,414,733	124,560,191	7,854,542	Capital additions projected for 2007
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		0	0	
Recapture of capital cost allowance from Schedule 8	107		0	0	
Gain on sale of eligible capital property from Schedule 10	108		0	0	
Income or loss for tax purposes- joint ventures or partnerships	109		0	0	
Loss in equity of subsidiaries and affiliates	110		0	0	
Loss on disposal of assets	111		0	0	
Charitable donations	112		0	0	
Taxable Capital Gains	113	4,287,621	583,769	3,703,852	
Political Donations	114		0	0	
Deferred and prepaid expenses	116		0	0	
Scientific research expenditures deducted on financial statements	118		0	0	
Capitalized interest	119		0	0	
Non-deductible club dues and fees	120	0	142,080	-142,080	
Non-deductible meals and entertainment expense	121	0	175,001	-175,001	
Non-deductible automobile expenses	122		19,071	-19,071	
Non-deductible life insurance premiums	123		0	0	
Non-deductible company pension plans	124		0	0	
Tax reserves beginning of year	125	0	0	0	
Reserves from financial statements- balance at end of year	126	150,027,000	135,670,264	14,356,736	
Soft costs on construction and renovation of buildings	127		0	0	
Book loss on joint ventures or partnerships	205		0	0	
Capital items expensed	206		0	0	
Debt issue expense	208		0	0	
Development expenses claimed in current year	212		0	0	
Financing fees deducted in books	216		0	0	
Gain on settlement of debt	220		0	0	
Non-deductible advertising	226		0	0	
Non-deductible interest	227		0	0	
Non-deductible legal and accounting fees	228		0	0	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income	2006 Adjusted Taxable Income	Variance	Explanation for Variance
Recapture of SR&ED expenditures	231		0	0	
Share issue expense	235		0	0	
Write down of capital property	236		0	0	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0	0	
Other Additions: (please explain in detail the nature of the item)					
Interest Expensed on Capital Leases	290	0	0	0	
Realized Income from Deferred Credit Accounts	291		0	0	
Pensions	292		0	0	
Non-deductible penalties	293		0	0	
Debt Financing Expenses for Book Purposes	294	455,550	455,550	0	See Test Year Financing Fees schdeule
See Attached	295	46,376,264	56,309,788	-9,933,524	This is substantially all contributions for capital additions which has an equal deduction below. See " Taxable Income Additions" tab.
	296		0	0	
	297		0	0	
Total Additions		**333,561,168**	**317,915,714**	**15,645,454**	
Deductions:					
Gain on disposal of assets per financial statements	401	11,756,509	2,074,548	9,681,961	
Dividends not taxable under section 83	402		0	0	
Capital cost allowance from Schedule 8	403	144,838,536	122,962,821	21,875,715	capital asset additions projected for 2007
Terminal loss from Schedule 8	404		0	0	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,066,854	1,146,387	-79,533	
Allowable business investment loss	406		0	0	
Deferred and prepaid expenses	409		0	0	
Scientific research expenses claimed in year	411		0	0	
Tax reserves end of year	413	0	0	0	
Reserves from financial statements - balance at beginning of year	414	135,538,656	125,567,928	9,970,728	based on 2007 projected balances
Contributions to deferred income plans	416		0	0	
Book income of joint venture or partnership	305		0	0	
Equity in income from subsidiary or affiliates	306		0	0	
Other deductions: (Please explain in detail the nature of the item)					

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income	2006 Adjusted Taxable Income	Variance	Explanation for Variance
Interest capitalized for accounting deducted for tax	390		0	0	
Capital Lease Payments	391	0	48,405	-48,405	
Financing Fees for Tax Under S.20(1)(e)	393	1,587,075	1,121,325	465,750	
See Attached	394	35,827,957	41,004,040	-5,176,083	This is substantially all contributions for capital additions which has an equal addition above. See "Test Year Taxable Income Deductions" tab.
Excess Interest (from Tab "Schedule 7-3")	395	0	0	0	Applicable to Test Year only
	396		0		
	397		0	0	
Total Deductions		**330,615,588**	**293,925,454**	**36,690,134**	
NET INCOME FOR TAX PURPOSES		**61,118,983**	**145,977,107**	**-84,858,124**	
Charitable donations	311		0	0	
Taxable dividends received under section 112 or 113	320		0	0	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0	
Net-capital loss carried back from 2008	332	867,084	0	867,084	LCB from 2008
Limited partnership losses of preceding taxation years from Schedule 4	335		0	0	
TAXABLE INCOME (C/F to tab "Tax Provision)		**60,251,899**	**145,977,107**	**-85,725,208**	

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Other Additions

	2006 Amount	2007 Amount	Variance
ARO Accretion Expenses	359,952	-	(359,952)
Transition cost recovery	10,947,761	10,947,761	-
Transition cost interest recovery	1,675,008	1,675,008	-
ITC claimed in prior year	-	200,000	200,000
Capital Contributions Under S.12(1)(x)	27,775,951	33,553,495	5,777,544
	40,758,672	46,376,264	5,617,592

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Other Deductions

	2006 Amount	2007 Amount	Variance
ARO Payments - Deductible for Tax	550,832	-	(550,832)
S.13(7.4) Election	27,775,951	33,553,495	5,777,544
AFUDC included in accounting income	-	2,274,462	2,274,462
	28,326,783	35,827,957	7,501,174

Attachment to Test Year Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Financing Fees Continuity

TAX TREATMENT

		Year of	ITA	Amortization									
	Original Cost	Expenditure	Reference	2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002	S. 20(1)(e)	134,250	134,250	134,250	134,250	134,250					-
THC $500M LOC	811,992	2003	S. 20(1)(e)		162,398	162,398	162,398	162,398	162,398				-
THC $500M LOC Setup	243,600	2004	S. 20(1)(e.1)			243,600							-
Debt Issue Costs	2,988,834	2003	S. 20(1)(e)		597,767	597,767	597,767	597,767	597,767				-
LC and Standby Charge	664,551	2003	S. 20(1)(e)		132,910	132,910	132,910	132,910	132,910				-
THC $500M LLC	470,000	2005	S. 20(1)(e)				94,000	94,000	94,000	94,000	94,000		-
$245MM City Note Repayment	3,000,000	2007	S. 20(1)(e)						600,000	600,000	600,000	600,000	600,000
LOC Setup Fee	470,000	2008	S. 20(1)(e)							94,000	94,000	94,000	188,000
$245MM City Note Repayment	3,000,000	2009	S. 20(1)(e)								600,000	600,000	1,800,000
CAPEX Program	2,000,000	2009	S. 20(1)(e)								400,000	400,000	1,200,000
Total			**S. 20(1)(e)**	**134,250**	**1,027,325**	**1,027,325**	**1,121,325**	**1,121,325**	**1,587,075**	**788,000**	**1,788,000**	**1,694,000**	**3,788,000**
Total			**S. 20(1)(e.1)**	**-**	**-**	**243,600**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

ACCOUNTING TREATMENT

		Year of		Amortization									
	Original Cost	Expenditure		2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002		534,688	136,562								-
THC $500M LOC	811,992	2003			541,328	270,664							-
THC $500M LOC Setup	243,600	2004				162,400	81,200						-
Debt Issue Costs	2,988,834	2003			194,435	298,883	298,883	298,883	298,883	298,883	298,883	298,883	702,218
LC and Standby Charge	664,551	2003			664,551								-
THC $500M LLC	470,000	2005					104,444	156,667	156,667	52,222			-
$245MM City Note Repayment	3,000,000	2007								100,000	166,667	166,667	2,566,666
LOC Setup Fee	470,000	2008								104,445	156,667	156,667	52,221
$245MM City Note Repayment	3,000,000	2009										180,000	2,820,000
CAPEX Program	2,000,000	2009										120,000	1,880,000
Total				**534,688**	**1,536,876**	**731,947**	**484,527**	**455,550**	**455,550**	**555,550**	**622,217**	**922,217**	**8,021,105**

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	1,846,774,689
Less: Exemption	12,500,000
Deemed Taxable Capital	1,834,274,689
Rate in 2008	0.285%
Net Amount (Taxable Capital x Rate)	5,227,683

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX

PAID-UP CAPITAL

	From 2007 Trial Balance	Non-Distribution Elimination	Wires Only
Paid-up capital stock	527,816,668		527,816,668
Retained earnings (if deficit, use negative sign)	190,440,071		190,440,071
Capital and other surplus excluding			0
appraisal surplus	12,757,392		12,757,392
Loans and advances	1,198,540,000		1,198,540,000
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits	21,445,000		21,445,000
Contingent, investment, inventory and similar reserves	13,516,930		13,516,930
Other reserves not allowed as deductions	150,027,000		150,027,000
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	2,114,543,061	0	2,114,543,061

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	69,852,471		69,852,471
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	2,044,690,590	0	2,044,690,590

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons	0		0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations	795,000		795,000
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	795,000	0	795,000

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

TOTAL ASSETS

	From 2007 Trial Balance	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	2,313,502,076		2,313,502,076
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	2,313,502,076	0	2,313,502,076
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions	150,027,000		150,027,000
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	69,852,471		69,852,471
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Other adjustments (if deducting, use negative sign)			0
Total Assets	2,393,676,605	0	2,393,676,605
Investment Allowance	679,093	0	679,093
Taxable Capital			
Net paid-up capital	2,044,690,590	0	2,044,690,590
Investment Allowance	679,093	0	679,093
Taxable Capital	2,044,011,497	0	2,044,011,497
Capital Tax Calculation			
Deduction from taxable capital up to $15,000,000	12,500,000		12,500,000
Net Taxable Capital			2,031,511,497
Rate			0.2850%
Ontario Capital Tax (Deductible, not grossed-up)			5,789,808

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Loans and Advances

Advances from Associated Companies	180,000,000
current prtion of LT liabilities	16,600,000
LT Customer deposits	20,740,000
Notes Payable to Associated Companies	980,231,000
Obligations under capital leases - current	458,000
Obligations under capital leases - non current	511,000
Total	1,198,540,000

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Amounts Deducted for Income Tax > of Amounts Booked

Difference @ 12/31/2006 Per Income Tax Return		52,044,726
ADD:	2007 CCA	144,838,536
	2007 CEC Amount	1,066,854
LESS:	2007 Amortization Expense	(132,414,733)
ADD:	2007 AFUDC	2,274,462
ADD:	2007 S. 20(1)(e) amounts	1,587,075
LESS:	2007 Accounting amort. of finance fees	455,550
		69,852,471

Test Year PILs/ Tax Provision

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	Wires Only	2006 Actual	Variance	Explanation of Variance
Regulatory Taxable Income - From 'Test Year Taxable Income'	60,251,899			
Corporate Income Tax Rate	36.12%			
Total Income Taxes	21,762,986			
Investment Tax Credits	200,000	0	200,000	
Miscellaneous Tax Credits			0	
Total Tax Credits	200,000	200,000	0	
Corporate PILs/Income Tax Provision for Test Year	21,562,986			
Ontario Capital Tax	5,789,808			

INCLUSION IN RATES

Income Tax (grossed-up)	33,755,457
Ontario Capital Tax (not grossed-up)	5,789,808
Tax Provision for 2007 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	39,545,265

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	2,601,316	0	2,601,316
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	17,023,030	0	17,023,030
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	79,230,615	0	79,230,615
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	176,082,104	0	176,082,104
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	50,725,985	0	50,725,985
1855	Services	1	0	0	0
1860	Meters	1	13,381,544	0	13,381,544
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**339,044,594**	**0**	**339,044,594**
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	9,166,247	0	9,166,247
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	42,662,639	0	42,662,639
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	95,582,807	0	95,582,807
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	27,313,992	0	27,313,992
1855	Services	2	0	0	0
1860	Meters	2	7,205,447	0	7,205,447
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**181,931,132**	**0**	**181,931,132**
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	24,914	0	24,914
1935	Stores Equipment	8	1,813,980	0	1,813,980
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	2,602,452	0	2,602,452
1960	Miscellaneous Equipment	8	4,228,318	0	4,228,318
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	29,191,326	0	29,191,326
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**37,860,990**	**0**	**37,860,990**
1920	Computer Equipment - Hardware	45	5,731,300	0	5,731,300
SUBTOTAL - CLASS 45			**5,731,300**	**0**	**5,731,300**
1930	Transportation Equipment	10	5,301,287	0	5,301,287
SUBTOTAL - CLASS 10			**5,301,287**	**0**	**5,301,287**
1925	Computer Software - CL12	12	-36,621,766	0	-36,621,766
SUBTOTAL - CLASS 12			**-36,621,766**	**0**	**-36,621,766**
1630	Leasehold Improvements	13 1	-268,210	0	-268,210
1710	Leasehold Improvements	13 2	0	0	0
1810	Leasehold Improvements	13 3	0	0	0
1910	Leasehold Improvements	13 4	0	0	0
SUBTOTAL - CLASS 13			**-268,210**	**0**	**-268,210**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	11,726,704	0	11,726,704
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**11,726,704**	**0**	**11,726,704**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
	Yard Improvements	17	5,854,000	0	5,854,000
	Total FMV Bump-up		**550,560,031**	**0**	**550,560,031**

Fair Market Value (FMV) Bump Supplementry

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Class	Class Description	October 1, 2001 FMV Bump	Rate %	Remaining balance of Bump 2004	Remaining balance of Bump 2006	Remaining balance of Bump 2008
1	Buildings; Electrical generating or distributing equipment and plant (including structures) acquired after 1987	339,044,594	4%	287,966,360	265,389,797	244,583,237
2	Electrical generating or distributing equipment acquired before 1988	181,931,132	6%	142,042,542	125,508,790	110,899,567
8	Office furniture and equipment; Electrical generating equipment acquired after May 25, 1976 that has a max load of not more than 15kws; Portable electrical generating equipment and radio communication equipment acquired after May 25, 1976	37,860,990	20%	15,507,862	9,925,031	6,352,020
10	Automotive equipment & vehicle; Computer hardware - computer hardware and system software	11,032,587	30%	2,648,924	1,297,973	636,007
12	Application software- - subject to half-year rule	(36,621,766)	100%	-	-	-
13	Leasehold Improvements - SL w/ estimated 5 year useful	(268,210)	20%	(53,642)	-	-
17	Yard improvements	5,854,000	8%	4,193,764	3,549,602	3,004,383
CEC	Cumulative Eligible Capital	11,726,704	7%	8,772,184	7,587,062	6,562,050
Total		**550,560,031**		**461,077,994**	**413,258,256**	**372,037,264**

2008 PILS / CORPORATE TAX FILING

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Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility: Toronto Hydro-Electric System Limited

License Number: ED-2002-0497

File Number: RP-XXXX-XXXX

EB-2007-0680

SUMMARY SHEET

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Ratebase	1,978,580,672	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	65,524,885	4-1 DATA for PILS MODEL	F 23
Calculation of Deemed Interest			
Debt Ratio	62.50%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	5.55%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	68,606,130		

Questions that must be answered	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	Yes
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	Yes
2. Does the applicant have any Investment Tax Credits (ITC)?	Yes

3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	Yes
4. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes
5. Does the applicant have any Capital Leases?	Yes
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2008 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	Yes
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2008 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2008 and/or prior years?	No
11. Did the applicant make the adjustment for Provincial Capital Tax as required on Page 13 of EDR instructions?	Yes

Tax Rates & Exemptions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Applicant	Rate Base	OCT Exemption
		15,000,000
Toronto Hydro-Electric System Limited	1,978,580,672	15,000,000
Regulated Affiliates (if applicable)		
1.		0
2.		0
3.		0
4.		0
5.		0
Total	1,978,580,672	15,000,000

Corporate Tax Rates for Test Year

Income Range	0 to 300,000	300,000 to 400,000	400,000 to 1,128,519	>1,128,519
Federal	11.50%	20.50%	20.50%	20.50%
Ontario	5.50%	5.50%	5.50%	14.00%
Income Tax Rates used to gross up the true up variance	17.00%	26.00%	26.00%	34.50%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.285%
Surtax	0.00%

Test Year Schedule 8 and 10 UCC and CEC

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Methodology: This schedule starts with projected 2007 Schedules 8 and 10; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	Projected UCC End of Year Dec 31/07 Per 2007 Sch. 8 & 10	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System not in Cl. 47 - post 1987	1,281,832,114	0	0	1,281,832,114
2	Distribution System - pre 1988	448,947,978	0	0	448,947,978
8	General Office/Stores Equip	40,829,120	0	0	40,829,120
10	Computer Hardware/ Vehicles	18,363,447	0	0	18,363,447
10.1	Certain Automobiles	26,989	0	0	26,989
12	Computer Software	12,050,045	0	0	12,050,045
13 1	Lease # 1	1,203,612	0	0	1,203,612
13 2	Lease #2	0	0	0	0
13 3	Lease # 3	0	0	0	0
13 4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	6,303,248	0	0	6,303,248
42	Fibre Optic Cable	8,623	0	0	8,623
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	5,316,689	0	0	5,316,689
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0

47	**Distribution Equipment (acq'd post Feb 22/05)**	373,771,144	0	0	373,771,144
98	**WIP**	67,540,773	0	0	67,540,773
0	0	0	0	0	0
	SUB-TOTAL - UCC	**2,256,193,782**	**0**	**0**	**2,256,193,782**
CEC	**Goodwill**	0	0	0	0
CEC	**Land Rights**	0	0	0	0
CEC	**FMV Bump-up**	0	0	0	0
CEC	**Total**	14,173,918	0	0	14,173,918
0	0	0	0	0	
	SUB-TOTAL - CEC	**14,173,918**	**0**	**0**	**14,173,918**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2008 Projected Capital Transactions		2008 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1908	Buildings and Fixtures	1	10,370,201	4,692,634	10,370,201	4,692,634
2010	Electric Plant Purchased or Sold	1	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0
SUBTOTAL - CLASS 1			**10,370,201**	**4,692,634**	**10,370,201**	**4,692,634**
1620	Buildings and Fixtures	2	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0
1715	Station Equipment	2	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0
1735	Underground Conduit	2	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0
1745	Roads and Trails	2	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0
1840	Underground Conduit	2	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0
1850	Line Transformers	2	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2008 Projected Capital Transactions		2008 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1855	Services	2	0	0	0	0
1860	Meters	2	0	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	491,700	0	491,700	0
1935	Stores Equipment	8	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	375,000	0	375,000	0
1945	Measurement and Testing Equipment	8	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0
1955	Communication Equipment	8	1,152,038	0	1,152,038	0
1960	Miscellaneous Equipment	8	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0
1970	Load Management Controls - Customer Premises	8	187,560	0	187,560	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0
1980	System Supervisory Equipment	8	2,681,555	0	2,681,555	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0
SUBTOTAL - CLASS 8			**4,887,853**	**0**	**4,887,853**	**0**
	Fibre Optic Cable	42	0	0	0	0
SUBTOTAL - CLASS 42			**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	6,150,077	0	6,150,077	0
SUBTOTAL - CLASS 45			**6,150,077**	**0**	**6,150,077**	**0**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2008 Projected Capital Transactions		2008 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1930	Transportation Equipment	10	8,372,618	40,000	8,372,618	40,000
SUBTOTAL - CLASS 10			**8,372,618**	**40,000**	**8,372,618**	**40,000**
1925	Computer Software - CL12	12	14,908,416	0	14,908,416	0
SUBTOTAL - CLASS 12			**14,908,416**	**0**	**14,908,416**	**0**
1630	Leasehold Improvements	13 [1]	100,000	0	100,000	0
1710	Leasehold Improvements	13 [2]	0	0	0	0
1810	Leasehold Improvements	13 [3]	0	0	0	0
1910	Leasehold Improvements	13 [4]	0	0	0	0
SUBTOTAL - CLASS 13			**100,000**	**0**	**100,000**	**0**
	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	17	0	341,535	0	341,535
SUBTOTAL - CLASS 17			**0**	**341,535**	**0**	**341,535**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0
1675	Generators	43.1	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**	**0**
	Station Equipment	47	0	0	0	0
	Towers and Fixtures	47	0	0	0	0
	Poles and Fixtures	47	0	0	0	0
	Overhead Conductors and Devices	47	8,164,546	0	8,164,546	0
	Underground Conduit	47	0	0	0	0
	Underground Conductors and Devices	47	0	0	0	0
	Transformer Station Equipment - Normally Primary above 50 kV	47	0	0	0	0
	Distribution Station Equipment - Normally Primary below 50 kV	47	19,194,212	0	19,194,212	0
	Storage Battery Equipment	47	0	0	0	0
	Poles, Towers and Fixtures	47	12,096,878	0	12,096,878	0
	Overhead Conductors and Devices	47	0	0	0	0
	Underground Conduit	47	53,076,607	0	53,076,607	0
	Underground Conductors and Devices	47	47,213,558	0	47,213,558	0
	Line Transformers	47	45,985,664	0	45,985,664	0
	Services	47	7,820,863	0	7,820,863	0
	Meters	47	10,295,310	0	10,295,310	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2008 Projected Capital Transactions		2008 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
	Other Installations on Customer's Premises	47	0	0	0	0
	Leased Property on Customer Premises	47	0	0	0	0
	Fixed Assets for Conservation and Demand Management	47	0	0	0	0
	Smart Meters	47	34,078,843	0	34,078,843	0
1995	Contributions and Grants - Credit	47	-27,273,296	0	-27,273,296	0
SUBTOTAL - CLASS 47			**210,653,185**	**0**	**210,653,185**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0
2075	Non-Utility Property Owned or Under Capital	CL	0	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	5,500,000	0	5,500,000	0
1616	Land Rights	ECP	110,000	0	110,000	0
1706	Land Rights	ECP	0	0	0	0
1806	Land Rights	ECP	0	0	0	0
1906	Land Rights	ECP	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0
SUBTOTAL - Eligible Capital Property			**5,610,000**	**0**	**5,610,000**	**0**
1615	Land	LAND	0	3,900,000	0	3,900,000
1705	Land	LAND	0	0	0	0
1805	Land	LAND	0	0	0	0
1905	Land	LAND	0	0	0	0
SUBTOTAL - Land			**0**	**3,900,000**	**0**	**3,900,000**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0
			0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**261,052,351**	**8,974,169**	**261,052,351**	**8,974,169**

Schedule 8 CCA Test Year

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	2008 Projected Additions	2008 Projected Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System not in Cl. 47 - post 1987	1,281,832,114	10,370,201	4,692,634	1,287,509,681	2,838,784	1,284,670,897	4%	51,386,836	1,236,122,845
2	Distribution System - pre 1988	448,947,978	0	0	448,947,978	0	448,947,978	6%	26,936,879	422,011,099
8	General Office/Stores Equip	40,829,120	4,887,853	0	45,716,973	2,443,927	43,273,047	20%	8,654,609	37,062,364
10	Computer Hardware/ Vehicles	18,363,447	8,372,618	40,000	26,696,065	4,166,309	22,529,756	30%	6,758,927	19,937,138
10.1	Certain Automobiles	26,989	0	0	26,989	0	26,989	30%	8,097	18,892
12	Computer Software	12,050,045	14,908,416	0	26,958,461	7,454,208	19,504,253	100%	19,504,253	7,454,208
13 1	Leasehold Improvement # 1	1,203,612	100,000	0	1,303,612	50,000	1,253,612	SL	282,208	1,021,404
13 2	Leasehold Improvement # 2	0	0	0	0	0	0		0	0
13 3	Leasehold Improvement # 3	0	0	0	0	0	0		0	0
13 4	Leasehold Improvement # 4	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	6,303,248	0	341,535	5,961,713	0	5,961,713	8%	476,937	5,484,776
42	Fibre Optic Cable	8,623	0	0	8,623	0	8,623	12%	1,035	7,588
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	5,316,689	6,150,077	0	11,466,766	3,075,039	8,391,728	45%	3,776,277	7,690,489
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0

47	**Distribution Equipment (acq'd post Feb 22/05)**	373,771,144	210,653,185	0	584,424,329	105,326,593	479,097,737	**8%**	38,327,819	546,096,510
98	**WIP**	67,540,773	0	0	67,540,773	0	67,540,773		0	67,540,773
0	**0**	0	0	0	0	0	0		0	0
		0							0	0
		0							0	0
	TOTAL	**2,256,193,782**	**255,442,351**	**5,074,169**	**2,506,561,964**	**125,354,858**	**2,381,207,105**		**156,113,877**	**2,350,448,087**

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

Cumulative Eligible Capital				**14,173,918**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	5,610,000			
Other Adjustments	0			
Subtotal	5,610,000	**x 3/4 =**	4,207,500	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			4,207,500	**4,207,500**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**18,381,418**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			

Subtotal	0	x 3/4 =	0	**0**

Cumulative Eligible Capital Balance			**18,381,418**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")	**18,381,418**	**x 7% =**	**1,286,699**
Cumulative Eligible Capital - Closing Balance			**17,094,718**

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2007	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2007 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2007 Adjusted Utility Balance	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2007	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2007 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2007 Adjusted Utility Balance	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)	1,000,000		1,000,000		1,000,000	0		1,000,000	0	
General reserve for bad debts	12,000,000		12,000,000		12,000,000		-449,000	11,551,000	-449,000	
Accrued Employee Future Benefits:	137,027,000		137,027,000		137,027,000	7,128,000		144,155,000	7,128,000	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost	0		0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2007	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2007 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2007 Adjusted Utility Balance	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**150,027,000**	**0**	**150,027,000**	**0**	**150,027,000**	**7,128,000**	**-449,000**	**156,706,000**	**6,679,000**	**0**

Test Year Net Capital Loss Carry Back

Toronto Hydro Electric System Limited
License Num ED-1999-0193
File Number: RP-XXXX-XXXX, EB-XXXX-XXXX

Property		Cost	Disposal Costs	Proceeds	Gain/Loss	Taxable Capital Gain/(Loss)
Underwriters	Land	3,900,000	240,648	2,406,479	-1,734,169	
	Building	8,450,000	521,404	5,214,038	0	
	Yard	615,000	37,948	379,483	0	
	Total	12,965,000	800,000	8,000,000	-1,734,169	-867,084

Net capital Loss: (867,084) Loss carried back to 2007

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Calculated Deemed Interest Expense in 2008 EDR model	68,606,130		
2008 Actual Interest Expense	63,649,053	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2008 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 431
2008 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 432
2008 Actual Interest	63,649,053		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	63,649,053		
Excess Interest Expense for 2008 PILs	0		

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		65,524,885
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	153,723,682
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	0
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	0
Non-deductible meals and entertainment expense	121	0
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	156,706,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Debt Financing Expenses for Book Purpose	294	555,550
See Attached	295	31,000,988
	296	
	297	
Total Additions		**341,986,220**
Deductions:		
Gain on disposal of assets per financial statements	401	786,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	156,113,877
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,286,699
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	150,027,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Financing Fees for tax under S.20(1)(e)	393	788,000
See Attached	394	30,998,220
Excess Interest (from Tab "Schedule 7-3")	395	0
	396	
	397	
Total Deductions		**339,999,796**
NET INCOME FOR TAX PURPOSES		**67,511,309**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME (C/F to tab "Tax Provision)		**67,511,309**

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Other Additions

ARO Accretion Expenses	372,000
Transition cost recovery	2,736,940
Transition cost iterest recovery	418,752
ITC claimed in prior year	200,000
Capital Contributions Under S.12(1)(x)	27,273,296
	31,000,988

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Other Deductions

ARO Payments - Deductible for Tax	400,000
S.13(7.4) Election	27,273,296
AFUDC included in accounting income	3,324,924
	30,998,220

Attachment to Test Year Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Financing Fees Continuity

TAX TREATMENT

		Year of	ITA	Amortization									
	Original Cost	Expenditure	Reference	2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002	S. 20(1)(e)	134,250	134,250	134,250	134,250	134,250					-
THC $500M LOC	811,992	2003	S. 20(1)(e)		162,398	162,398	162,398	162,398	162,398				-
THC $500M LOC Setup	243,600	2004	S. 20(1)(e.1)			243,600							-
Debt Issue Costs	2,988,834	2003	S. 20(1)(e)		597,767	597,767	597,767	597,767	597,767				-
LC and Standby Charge	664,551	2003	S. 20(1)(e)		132,910	132,910	132,910	132,910	132,910				-
THC $500M LLC	470,000	2005	S. 20(1)(e)				94,000	94,000	94,000	94,000	94,000		-
$245MM City Note Repaym	3,000,000	2007	S. 20(1)(e)						600,000	600,000	600,000	600,000	600,000
LOC Setup Fee	470,000	2008	S. 20(1)(e)							94,000	94,000	94,000	188,000
$245MM City Note Repaym	3,000,000	2009	S. 20(1)(e)								600,000	600,000	1,800,000
CAPEX Program	2,000,000	2009	S. 20(1)(e)								400,000	400,000	1,200,000
Total			**S. 20(1)(e)**	**134,250**	**1,027,325**	**1,027,325**	**1,121,325**	**1,121,325**	**1,587,075**	**788,000**	**1,788,000**	**1,694,000**	**3,788,000**
Total			**S. 20(1)(e.1)**	**-**	**-**	**243,600**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

ACCOUNTING TREATMENT

		Year of		Amortization									
	Original Cost	Expenditure		2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002		534,688	136,562								-
THC $500M LOC	811,992	2003			541,328	270,664							-
THC $500M LOC Setup	243,600	2004				162,400	81,200						-
Debt Issue Costs	2,988,834	2003			194,435	298,883	298,883	298,883	298,883	298,883	298,883	298,883	702,218
LC and Standby Charge	664,551	2003			664,551								-
THC $500M LLC	470,000	2005					104,444	156,667	156,667	52,222			-
$245MM City Note Repaym	3,000,000	2007								100,000	166,667	166,667	2,566,666
LOC Setup Fee	470,000	2008								104,445	156,667	156,667	52,221
$245MM City Note Repaym	3,000,000	2009										180,000	2,820,000
CAPEX Program	2,000,000	2009										120,000	1,880,000
Total				**534,688**	**1,536,876**	**731,947**	**484,527**	**455,550**	**455,550**	**555,550**	**622,217**	**922,217**	**8,021,105**

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	1,978,580,672
Less: Exemption	15,000,000
Deemed Taxable Capital	1,963,580,672
Rate in 2008	0.285%
Net Amount (Taxable Capital x Rate)	5,596,205

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX

PAID-UP CAPITAL

	From 2008 Trial Balance	Non-Distribution Elimination	Wires Only
Paid-up capital stock	527,817,000		527,817,000
Retained earnings (if deficit, use negative sign)	240,369,948		240,369,948
Capital and other surplus excluding			0
appraisal surplus	12,757,392		12,757,392
Loans and advances	1,201,488,000		1,201,488,000
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits	10,020,000		10,020,000
Contingent, investment, inventory and similar reserves	15,473,113		15,473,113
Other reserves not allowed as deductions	156,706,000		156,706,000
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	2,164,631,453	0	2,164,631,453

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	648,452,469		648,452,469
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	1,516,178,984	0	1,516,178,984

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations	346,000		346,000
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	346,000	0	346,000

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

TOTAL ASSETS

	From 2008 Trial Balance	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	2,370,557,453		2,370,557,453
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	2,370,557,453	0	2,370,557,453
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions	156,706,000		156,706,000
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	648,452,469		648,452,469
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Other adjustments (if deducting, use negative sign)			0
Total Assets	1,878,810,984	0	1,878,810,984
Investment Allowance	279,218	0	279,218
Taxable Capital			
Net paid-up capital	1,516,178,984	0	1,516,178,984
Investment Allowance	279,218	0	279,218
Taxable Capital	1,515,899,766	0	1,515,899,766
Capital Tax Calculation			
Deduction from taxable capital up to $15,000,000	15,000,000		15,000,000
Net Taxable Capital			1,500,899,766
Rate			0.2850%
Ontario Capital Tax (Deductible, not grossed-up)			4,277,564

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Loans and Advances

Advances from Associated Companies	180,000,000
current prtion of LT liabilities	20,585,000
LT Customer deposits	20,023,000
Notes Payable to Associated Companies	980,231,000
Obligations under capital leases - current	451,000
Obligations under capital leases - non current	198,000
Total	1,201,488,000

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Amounts Deducted for Income Tax > of Amounts Booked

Difference @ 12/31/2006 Per Income Tax Return		52,044,726
ADD:	2007 CCA	144,838,536
	2007 CEC Amount	1,066,854
LESS:	2007 Amortization Expense	132,414,733
ADD:	2007 AFUDC	2,274,462
ADD:	2008 CCA	156,113,877
	2008 CEC Amount	1,286,699
LESS:	2008 Amortization Expense	153,723,682
ADD:	2008 AFUDC	3,324,924
ADD:	2007 S. 20(1)(e) amounts	1,587,075
	2008 S. 20(1)(e) amounts	788,000
LESS:	2007 Accounting amort. of finance fees	(455,550)
	2008 Accounting amort. of finance fees	(555,550)
		648,452,469

Test Year PILs/ Tax Provision

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	Wires Only			
Regulatory Taxable Income - From 'Test Year Taxable Income'	67,511,309			
Corporate Income Tax Rate	34.50%			
Total Income Taxes	23,291,402	2006 Actual	Variance	Explanation of Variance
Investment Tax Credits	200,000	0	200,000	
Miscellaneous Tax Credits			0	
Total Tax Credits	200,000	200,000	0	
Corporate PILs/Income Tax Provision for Test Year	23,091,402			
Ontario Capital Tax	5,596,205			

INCLUSION IN RATES

Income Tax (grossed-up)	35,254,048
Ontario Capital Tax (not grossed-up)	5,596,205
Tax Provision for 2008 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	40,850,253

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	2,601,316	0	2,601,316
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	17,023,030	0	17,023,030
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	79,230,615	0	79,230,615
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	176,082,104	0	176,082,104
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	50,725,985	0	50,725,985
1855	Services	1	0	0	0
1860	Meters	1	13,381,544	0	13,381,544
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**339,044,594**	**0**	**339,044,594**
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	9,166,247	0	9,166,247
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	42,662,639	0	42,662,639
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	95,582,807	0	95,582,807
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	27,313,992	0	27,313,992
1855	Services	2	0	0	0
1860	Meters	2	7,205,447	0	7,205,447
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**181,931,132**	**0**	**181,931,132**
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	24,914	0	24,914
1935	Stores Equipment	8	1,813,980	0	1,813,980
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	2,602,452	0	2,602,452
1960	Miscellaneous Equipment	8	4,228,318	0	4,228,318
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	29,191,326	0	29,191,326
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**37,860,990**	**0**	**37,860,990**
1920	Computer Equipment - Hardware	45	5,731,300	0	5,731,300
SUBTOTAL - CLASS 45			**5,731,300**	**0**	**5,731,300**
1930	Transportation Equipment	10	5,301,287	0	5,301,287
SUBTOTAL - CLASS 10			**5,301,287**	**0**	**5,301,287**
1925	Computer Software - CL12	12	-36,621,766	0	-36,621,766
SUBTOTAL - CLASS 12			**-36,621,766**	**0**	**-36,621,766**
1630	Leasehold Improvements	13 1	-268,210	0	-268,210
1710	Leasehold Improvements	13 2	0	0	0
1810	Leasehold Improvements	13 3	0	0	0
1910	Leasehold Improvements	13 4	0	0	0
SUBTOTAL - CLASS 13			**-268,210**	**0**	**-268,210**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	11,726,704	0	11,726,704
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**11,726,704**	**0**	**11,726,704**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
	Yard Improvements	17	5,854,000	0	5,854,000
	Total FMV Bump-up		**550,560,031**	**0**	**550,560,031**

Fair Market Value (FMV) Bump Supplementry

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Class	Class Description	October 1, 2001 FMV Bump	Rate %	Remaining balance of Bump 2008
1	Buildings; Electrical generating or distributing equipment and plant (including structures) acquired after 1987	339,044,594	4%	244,583,237
2	Electrical generating or distributing equipment acquired before 1988	181,931,132	6%	110,899,567
8	Office furniture and equipment; Electrical generating equipment acquired after May 25, 1976 that has a max load of not more than 15kws; Portable electrical generating equipment and radio communication equipment acquired after May 25, 1976	37,860,990	20%	6,352,020
10	Automotive equipment & vehicle; Computer hardware - computer hardware and system software	11,032,587	30%	636,007
12	Application software- - subject to half-year rule	(36,621,766)	100%	-
13	Leasehold Improvements - SL w/ estimated 5 year useful	(268,210)	20%	-
17	Yard improvements	5,854,000	8%	3,004,383
CEC	Cumulative Eligible Capital	11,726,704	7%	6,562,050
Total		**550,560,031**		**372,037,264**

2009 PILS / CORPORATE TAX FILING

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Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility: Toronto Hydro-Electric System Limited

License Number: ED-2002-0497

File Number: RP-XXXX-XXXX

EB-2007-0680

SUMMARY SHEET

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Ratebase	2,138,295,619	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	77,458,389	4-1 DATA for PILS MODEL	F 23
Calculation of Deemed Interest			
Debt Ratio	60.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	5.57%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	71,473,594		

Questions that must be answered	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	Yes
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	Yes
2. Does the applicant have any Investment Tax Credits (ITC)?	Yes
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	Yes

4. Does the applicant have any Capital Gains or Losses for tax purposes?	No
5. Does the applicant have any Capital Leases?	Yes
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2009 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	Yes
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2009 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2009 and/or prior years?	No
11. Did the applicant make the adjustment for Provincial Capital Tax as required on Page 13 of EDR instructions?	Yes

Tax Rates & Exemptions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Applicant	Rate Base	OCT Exemption
		15,000,000
Toronto Hydro-Electric System Limited	2,138,295,619	15,000,000
Regulated Affiliates (if applicable)		
1.		0
2.		0
3.		0
4.		0
5.		0
Total	2,138,295,619	15,000,000

Corporate Tax Rates for Test Year

Income Range	0 to 300,000	300,000 to 400,000	400,000 to 1,128,519	>1,128,519
Federal	11.00%	20.00%	20.00%	20.00%
Ontario	5.50%	14.00%	14.00%	14.00%
Income Tax Rates used to gross up the true up variance	16.50%	34.00%	34.00%	34.00%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.225%
Surtax	0.00%

Test Year Schedule 8 and 10 UCC and CEC

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Methodology: This schedule starts with projected 2008 Schedules 8 and 10; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	Projected UCC End of Year Dec 31/08 Per 2008 Sch. 8 & 10	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System not in Cl. 47 - post 1987 and pre Feb. 23 2005	1,236,122,845	0	0	1,236,122,845
2	Distribution System - pre 1988	422,011,099	0	0	422,011,099
8	General Office/Stores Equip	37,062,364	0	0	37,062,364
10	Computer Hardware/ Vehicles	19,937,138	0	0	19,937,138
10.1	Certain Automobiles	18,892	0	0	18,892
12	Computer Software	7,454,208	0	0	7,454,208
13 1	Lease # 1	1,021,404	0	0	1,021,404
13 2	Lease #2	0	0	0	0
13 3	Lease # 3	0	0	0	0
13 4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	5,484,776	0	0	5,484,776
42	Fibre Optic Cable	7,588	0	0	7,588
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	7,690,489	0	0	7,690,489
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
47	Distribution Equipment (acq'd post Feb 22/05)	546,096,510	0	0	546,096,510
98	WIP	67,540,773	0	0	67,540,773
0	0	0	0	0	0

	SUB-TOTAL - UCC	**2,350,448,087**	**0**	**0**	**2,350,448,087**
CEC	**Goodwill**	0	0	0	0
CEC	**Land Rights**	0	0	0	0
CEC	**FMV Bump-up**	0	0	0	0
CEC	**Total**	17,094,718	0	0	17,094,718
0	0	0	0	0	0
	SUB-TOTAL - CEC	**17,094,718**	**0**	**0**	**17,094,718**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2009 Projected Capital Transactions		2009 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1908	Buildings and Fixtures	1	6,929,842	0	6,929,842	0
2010	Electric Plant Purchased or Sold	1	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0
SUBTOTAL - CLASS 1			**6,929,842**	**0**	**6,929,842**	**0**
1620	Buildings and Fixtures	2	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0
1715	Station Equipment	2	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0
1735	Underground Conduit	2	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0
1745	Roads and Trails	2	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0
1840	Underground Conduit	2	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0
1850	Line Transformers	2	0	0	0	0
1855	Services	2	0	0	0	0
1860	Meters	2	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2009 Projected Capital Transactions		2009 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1865	Other Installations on Customer's Premises	2	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	50,000	0	50,000	0
1935	Stores Equipment	8	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	425,000	0	425,000	0
1945	Measurement and Testing Equipment	8	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0
1955	Communication Equipment	8	904,385	0	904,385	0
1960	Miscellaneous Equipment	8	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0
1980	System Supervisory Equipment	8	1,764,993	0	1,764,993	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0
SUBTOTAL - CLASS 8			**3,144,378**	**0**	**3,144,378**	**0**
	Fibre Optic Cable	42	0	0	0	0
SUBTOTAL - CLASS 42			**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	5,091,093	0	5,091,093	0
SUBTOTAL - CLASS 45			**5,091,093**	**0**	**5,091,093**	**0**
1930	Transportation Equipment	10	8,064,750	40,000	8,064,750	40,000
SUBTOTAL - CLASS 10			**8,064,750**	**40,000**	**8,064,750**	**40,000**
1925	Computer Software - CL12	12	33,506,730	0	33,506,730	0
SUBTOTAL - CLASS 12			**33,506,730**	**0**	**33,506,730**	**0**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2009 Projected Capital Transactions		2009 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1630	Leasehold Improvements	13 [1]	100,000	0	100,000	0
1710	Leasehold Improvements	13 [2]	0	0	0	0
1810	Leasehold Improvements	13 [3]	0	0	0	0
1910	Leasehold Improvements	13 [4]	0	0	0	0
SUBTOTAL - CLASS 13			**100,000**	**0**	**100,000**	**0**
	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	17	0	0	0	0
SUBTOTAL - CLASS 17			**0**	**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0
1675	Generators	43.1	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**	**0**
	Station Equipment	47	0	0	0	0
	Towers and Fixtures	47	0	0	0	0
	Poles and Fixtures	47	0	0	0	0
	Overhead Conductors and Devices	47	8,246,619	0	8,246,619	0
	Underground Conduit	47	0	0	0	0
	Underground Conductors and Devices	47	0	0	0	0
	Transformer Station Equipment - Normally Primary above 50 kV	47	0	0	0	0
	Distribution Station Equipment - Normally Primary below 50 kV	47	17,284,691	0	17,284,691	0
	Storage Battery Equipment	47	0	0	0	0
	Poles, Towers and Fixtures	47	12,494,906	0	12,494,906	0
	Overhead Conductors and Devices	47	0	0	0	0
	Underground Conduit	47	58,660,228	0	58,660,228	0
	Underground Conductors and Devices	47	52,146,880	0	52,146,880	0
	Line Transformers	47	40,997,862	0	40,997,862	0
	Services	47	8,208,635	0	8,208,635	0
	Meters	47	11,823,645	0	11,823,645	0
	Other Installations on Customer's Premises	47	0	0	0	0
	Leased Property on Customer Premises	47	0	0	0	0
	Fixed Assets for Conservation and Demand Management	47	0	0	0	0
	Smart Meters	47	37,900,129	0	37,900,129	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2009 Projected Capital Transactions		2009 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1995	Contributions and Grants - Credit	47	-19,600,000	0	-19,600,000	0
SUBTOTAL - CLASS 47			**228,163,594**	**0**	**228,163,594**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0
2075	Non-Utility Property Owned or Under Capital	CL	0	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	10,500,000	0	10,500,000	0
1616	Land Rights	ECP	0	0	0	0
1706	Land Rights	ECP	0	0	0	0
1806	Land Rights	ECP	0	0	0	0
1906	Land Rights	ECP	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0
SUBTOTAL - Eligible Capital Property			**10,500,000**	**0**	**10,500,000**	**0**
1615	Land	LAND	0	0	0	0
1705	Land	LAND	0	0	0	0
1805	Land	LAND	0	0	0	0
1905	Land	LAND	0	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0
			0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**295,500,386**	**40,000**	**295,500,386**	**40,000**

Schedule 8 CCA Test Year

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	2009 Projected Additions	2009 Projected Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System not in Cl. 47 - post 1987 and pre Feb. 23 2005	1,236,122,845	6,929,842	0	1,243,052,687	3,464,921	1,239,587,766	4%	49,583,511	1,193,469,176
2	Distribution System - pre 1988	422,011,099	0	0	422,011,099	0	422,011,099	6%	25,320,666	396,690,433
8	General Office/Stores Equip	37,062,364	3,144,378	0	40,206,742	1,572,189	38,634,553	20%	7,726,911	32,479,831
10	Computer Hardware/ Vehicles	19,937,138	8,064,750	40,000	27,961,888	4,012,375	23,949,513	30%	7,184,854	20,777,034
10.1	Certain Automobiles	18,892	0	0	18,892	0	18,892	30%	5,668	13,225
12	Computer Software	7,454,208	33,506,730	0	40,960,938	16,753,365	24,207,573	100%	24,207,573	16,753,365
13 1	Leasehold Improvement # 1	1,021,404	100,000	0	1,121,404	50,000	1,071,404	SL	294,013	827,391
13 2	Leasehold Improvement # 2	0	0	0	0	0	0		0	0
13 3	Leasehold Improvement # 3	0	0	0	0	0	0		0	0
13 4	Leasehold Improvement # 4	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	5,484,776	0	0	5,484,776	0	5,484,776	8%	438,782	5,045,993
42	Fibre Optic Cable	7,588	0	0	7,588	0	7,588	12%	911	6,678
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	7,690,489	5,091,093	0	12,781,582	2,545,546	10,236,035	45%	4,606,216	8,175,366
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
47	Distribution Equipment (acq'd post Feb 22/05)	546,096,510	228,163,594	0	774,260,104	114,081,797	660,178,307	8%	52,814,265	721,445,840
98	WIP	67,540,773	0	0	67,540,773	0	67,540,773		0	67,540,773
0	0	0	0	0	0	0	0		0	0
		0							0	0
		0							0	0
	TOTAL	2,350,448,087	285,000,386	40,000	2,635,408,473	142,480,193	2,492,928,280		172,183,368	2,463,225,105

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Cumulative Eligible Capital				**17,094,718**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	10,500,000			
Other Adjustments	0			
Subtotal	10,500,000	**x 3/4 =**	7,875,000	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			7,875,000	**7,875,000**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**24,969,718**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**

Cumulative Eligible Capital Balance			**24,969,718**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")	**24,969,718**	**x 7% =**	**1,747,880**
Cumulative Eligible Capital - Closing Balance			**23,221,838**

Schedule 13 – Tax Reserves

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2008	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2008 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2008 Adjusted Utility Balance	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	green		0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2008	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2008 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2008 Adjusted Utility Balance	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)	1,000,000		1,000,000		1,000,000			1,000,000	0	
General reserve for bad debts	11,551,000		11,551,000		11,551,000	23,000		11,574,000	23,000	
Accrued Employee Future Benefits:	145,155,000		145,155,000		145,155,000	8,302,000		153,457,000	8,302,000	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost	0		0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	

Schedule 13 – Tax Reserves

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2008	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2008 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2008 Adjusted Utility Balance	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
			0		0			0	0	
			0		0			0	0	
Total	**157,706,000**	**0**	**157,706,000**	**0**	**157,706,000**	**8,325,000**	**0**	**166,031,000**	**8,325,000**	**0**

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Calculated Deemed Interest Expense in 2009 EDR model	71,473,594		
2009 Actual Interest Expense	65,821,002	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2009 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 431
2009 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 432
2009 Actual Interest	65,821,002		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	65,821,002		
Excess Interest Expense for 2009 PILs	0		

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		77,458,389
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	160,886,305
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	0
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	0
Non-deductible meals and entertainment expense	121	0
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	166,031,000
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Debt Financing Expenses for Book Purposes	294	622,217
See Attached	295	20,193,000
	296	
	297	
Total Additions		**347,732,522**
Deductions:		
Gain on disposal of assets per financial statements	401	40,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	172,183,368
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,747,880
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	157,706,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Financing Fees for tax under S.20(1)(e)	393	1,788,000
See Attached	394	23,793,566
Excess Interest (from Tab "Schedule 7-3")	395	0
	396	
	397	
Total Deductions		**357,258,814**
NET INCOME FOR TAX PURPOSES		**67,932,097**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME (C/F to tab "Tax Provision)		**67,932,097**

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX , EB-2007-0680

Other Additions

ARO Accretion Expenses	393,000
ITC claimed in prior year	200,000
Capital Contributions Under S.12(1)x)	19,600,000
	20,193,000

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX , EB-2007-0680

Other Deductions

ARO Payments - Deductible for Tax	280,000
S.13(7.4) Election	19,600,000
AFUDC included in accounting income	3,913,566
	23,793,566

Attachment to Test Year Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX , EB-2007-0680

Financing Fees Continuity

TAX TREATMENT

	Original Cost	Year of Expenditure	ITA Reference	Amortization 2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002	S. 20(1)(e)	134,250	134,250	134,250	134,250	134,250					-
THC $500M LOC	811,992	2003	S. 20(1)(e)		162,398	162,398	162,398	162,398	162,398				-
THC $500M LOC Setup	243,600	2004	S. 20(1)(e.1)			243,600							-
Debt Issue Costs	2,988,834	2003	S. 20(1)(e)		597,767	597,767	597,767	597,767	597,767				-
LC and Standby Charge	664,551	2003	S. 20(1)(e)		132,910	132,910	132,910	132,910	132,910				-
THC $500M LLC	470,000	2005	S. 20(1)(e)				94,000	94,000	94,000	94,000	94,000		-
$245MM City Note Repaym	3,000,000	2007	S. 20(1)(e)						600,000	600,000	600,000	600,000	600,000
LOC Setup Fee	470,000	2008	S. 20(1)(e)							94,000	94,000	94,000	188,000
$245MM City Note Repaym	3,000,000	2009	S. 20(1)(e)								600,000	600,000	1,800,000
CAPEX Program	2,000,000	2009	S. 20(1)(e)								400,000	400,000	1,200,000
Total			**S. 20(1)(e)**	**134,250**	**1,027,325**	**1,027,325**	**1,121,325**	**1,121,325**	**1,587,075**	**788,000**	**1,788,000**	**1,694,000**	**3,788,000**
Total			**S. 20(1)(e.1)**	**-**	**-**	**243,600**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

ACCOUNTING TREATMENT

	Original Cost	Year of Expenditure		Amortization 2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002		534,688	136,562								-
THC $500M LOC	811,992	2003			541,328	270,664							-
THC $500M LOC Setup	243,600	2004				162,400	81,200						-
Debt Issue Costs	2,988,834	2003			194,435	298,883	298,883	298,883	298,883	298,883	298,883	298,883	702,218
LC and Standby Charge	664,551	2003			664,551								-
THC $500M LLC	470,000	2005					104,444	156,667	156,667	52,222			-
$245MM City Note Repaym	3,000,000	2007								100,000	166,667	166,667	2,566,666
LOC Setup Fee	470,000	2008								104,445	156,667	156,667	52,221
$245MM City Note Repaym	3,000,000	2009										180,000	2,820,000
CAPEX Program	2,000,000	2009										120,000	1,880,000
Total				**534,688**	**1,536,876**	**731,947**	**484,527**	**455,550**	**455,550**	**555,550**	**622,217**	**922,217**	**8,021,105**

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	2,138,295,619
Less: Exemption	15,000,000
Deemed Taxable Capital	2,123,295,619
Rate in 2009	0.225%
Net Amount (Taxable Capital x Rate)	4,777,415

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX

PAID-UP CAPITAL

	From 2009 Projected Trial Balance	Non-Distribution Elimination	Wires Only
Paid-up capital stock	527,817,000		527,817,000
Retained earnings (if deficit, use negative sign)	304,644,160		304,644,160
Capital and other surplus excluding			0
appraisal surplus	12,757,392		12,757,392
Loans and advances	1,276,072,000		1,276,072,000
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits	16,014,000		16,014,000
Contingent, investment, inventory and similar reserves	6,665,405		6,665,405
Other reserves not allowed as deductions	166,031,000		166,031,000
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	2,310,000,957	0	2,310,000,957
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	988,349,371		988,349,371
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	1,321,651,586	0	1,321,651,586

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations	346,000		346,000
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	346,000	0	346,000

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

TOTAL ASSETS

	From 2009 Projected Trial Balance	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	2,519,675,957		2,519,675,957
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	2,519,675,957	0	2,519,675,957
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions	166,031,000		166,031,000
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	988,349,371		988,349,371
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0
Other adjustments (if deducting, use negative sign)			0
Total Assets	1,697,357,586	0	1,697,357,586

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Investment Allowance	269,414	0	269,414
Taxable Capital			
Net paid-up capital	1,321,651,586	0	1,321,651,586
Investment Allowance	269,414	0	269,414
Taxable Capital	1,321,382,172	0	1,321,382,172
Capital Tax Calculation			
Deduction from taxable capital up to $15,000,000	15,000,000		15,000,000
Net Taxable Capital			1,306,382,172
Rate			0.2250%
Ontario Capital Tax (Deductible, not grossed-up)			2,939,360

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Loans and Advances

Advances from Associated Companies	180,000,000
current prtion of LT liabilities	20,585,000
LT Customer deposits	20,031,000
Notes Payable to Associated Companies	1,055,231,000
Obligations under capital leases - current	109,000
Obligations under capital leases - non current	116,000
Total	1,276,072,000

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Amounts Deducted for Income Tax > of Amounts Booked

Difference @ 12/31/2006 Per Income Tax Return		52,044,726
ADD:	2007 CCA	144,838,536
	2007 CEC Amount	1,066,854
LESS:	2007 Amortization Expense	132,414,733
ADD:	2007 AFUDC	2,274,462
ADD:	2008 CCA	156,113,877
	2008 CEC Amount	1,286,699
LESS:	2008 Amortization Expense	153,723,682
ADD:	2008 AFUDC	3,324,924
ADD:	2009 CCA	172,183,368
	2009 CEC Amount	1,747,880
LESS:	2009 Amortization Expense	160,886,305
ADD:	2009 AFUDC	3,913,566
ADD:	2007 S. 20(1)(e) amounts	1,587,075
	2008 S. 20(1)(e) amounts	788,000
	2009 S. 20(1)(e) amounts	1,788,000
LESS:	2007 Accounting amort. of finance fees	(455,550)
	2008 Accounting amort. of finance fees	(555,550)
	2009 Accounting amort. of finance fees	(622,217)
		988,349,371

Test Year PILs/ Tax Provision

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	Wires Only			
Regulatory Taxable Income - From 'Test Year Taxable Income'	67,932,097			
Corporate Income Tax Rate	34.00%			
Total Income Taxes	23,096,913	2006 Actual	Variance	Explanation of Variance
Investment Tax Credits	200,000		200,000	
Miscellaneous Tax Credits			0	
Total Tax Credits	200,000	0	200,000	
Corporate PILs/Income Tax Provision for Test Year	22,896,913			
Ontario Capital Tax	4,777,415			

INCLUSION IN RATES

Income Tax (grossed-up)	34,692,292
Ontario Capital Tax (not grossed-up)	4,777,415
Tax Provision for 2009 EDR Model Rate Recovery **(EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)**	39,469,707

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	2,601,316	0	2,601,316
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	17,023,030	0	17,023,030
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	79,230,615	0	79,230,615
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	176,082,104	0	176,082,104
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	50,725,985	0	50,725,985
1855	Services	1	0	0	0
1860	Meters	1	13,381,544	0	13,381,544
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**339,044,594**	**0**	**339,044,594**

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	9,166,247	0	9,166,247
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	42,662,639	0	42,662,639
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	95,582,807	0	95,582,807
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	27,313,992	0	27,313,992
1855	Services	2	0	0	0
1860	Meters	2	7,205,447	0	7,205,447
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**181,931,132**	**0**	**181,931,132**

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	24,914	0	24,914
1935	Stores Equipment	8	1,813,980	0	1,813,980
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	2,602,452	0	2,602,452
1960	Miscellaneous Equipment	8	4,228,318	0	4,228,318
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	29,191,326	0	29,191,326
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**37,860,990**	**0**	**37,860,990**
1920	Computer Equipment - Hardware	45	5,731,300	0	5,731,300
SUBTOTAL - CLASS 45			**5,731,300**	**0**	**5,731,300**
1930	Transportation Equipment	10	5,301,287	0	5,301,287
SUBTOTAL - CLASS 10			**5,301,287**	**0**	**5,301,287**
1925	Computer Software - CL12	12	-36,621,766	0	-36,621,766
SUBTOTAL - CLASS 12			**-36,621,766**	**0**	**-36,621,766**
1630	Leasehold Improvements	13 1	-268,210	0	-268,210
1710	Leasehold Improvements	13 2	0	0	0
1810	Leasehold Improvements	13 3	0	0	0
1910	Leasehold Improvements	13 4	0	0	0
SUBTOTAL - CLASS 13			**-268,210**	**0**	**-268,210**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	11,726,704	0	11,726,704

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**11,726,704**	**0**	**11,726,704**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
	Yard Improvements	17	5,854,000	0	5,854,000
	Total FMV Bump-up		**550,560,031**	**0**	**550,560,031**

Fair Market Value (FMV) Bump Supplementry

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Class	Class Description	October 1, 2001 FMV Bump	Rate %	Remaining balance of Bump 2004	Remaining balance of Bump 2006	CCA of Bump 2007	Remaining balance of Bump 2007	CCA of Bump 2008	Remaining balance of Bump 2008	CCA of Bump 2009	Remaining balance of Bump 2009
1	Buildings; Electrical generating or distributing equipment and plant (including structures) acquired after 1987	339,044,594	4%	287,966,360	265,389,797	10,615,592	254,774,205	10,190,968	244,583,237	9,783,329	234,799,908
2	Electrical generating or distributing equipment acquired before 1988	181,931,132	6%	142,042,542	125,508,790	7,530,527	117,978,263	7,078,696	110,899,567	6,653,974	104,245,593
8	Office furniture and equipment; Electrical generating equipment acquired after May 25, 1976 that has a max load of not more than 15kws; Portable electrical generating equipment and radio communication equipment acquired after May 25, 1976	37,860,990	20%	15,507,862	9,925,031	1,985,006	7,940,025	1,588,005	6,352,020	1,270,404	5,081,616
10	Automotive equipment & vehicle; Computer hardware - computer hardware and system software	11,032,587	30%	2,648,924	1,297,973	389,392	908,581	272,574	636,007	190,802	445,205
12	Application software- - subject to half-year rule	(36,621,766)	100%	-	-	0	0	0	0	0	0
13	Leasehold Improvements - SL w/ estimated 5 year	(268,210)	20%	(53,642)	-	0	0	0	0	0	0
17	Yard improvements	5,854,000	8%	4,193,764	3,549,602	283,968	3,265,634	261,251	3,004,383	240,351	2,764,033
CEC	Cumulative Eligible Capital	11,726,704	7%	8,772,184	7,587,062	531,094	7,055,968	493,918	6,562,050	459,344	6,102,707
Total		**550,560,031**		**461,077,994**	**413,258,256**	**21,335,580**	**391,922,676**	**19,885,412**	**372,037,264**	**18,598,204**	**353,439,061**

2010 PILS / CORPORATE TAX FILING

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Notes

Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility: Toronto Hydro-Electric System Limited

License Number: ED-2002-0497

File Number: RP-XXXX-XXXX

EB-2007-0680

SUMMARY SHEET

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Ratebase	2,269,889,940	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	83,475,411	4-1 DATA for PILS MODEL	F 23
Calculation of Deemed Interest			
Debt Ratio	60.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	5.64%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	76,863,997		

Questions that must be answered	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	Yes
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ?	Yes

If No, please explain your reasons in the manager's summary.

2. Does the applicant have any Investment Tax Credits (ITC)?	Yes
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	Yes
4. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes
5. Does the applicant have any Capital Leases?	Yes
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2010 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	Yes
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2010 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2010 and/or prior years?	No
11. Did the applicant make the adjustment for Provincial Capital Tax as required on Page 13 of EDR instructions?	Yes

Tax Rates & Exemptions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Applicant	Rate Base	OCT Exemption
		15,000,000
Toronto Hydro-Electric System Limited	2,269,889,940	15,000,000
Regulated Affiliates (if applicable)		
1.		0
2.		0
3.		0
4.		0
5.		0
Total	2,269,889,940	15,000,000

Corporate Tax Rates for Test Year

Income Range	0 to 300,000	300,000 to 400,000	400,000 to 1,128,519	>1,128,519
Federal	11.00%	19.00%	19.00%	19.00%
Ontario	5.50%	14.00%	14.00%	14.00%
Income Tax Rates used to gross up the true up variance	16.50%	33.00%	33.00%	33.00%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.150%
Surtax	0.00%

Test Year Schedule 8 and 10 UCC and CEC

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Methodology: This schedule starts with projected 2009 Schedules 8 and 10; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	Projected UCC End of Year Dec 31/09 Per 2009 Sch. 8 & 10	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System not in Cl. 47 - post 1987 and pre Feb. 23 2005	1,193,469,176	0	0	1,193,469,176
2	Distribution System - pre 1988	396,690,433	0	0	396,690,433
8	General Office/Stores Equip	32,479,831	0	0	32,479,831
10	Computer Hardware/ Vehicles	20,777,034	0	0	20,777,034
10.1	Certain Automobiles	13,225	0	0	13,225
12	Computer Software	16,753,365	0	0	16,753,365
13 1	Lease # 1	827,391	0	0	827,391
13 2	Lease #2	0	0	0	0
13 3	Lease # 3	0	0	0	0
13 4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	5,045,993	0	0	5,045,993
42	Fibre Optic Cable	6,678	0	0	6,678
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	8,175,366	0	0	8,175,366
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0

47	**Distribution Equipment (acq'd post Feb 22/05)**	721,445,840	0	0	721,445,840
98	**WIP**	67,540,773	0	0	67,540,773
0	0	0	0	0	0
	SUB-TOTAL - UCC	**2,463,225,105**	**0**	**0**	**2,463,225,105**
CEC	**Goodwill**	0	0	0	0
CEC	**Land Rights**	0	0	0	0
CEC	**FMV Bump-up**	0	0	0	0
CEC	**Total**	23,221,838	0	0	23,221,838
0	0	0	0	0	0
	SUB-TOTAL - CEC	**23,221,838**	**0**	**0**	**23,221,838**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2010 Projected Capital Transactions		2010 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1908	Buildings and Fixtures	1	11,210,929	1,105,000	11,210,929	1,105,000
2010	Electric Plant Purchased or Sold	1	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0
SUBTOTAL - CLASS 1			**11,210,929**	**1,105,000**	**11,210,929**	**1,105,000**
1620	Buildings and Fixtures	2	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0
1715	Station Equipment	2	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0
1735	Underground Conduit	2	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0
1745	Roads and Trails	2	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0
1840	Underground Conduit	2	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0
1850	Line Transformers	2	0	0	0	0
1855	Services	2	0	0	0	0
1860	Meters	2	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2010 Projected Capital Transactions		2010 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1865	Other Installations on Customer's Premises	2	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	1,800,000	0	1,800,000	0
1935	Stores Equipment	8	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	475,000	0	475,000	0
1945	Measurement and Testing Equipment	8	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0
1955	Communication Equipment	8	712,585	0	712,585	0
1960	Miscellaneous Equipment	8	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0
1980	System Supervisory Equipment	8	1,713,548	0	1,713,548	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0
SUBTOTAL - CLASS 8			**4,701,133**	**0**	**4,701,133**	**0**
	Fibre Optic Cable	42	0	0	0	0
SUBTOTAL - CLASS 42			**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	5,913,943	0	5,913,943	0
SUBTOTAL - CLASS 45			**5,913,943**	**0**	**5,913,943**	**0**
1930	Transportation Equipment	10	7,860,950	40,000	7,860,950	40,000
SUBTOTAL - CLASS 10			**7,860,950**	**40,000**	**7,860,950**	**40,000**
1925	Computer Software - CL12	12	19,544,308	0	19,544,308	0
SUBTOTAL - CLASS 12			**19,544,308**	**0**	**19,544,308**	**0**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2010 Projected Capital Transactions		2010 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1630	Leasehold Improvements	13 1	100,000	0	100,000	0
1710	Leasehold Improvements	13 2	0	0	0	0
1810	Leasehold Improvements	13 3	0	0	0	0
1910	Leasehold Improvements	13 4	0	0	0	0
SUBTOTAL - CLASS 13			**100,000**	**0**	**100,000**	**0**
	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	**17**	0	20,000	0	20,000
SUBTOTAL - Class 17			**0**	**20,000**	**0**	**20,000**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0
1675	Generators	43.1	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**	**0**
	Station Equipment	47	0	0	0	0
	Towers and Fixtures	47	0	0	0	0
	Poles and Fixtures	47	0	0	0	0
	Overhead Conductors and Devices	47	8,578,530	0	8,578,530	0
	Underground Conduit	47	65,091,087	0	65,091,087	0
	Underground Conductors and Devices	47	54,072,986	0	54,072,986	0
	Transformer Station Equipment - Normally Primary above 50 kV	47	0	0	0	0
	Distribution Station Equipment - Normally Primary below 50 kV	47	17,271,770	0	17,271,770	0
	Storage Battery Equipment	47	0	0	0	0
	Poles, Towers and Fixtures	47	13,442,536	0	13,442,536	0
	Overhead Conductors and Devices	47	0	0	0	0
	Underground Conduit	47	0	0	0	0
	Underground Conductors and Devices	47	0	0	0	0
	Line Transformers	47	44,002,238	0	44,002,238	0
	Services	47	8,606,919	0	8,606,919	0
	Meters	47	7,430,852	0	7,430,852	0
	Other Installations on Customer's Premises	47	0	0	0	0
	Leased Property on Customer Premises	47	0	0	0	0
	Fixed Assets for Conservation and Demand Management	47	0	0	0	0
	Smart Meters	47	24,733,570	0	24,733,570	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Total Capital Assets for PILs Model		CCA Class	2010 Projected Capital Transactions		2010 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1995	Contributions and Grants - Credit	47	-19,600,000	0	-19,600,000	0
SUBTOTAL - CLASS 47			**223,630,487**	**0**	**223,630,487**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0
2075	Non-Utility Property Owned or Under Capital	CL	0	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	21,000,000	0	21,000,000	0
1616	Land Rights	ECP	0	0	0	0
1706	Land Rights	ECP	0	0	0	0
1806	Land Rights	ECP	0	0	0	0
1906	Land Rights	ECP	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0
SUBTOTAL - Eligible Capital Property			**21,000,000**	**0**	**21,000,000**	**0**
1615	Land	LAND	0	575,000	0	575,000
1705	Land	LAND	0	0	0	0
1805	Land	LAND	0	0	0	0
1905	Land	LAND	0	0	0	0
SUBTOTAL - Land			**0**	**575,000**	**0**	**575,000**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0
			0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**293,961,749**	**1,740,000**	**293,961,749**	**1,740,000**

Schedule 8 CCA Test Year

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	2010 Projected Additions	2010 Projected Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System not in Cl. 47 - post 1987 and pre Feb. 23 2005	1,193,469,176	11,210,929	1,105,000	1,203,575,105	5,052,964	1,198,522,141	4%	47,940,886	1,155,634,220
2	Distribution System - pre 1988	396,690,433	0	0	396,690,433	0	396,690,433	6%	23,801,426	372,889,007
8	General Office/Stores Equip	32,479,831	4,701,133	0	37,180,964	2,350,566	34,830,397	20%	6,966,079	30,214,884
10	Computer Hardware/ Vehicles	20,777,034	7,860,950	40,000	28,597,984	3,910,475	24,687,509	30%	7,406,253	21,191,732
10.1	Certain Automobiles	13,225	0	0	13,225	0	13,225	30%	3,967	9,257
12	Computer Software	16,753,365	19,544,308	0	36,297,672	9,772,154	26,525,519	100%	26,525,519	9,772,154
13 1	Leasehold Improvement # 1	827,391	100,000	0	927,391	50,000	877,391	SL	307,406	619,985
13 2	Leasehold Improvement # 2	0	0	0	0	0	0		0	0
13 3	Leasehold Improvement # 3	0	0	0	0	0	0		0	0
13 4	Leasehold Improvement # 4	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	5,045,993	0	20,000	5,025,993	0	5,025,993	8%	402,079	4,623,914
42	Fibre Optic Cable	6,678	0	0	6,678	0	6,678	12%	801	5,876
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	8,175,366	5,913,943	0	14,089,309	2,956,971	11,132,337	45%	5,009,552	9,079,757
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0

47	**Distribution Equipment (acq'd post Feb 22/05)**	721,445,840	223,630,487	0	945,076,327	111,815,243	833,261,083	**8%**	66,660,887	878,415,440
98	**WIP**	67,540,773	0	0	67,540,773	0	67,540,773		0	67,540,773
0	**0**	0	0	0	0	0	0		0	0
		0							0	0
		0							0	0
	TOTAL	**2,463,225,105**	**272,961,749**	**1,165,000**	**2,735,021,854**	**135,908,374**	**2,599,113,480**		**185,024,855**	**2,549,996,999**

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX , EB-2007-0680

Cumulative Eligible Capital				**23,221,838**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	21,000,000			
Other Adjustments	0			
Subtotal	21,000,000	**x 3/4 =**	15,750,000	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			15,750,000	**15,750,000**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**38,971,838**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			

Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**

Cumulative Eligible Capital Balance			**38,971,838**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")	**38,971,838**	**x 7% =**	**2,728,029**
Cumulative Eligible Capital - Closing Balance			**36,243,810**

Schedule 13 – Tax Reserves

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX , EB-2007-0680

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2009	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2009 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2009 Adjusted Utility Balance (C/F Tab "2006 Adjusted Taxable Income)	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX , EB-2007-0680

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2009	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2009 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2009 Adjusted Utility Balance (C/F Tab "2006 Adjusted Taxable Income)	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)	1,000,000		1,000,000		1,000,000			1,000,000	0	
General reserve for bad debts	11,574,000		11,574,000		11,574,000	23,000		11,597,000	23,000	
Accrued Employee Future Benefits:	153,457,000		153,457,000		153,457,000	8,521,000		161,978,000	8,521,000	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost	0		0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	

Schedule 13 – Tax Reserves

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX , EB-2007-0680

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2009	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2009 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2009 Adjusted Utility Balance (C/F Tab "2006 Adjusted Taxable Income)	Test Year Adjustments: Add (+)	Test Year Adjustments: Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**166,031,000**	**0**	**166,031,000**	**0**	**166,031,000**	**8,544,000**	**0**	**174,575,000**	**8,544,000**	**0**

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Calculated Deemed 2006 Interest Expense in 2010 EDR model	76,863,997		
2010 Actual Interest Expense	69,924,484	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2010 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 431
2010 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 432
2010 Actual Interest	69,924,484		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	69,924,484		
Excess Interest Expense for 2010 PILs	0		

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2006 and prior years.

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		83,475,411
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	174,420,111
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	1,400,000
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	0
Non-deductible meals and entertainment expense	121	0
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	174,575,000
Soft costs on construction and renovation of buildings	127	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
Debt Financing Expenses for Book Purpose	294	922,217
See Attached	295	20,127,000
	296	
	297	
Total Additions		**371,444,328**

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
Deductions:		
Gain on disposal of assets per financial statements	401	3,939,536
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	185,024,855
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	2,728,029
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	166,031,000
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Financing Fees for Tax Under S.20(1)(e)	393	1,694,000
See Attached	394	24,407,417
Excess Interest (from Tab "Schedule 7-3")	395	0
	396	
	397	
Total Deductions		**383,824,837**

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	T2 S1 line #	Test Year Taxable Income
NET INCOME FOR TAX PURPOSES		**71,094,902**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME (C/F to tab "Tax Provision)		**71,094,902**

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX , EB-2007-0680

Other Additions

ARO Accretion Expenses	327,000
ITC claimed in prior year	200,000
Capital Contributions Under S.12(1)x)	19,600,000
	20,127,000

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX , EB-2007-0680

Other Deductions

ARO Payments - Deductible for Tax	205,000
S.13(7.4) Election	19,600,000
AFUDC included in accounting income	4,602,417
	24,407,417

Attachment to Test Year Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX , EB-2007-0680

Financing Fees Continuity

TAX TREATMENT

				Amortization									
	Original Cost	Year of Expenditure	ITA Reference	2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002	S. 20(1)(e)	134,250	134,250	134,250	134,250	134,250					-
THC $500M LOC	811,992	2003	S. 20(1)(e)		162,398	162,398	162,398	162,398	162,398				-
THC $500M LOC Setup	243,600	2004	S. 20(1)(e.1)			243,600							-
Debt Issue Costs	2,988,834	2003	S. 20(1)(e)		597,767	597,767	597,767	597,767	597,767				-
LC and Standby Charge	664,551	2003	S. 20(1)(e)		132,910	132,910	132,910	132,910	132,910				-
THC $500M LLC	470,000	2005	S. 20(1)(e)				94,000	94,000	94,000	94,000	94,000		-
$245MM City Note Repaym	3,000,000	2007	S. 20(1)(e)						600,000	600,000	600,000	600,000	600,000
LOC Setup Fee	470,000	2008	S. 20(1)(e)							94,000	94,000	94,000	188,000
$245MM City Note Repaym	3,000,000	2009	S. 20(1)(e)								600,000	600,000	1,800,000
CAPEX Program	2,000,000	2009	S. 20(1)(e)								400,000	400,000	1,200,000
Total			**S. 20(1)(e)**	**134,250**	**1,027,325**	**1,027,325**	**1,121,325**	**1,121,325**	**1,587,075**	**788,000**	**1,788,000**	**1,694,000**	**3,788,000**
Total			**S. 20(1)(e.1)**	**-**	**-**	**243,600**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

ACCOUNTING TREATMENT

				Amortization									
	Original Cost	Year of Expenditure		2002	2003	2004	2005	2006	2007	2008	2009	2010	Ending NBV
2002 LOC	671,250	2002		534,688	136,562								-
THC $500M LOC	811,992	2003			541,328	270,664							-
THC $500M LOC Setup	243,600	2004				162,400	81,200						-
Debt Issue Costs	2,988,834	2003			194,435	298,883	298,883	298,883	298,883	298,883	298,883	298,883	702,218
LC and Standby Charge	664,551	2003			664,551								-
THC $500M LLC	470,000	2005					104,444	156,667	156,667	52,222			-
$245MM City Note Repaym	3,000,000	2007								100,000	166,667	166,667	2,566,666
LOC Setup Fee	470,000	2008								104,445	156,667	156,667	52,221
$245MM City Note Repaym	3,000,000	2009										180,000	2,820,000
CAPEX Program	2,000,000	2009										120,000	1,880,000
Total				**534,688**	**1,536,876**	**731,947**	**484,527**	**455,550**	**455,550**	**555,550**	**622,217**	**922,217**	**8,021,105**

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	2,269,889,940
Less: Exemption	15,000,000
Deemed Taxable Capital	2,254,889,940
Rate in 2010	0.150%
Net Amount (Taxable Capital x Rate)	3,382,335

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX

PAID-UP CAPITAL

	From 2006 Tax Return	Non-Distribution Elimination	Wires Only
Paid-up capital stock	527,817,000		527,817,000
Retained earnings (if deficit, use negative sign)	376,335,555		376,335,555
Capital and other surplus excluding			0
appraisal surplus	12,757,392		12,757,392
Loans and advances	1,330,857,000		1,330,857,000
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits	22,339,000		22,339,000
Contingent, investment, inventory and similar reserves	6,761,247		6,761,247
Other reserves not allowed as deductions	174,575,000		174,575,000
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	2,451,442,194	0	2,451,442,194

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	1,355,896,566		1,355,896,566
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	1,095,545,628	0	1,095,545,628

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations	346,000		346,000
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	346,000	0	346,000

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

TOTAL ASSETS

	From 2006 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	2,661,945,194		2,661,945,194
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	2,661,945,194	0	2,661,945,194
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions	174,575,000		174,575,000
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	1,355,896,566		1,355,896,566
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0

Ontario Capital Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

Other adjustments (if deducting, use negative sign)			0
Total Assets	1,480,623,628	0	1,480,623,628
Investment Allowance	256,013	0	256,013
Taxable Capital			
Net paid-up capital	1,095,545,628	0	1,095,545,628
Investment Allowance	256,013	0	256,013
Taxable Capital	1,095,289,615	0	1,095,289,615
Capital Tax Calculation			
Deduction from taxable capital up to $15,000,000	15,000,000		15,000,000
Net Taxable Capital			1,080,289,615
Rate			0.1500%
Ontario Capital Tax (Deductible, not grossed-up)			1,620,434

Attachment to Test Year OCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Loans and Advances

Advances from Associated Companies	180,000,000
current prtion of LT liabilities	20,585,000
LT Customer deposits	20,031,000
Notes Payable to Associated Companies	1,110,231,000
Obligations under capital leases - current	10,000
Total	1,330,857,000

Attachment to Test Year

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Amounts Deducted for Income Tax > of Amounts Booked

Difference @ 12/31/2006 Per Income Tax Return		52,044,726
ADD:	2007 CCA	144,838,536
	2007 CEC Amount	1,066,854
LESS:	2007 Amortization Expense	132,414,733
ADD:	2007 AFUDC	2,274,462
ADD:	2008 CCA	156,113,877
	2008 CEC Amount	1,286,699
LESS:	2008 Amortization Expense	153,723,682
ADD:	2008 AFUDC	3,324,924
ADD:	2009 CCA	172,183,368
	2009 CEC Amount	1,747,880
LESS:	2009 Amortization Expense	160,886,305
ADD:	2009 AFUDC	3,913,566
ADD:	2010 CCA	185,024,855
	2010 CEC Amount	2,728,029
LESS:	2010 Amortization Expense	174,420,111
ADD:	2010 AFUDC	4,602,417
ADD:	2007 S. 20(1)(e) amounts	1,587,075
	2008 S. 20(1)(e) amounts	788,000
	2009 S. 20(1)(e) amounts	1,788,000
	2010 S. 20(1)(e) amounts	1,694,000
LESS:	2007 Accounting amort. of finance fees	(455,550)
	2008 Accounting amort. of finance fees	(555,550)
	2009 Accounting amort. of finance fees	(622,217)
	2010 Accounting amort. of finance fees	(922,217)
		1,355,896,566

Test Year PILs/ Tax Provision

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

	Wires Only			
Regulatory Taxable Income - From 'Test Year Taxable Income'	71,094,902			
Corporate Income Tax Rate	33.00%			
Total Income Taxes	23,461,318	2006 Actual	Variance	Explanation of Variance
Investment Tax Credits	200,000	0	200,000	
Miscellaneous Tax Credits			0	
Total Tax Credits	200,000	200,000	0	
Corporate PILs/Income Tax Provision for Test Year	23,261,318			
Ontario Capital Tax	3,382,335			

INCLUSION IN RATES

Income Tax (grossed-up)	34,718,385
Ontario Capital Tax (not grossed-up)	3,382,335
Tax Provision for 2010 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	38,100,719

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	2,601,316	0	2,601,316
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	17,023,030	0	17,023,030
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	79,230,615	0	79,230,615
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	176,082,104	0	176,082,104
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	50,725,985	0	50,725,985
1855	Services	1	0	0	0
1860	Meters	1	13,381,544	0	13,381,544
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**339,044,594**	**0**	**339,044,594**
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	9,166,247	0	9,166,247
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	42,662,639	0	42,662,639
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	95,582,807	0	95,582,807
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	27,313,992	0	27,313,992
1855	Services	2	0	0	0
1860	Meters	2	7,205,447	0	7,205,447
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**181,931,132**	**0**	**181,931,132**
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	24,914	0	24,914
1935	Stores Equipment	8	1,813,980	0	1,813,980
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	2,602,452	0	2,602,452
1960	Miscellaneous Equipment	8	4,228,318	0	4,228,318
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	29,191,326	0	29,191,326
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**37,860,990**	**0**	**37,860,990**
1920	Computer Equipment - Hardware	45	5,731,300	0	5,731,300
SUBTOTAL - CLASS 45			**5,731,300**	**0**	**5,731,300**
1930	Transportation Equipment	10	5,301,287	0	5,301,287
SUBTOTAL - CLASS 10			**5,301,287**	**0**	**5,301,287**
1925	Computer Software - CL12	12	-36,621,766	0	-36,621,766
SUBTOTAL - CLASS 12			**-36,621,766**	**0**	**-36,621,766**
1630	Leasehold Improvements	13 1	-268,210	0	-268,210
1710	Leasehold Improvements	13 2	0	0	0
1810	Leasehold Improvements	13 3	0	0	0
1910	Leasehold Improvements	13 4	0	0	0
SUBTOTAL - CLASS 13			**-268,210**	**0**	**-268,210**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2007-0680

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	11,726,704	0	11,726,704
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**11,726,704**	**0**	**11,726,704**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
	Yard Improvements	17	5,854,000	0	5,854,000
	Total FMV Bump-up		**550,560,031**	**0**	**550,560,031**

Fair Market Value (FMV) Bump Supplementry

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2007-0680

Class	Class Description	October 1, 2001 FMV Bump	Rate %	Remaining balance of Bump 2004	Remaining balance of Bump 2006	CCA of Bump 2007	Remaining balance of Bump 2007	CCA of Bump 2008	Remaining balance of Bump 2008	CCA of Bump 2009	Remaining balance of Bump 2009	CCA of Bump 2010	Remaining balance of Bump 2010
1	Buildings; Electrical generating or distributing equipment and plant (including structures) acquired after 1987	339,044,594	4%	287,966,360	265,389,797	10,615,592	254,774,205	10,190,968	244,583,237	9,783,329	234,799,908	9,391,996	225,407,911
2	Electrical generating or distributing equipment acquired before 1988	181,931,132	6%	142,042,542	125,508,790	7,530,527	117,978,263	7,078,696	110,899,567	6,653,974	104,245,593	6,254,736	97,990,857
8	Office furniture and equipment; Electrical generating equipment acquired after May 25, 1976 that has a max load of not more than 15kws; Portable electrical generating equipment and radio communication equipment acquired after May 25, 1976	37,860,990	20%	15,507,862	9,925,031	1,985,006	7,940,025	1,588,005	6,352,020	1,270,404	5,081,616	1,016,323	4,065,293
10	Automotive equipment & vehicle; Computer hardware - computer hardware and system software	11,032,587	30%	2,648,924	1,297,973	389,392	908,581	272,574	636,007	190,802	445,205	133,561	311,643
12	Application software- - subject to half-year rule	(36,621,766)	100%	-	-	0	0	0	0	0	0	0	0
13	Leasehold Improvements - SL w/ estimated 5 year	(268,210)	20%	(53,642)	-	0	0	0	0	0	0	0	0
17	Yard improvements	5,854,000	8%	4,193,764	3,549,602	283,968	3,265,634	261,251	3,004,383	240,351	2,764,033	221,123	2,542,910
CEC	Cumulative Eligible Capital	11,726,704	7%	8,772,184	7,587,062	531,094	7,055,968	493,918	6,562,050	459,344	6,102,707	427,189	5,675,517
Total		**550,560,031**		**461,077,994**	**413,258,256**	**21,335,580**	**391,922,676**	**19,885,412**	**372,037,264**	**18,598,204**	**353,439,061**	**17,444,929**	**335,994,132**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

Version 10

ADJ 3 (DISTRIBUTION EXPENSES -TIER 1)

Tier 1 Adjustments related to ***Distribution Expenses*** *(Sheet 1 of 3).*

			posted to account
5) Low Voltage/Wheeling Adjustments	**(Handbook p.13)**		
(Embedded Distributors only)			
Amount included in 2004 Trial Balance data, if any			
Incremental Amount per section A (Handbook, p. 13)			
Amount per section C (Handboook, p. 13)	255,430		
[above items to Sheet 5-5 B.R.R. #2]			
Adjustment		**255,430**	5665 - Miscellaneous General Expenses

1-2 ADJUSTED ACCOUNTING DATA

GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)

	2008 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2008 Accounts as Adjusted for 2008 Rate Calculation	
	$	$	$	$	$	
Land and Buildings	67,731,017	67,731,017	0	0	65,637,261	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	7,542,507	7,542,507	0	0	4,792,507	1815
DS	179,487,101	179,487,101	0	0	169,889,995	1820
Poles, Wires	2,328,854,397	2,328,854,397	0	0	2,267,582,846	1830, 1835, 1840, 1845
Line Transformers	637,012,017	637,012,017	0	0	613,639,344	1850
Services and Meters	307,375,831	307,375,831	0	0	243,794,874	1855, 1860
General Plant	102,927,167	102,927,167	0	0	104,553,612	1908, 1910
Equipment	163,174,175	163,174,175	0	0	157,978,497	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	197,063,927	197,063,927	0	0	186,534,680	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	0	1565 (new account)
Other Distribution Assets	64,417,127	64,417,127	0	0	62,982,570	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-233,735,937	-233,735,937	0	0	-219,874,258	1995
Accumulated Amortization	-2,020,430,992	-2,020,430,992	0	0	-1,945,306,351	2105, 2120
Non-Distribution Asset	-0	-0	0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	698,000	698,000	0	0	698,000	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 1515, 1516, 1518, 1520, 1525, 1530, 1540, 1545, 1548, 1560, 1562, 1563, 1570, 1571, 1572, 1574, 1580, 1582, 1584, 1586, 1588, 1605, 2060, 2140
Liability	-0	-0	0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 2510, 2515, 2520, 2525, 2530, 2550
Equity	-0	-0	0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,426,992,623	-2,426,992,623	0	0	-2,426,992,623	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	0	-0	4080
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	4225
Specific Service Charges	-7,404,026	-7,404,026	0	0	-7,404,026	4235
Other Distribution Revenue	-6,660,133	-6,660,133	0	0	-6,660,133	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-7,270,970	-7,270,970	0	0	-7,270,970	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,922,552,889	1,922,552,889	0	0	1,922,552,889	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	59,627,953	59,627,953	0	0	59,627,953	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	46,548,093	46,548,093	0	0	46,548,093	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
Billing and Collection (Working Capital)	32,388,546	32,388,546	0	0	32,388,546	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,561,824	3,561,824	0	0	3,561,824	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	1,539,975	1,539,975	0	0	1,539,975	5415
Administrative and General Expenses (Working Capital)	35,065,948	35,065,948	0	0	35,065,948	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,720,000	2,720,000	0	0	2,720,000	5635, 6210
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	0	7,000,000	5335
Advertising Expenses	-0	-0	0	0	-0	5515, 5660
Charitable Contributions	-0	-0	0	0	-0	6205
Amortization of Assets	153,723,682	153,723,682	0	0	153,723,682	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045

1-2 ADJUSTED ACCOUNTING DATA

	2008 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2008 Accounts as Adjusted for 2008 Rate Calculation	
	$	$	$	$	$	
Income Tax Expense - Unclassified	-0	-0	0	0	-0	6110, 6115
Other Distribution Expenses	7,571,070	7,571,070	0	0	7,571,070	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 5165, 5170, 5172, 5178, 5185, 5190, 5192, 5195
Unclassified Expenses	-0	-0	0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,621,088,567	1,621,088,567	0	0	1,531,875,807	Total

1-2 ADJUSTED ACCOUNTING DATA

	2008 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2008 Accounts as Adjusted for 2008 Rate Calculation
	$	$	$	$	$
SUMMARY FINANCIAL INFORMATION					
DISTRIBUTION ASSETS:					
Land and Buildings	67,731,017	67,731,017	0	0	65,637,261
TS Primary Above 50	7,542,507	7,542,507	0	0	4,792,507
DS	179,487,101	179,487,101	0	0	169,889,995
Poles, Wires	2,328,854,397	2,328,854,397	0	0	2,267,582,846
Line Transformers	637,012,017	637,012,017	0	0	613,639,344
Services and Meters	307,375,831	307,375,831	0	0	243,794,874
General Plant	102,927,167	102,927,167	0	0	104,553,612
Equipment	163,174,175	163,174,175	0	0	157,978,497
IT Assets	197,063,927	197,063,927	0	0	186,534,680
CDM Assets	-0	-0	0	0	0
Other Distribution Assets	64,417,127	64,417,127	0	0	62,982,570
Contributions and Grants	-233,735,937	-233,735,937	0	0	-219,874,258
TOTAL DISTRIBUTION ASSETS	**3,821,849,330**	**3,821,849,330**	**0**	**0**	**3,657,511,928**
NET FIXED DISTRIBUTION ASSETS:					
Total Distribution Assets (as above) - LESS:					
Accumulated Amortization	-2,020,430,992	-2,020,430,992	0	0	-1,945,306,351
NET FIXED DISTRIBUTION ASSETS	**1,801,418,338**	**1,801,418,338**	**0**	**0**	**1,712,205,577**
NET SALES REVENUE					
Sales of Electricity	-2,426,992,623	-2,426,992,623	0	0	-2,426,992,623
Power Supply Expenses (Working Capital)	1,922,552,889	1,922,552,889	0	0	1,922,552,889
SALES OF ELECTRICITY NET OF COST OF POWER	-504,439,734	-504,439,734	0	0	-504,439,734
DISTRIBUTION REVENUE					
Distribution Services Revenue	-0	-0	0	0	-0
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000
Specific Service Charges	-7,404,026	-7,404,026	0	0	-7,404,026
Other Distribution Revenue	-6,660,133	-6,660,133	0	0	-6,660,133
TOTAL DISTRIBUTION REVENUE	**-19,064,159**	**-19,064,159**	**0**	**0**	**-19,064,159**

1-2 ADJUSTED ACCOUNTING DATA

	2008 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2008 Accounts as Adjusted for 2008 Rate Calculation	
	$	$	$	$	$	
DISTRIBUTION EXPENSES (before PILS):						
Operation (Working Capital)	59,627,953	59,627,953	0	0	59,627,953	
Maintenance (Working Capital)	46,548,093	46,548,093	0	0	46,548,093	
Billing and Collection (Working Capital)	32,388,546	32,388,546	0	0	32,388,546	
Community Relations (Working Capital)	3,561,824	3,561,824	0	0	3,561,824	
Community Relations - CDM (Working Capital)	1,539,975	1,539,975	0	0	1,539,975	
Administrative and General Expenses (Working Capital)	35,065,948	35,065,948	0	0	35,065,948	
Insurance Expense (Working Capital)	2,720,000	2,720,000	0	0	2,720,000	
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	0	7,000,000	
Advertising Expenses	-0	-0	0	0	-0	
Charitable Contributions	-0	-0	0	0	-0	
Amortization of Assets	153,723,682	153,723,682	0	0	153,723,682	
Other Distribution Expenses	7,571,070	7,571,070	0	0	7,571,070	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**349,747,092**	**349,747,092**	**0**	**0**	**349,747,092**	to pils
PILS AMOUNT						
WORKING CAPITAL CALCULATION						
Cost of Power						
Power Supply Expenses (Working Capital)	1,922,552,889	1,922,552,889	0	0	1,922,552,889	
TOTAL COST OF POWER	1,922,552,889	1,922,552,889	0	0	1,922,552,889	
Expenses						
Operation (Working Capital)	59,627,953	59,627,953	0	0	59,627,953	
Maintenance (Working Capital)	46,548,093	46,548,093	0	0	46,548,093	
Billing and Collection (Working Capital)	32,388,546	32,388,546	0	0	32,388,546	
Community Relations (Working Capital)	3,561,824	3,561,824	0	0	3,561,824	
Community Relations - CDM (Working Capital)	1,539,975	1,539,975	0	0	1,539,975	
Administrative and General Expenses (Working Capital)	35,065,948	35,065,948	0	0	35,065,948	
Insurance Expense (Working Capital)	2,720,000	2,720,000	0	0	2,720,000	
Bad Debt Expense (Working Capital)	7,000,000	7,000,000	0	0	7,000,000	
Advertising Expenses	0	0	0	0	-0	
Charitable Contributions	0	0	0	0	-0	
Other Distribution Expenses	7,571,070	7,571,070	0	0	7,571,070	
TOTAL EXPENSES	196,023,410	196,023,410	0	0	196,023,410	
TOTAL FOR WORKING CAPITAL CALCULATION	**2,118,576,299**	**2,118,576,299**	**0**	**0**	**2,118,576,299**	

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2008 Base Year

2-1 RATE BASE

Net Fixed Assets			**1,712,205,577**
Working Capital Allowance			
Working Capital *(from Sheet "1-2 ADJUSTED ACCOUNTING DATA")*		2,118,576,299	
Working Capital Allowance			
- Cost of Power @ 10.63%		**204,367,372**	
- EXPENSES			
- OM&A Expense @ 14.12%	27,678,505		
- Interest on Long term debt @ 7.73%	4,967,554		
- Income and CAPITAL Tax @ 9.18%	2,633,522		
- Debt Retirement Charge (@ 10.47%	18,886,494		
- GST (See 2-1-1 GST - Lead Lag Study)	7,841,981		
		62,008,057	**266,375,430**
RATE BASE			**1,978,581,007**

THESL - GST WORKING CAPITAL REQUIREMENT - Calculation Model
Based upon Navigant Lead Lag Study Methodology below (note 1).
(All Data in $s except Lead/Lag Days)

	Forecast Year Amounts ($s) (A)	6% GST (B)	Net Lead (lag) Days (C)	WC Requirement GST Benefit (Cost) (D)
1 **GST CATEGORY**				
2 Revenue	2,448,554,800	146,913,288	-18.49	(7,444,121)
3 Cost of power	1,922,552,889	(115,353,173)	43.58	13,773,906
4 OM&A Expenses	196,023,410	(11,761,405)	46.93	1,512,196
5 **TOTAL**		**19,798,710**		**7,841,981**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2008 Base Year

2-2 COST OF CAPITAL (Input)

Cost of Capital

Deemed Debt Rate and D/E Structures

Rate Base: (from Sheet *Ratebase Calc.*)	$1,978,581,007
Size of LDC (based on Rate Base)	Large
Deemed Debt (based on Size)	62.5%
Deemed Equity (based on Size)	37.5%

Table 3-1
Deemed Common Equity and Debt Ratios and Debt Cost Rates

Size of Utility Rate Base	Descriptor	Equity	Debt	DR
		CER %	(1-CER)%	
Greater than $1.0 Billion	Large	37.5%	62.5%	5.55%

Debt Rate (DR)

Deemed or proposed Debt Rate for Revenue Requirement calculation.	5.55%

Return on Equity

Utility's Proposed ROE	8.83%

Cost of Capital

Cost of Capital	6.78%

2008 Test Year

	Principal	Component	Cost Rate	Return Component	Weighted by Component	Weighted by Cost Rate
	($ millions)	(%)	(%)	(%)		
Medium and Long-Term Debt	1,157.5	59%	5.57%	0.00	0.94	64.51
Short Term Debt	79.1	4%	5.17%	0.00	0.06	4.09
	1,236.6	63%		0.00		5.55%
Preferred Shares	-	0%	-	-		
Common Equity	742.0	38%	8.83%	0.00		65.53
						8.83%
	1,978.6	1.0		0.00		6.78%

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2008 Base Year

3-1 DATA for PILS MODEL

Item	Source		$ Amount as Adjusted	
Net Income before consideration of PILS				
Revenue Requirement other than PILS	*Sheet 4-1*		483,878,130	
Distribution Expenses other than PILS and interest	*Sheet 1-2*		349,747,092	to detail
(Note: "Book" interest expense and "book" income tax expense are not included in Distribution Expenses above)				
			134,131,038	
Calculated Interest				
Rate Base	*Sheet 2-1*	1,978,581,007		
x Debt Component	*Sheet 2-2*	62.50%		
x Debt Rate reflected in Revenue Requirement	*Sheet 2-2*	5.55%	68,606,142	
Target Net Income before consideration of PILS (= Target Net Income reflecting PILS)			**65,524,896**	

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2008 Base Year

3-2 OUTPUT from PILS MODEL

	$
PILS Amount from PILS Model	**40,850,253**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2008 Base Year

4-1 SERVICE REVENUE REQUIREMENT

This sheet calculates the Revenue Requirement using adjusted information from previous sheets and brings in the income tax amount from the PILS Model.

	$	$
Rate Base *(from sheet 2-1)*	1,978,581,007	
x Cost of Capital *(from sheet 2-2)*	6.78%	
Return on Ratebase		**134,131,038**
Distribution Expenses (*from sheet 1-2 ADJUSTED ACCOUNTING DATA"*		**349,747,092**
Revenue Requirement Before Income Taxes		**483,878,130**
Income Taxes - from PILS Model		**40,850,253**
SERVICE REVENUE REQUIREMENT		**524,728,383**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2008 Base Year

4-4 BASE REVENUE REQUIREMENT

	$	$
Service Revenue Requirement *(from Sheet 4-1)*		**524,728,383**
LESS:		
Revenue Offsets:		
Board Approved Charges		
Specific Service Charges	7,404,026	
Late Payment Charges *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	5,000,000	
Other Distribution Revenue *(from Sheet1-2 ADJUSTED ACCOUNTING DATA)*	6,660,133	
Other Income & Deductions *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	7,270,970	
TOTAL REVENUE OFFSETS	26,335,129	**26,335,129**
Smart Metering		
Base Revenue Requirement		**498,393,254**

(defined as SERVICE REVENUE REQUIREMENT NET OF REVENUE OFFSETS)

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009 Base Year

ADJ 3 (DISTRIBUTION EXPENSES -TIER 1)

Tier 1 Adjustments related to ***Distribution Expenses*** *(Sheet 1 of 3).*

			posted to account
5) Low Voltage/Wheeling Adjustments	**(Handbook p.13)**		
(Embedded Distributors only)			
Amount included in 2004 Trial Balance data, if any			
Incremental Amount per section A (Handbook, p. 13)			
Amount per section C (Handboook, p. 13)	255,430		
[above items to Sheet 5-5 B.R.R. #2]			
Adjustment		**255,430**	5665 - Miscellaneous General Expenses

1-2 ADJUSTED ACCOUNTING DATA

GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)

	2009 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2009 Accounts as Adjusted for 2009 Rate Calculation	
Land and Buildings	69,292,438	69,292,438	0	0	68,511,728	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	18,042,507	18,042,507	0	0	12,792,507	1815
DS	196,771,792	196,771,792	0	0	188,129,446	1820
Poles, Wires	2,462,576,213	2,462,576,213	0	0	2,395,715,305	1830, 1835, 1840, 1845
Line Transformers	678,687,164	678,687,164	0	0	657,849,590	1850
Services and Meters	365,405,102	365,405,102	0	0	336,390,466	1855, 1860
General Plant	108,794,710	108,794,710	0	0	105,860,938	1908, 1910
Equipment	172,618,310	172,618,310	0	0	167,896,243	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	235,661,750	235,661,750	0	0	216,362,838	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	0	1565 (new account)
Other Distribution Assets	66,182,120	66,182,120	0	0	65,299,624	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-253,659,242	-253,659,242	0	0	-243,697,589	1995
Accumulated Amortization	-2,181,317,301	-2,181,317,301	0	0	-2,100,874,147	2105, 2120
Non-Distribution Asset	-0	-0	0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	989,000	989,000	0	0	989,000	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 1515, 1516, 1518, 1520, 1525, 1530, 1540, 1545, 1548, 1560, 1562, 1563, 1570, 1571, 1572, 1574, 1580, 1582, 1584, 1586, 1588, 1605, 2060, 2140
Liability	-0	-0	0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 2510, 2515, 2520, 2525, 2530, 2550
Equity	-0	-0	0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,464,836,833	-2,464,836,833	0	0	-2,464,836,833	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	0	-0	4080
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	4225
Specific Service Charges	-7,532,201	-7,532,201	0	0	-7,532,201	4235
Other Distribution Revenue	-6,898,143	-6,898,143	0	0	-6,898,143	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-2,301,658	-2,301,658	0	0	-2,301,658	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,923,661,344	1,923,661,344	0	0	1,923,661,344	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	65,352,539	65,352,539	0	0	65,352,539	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	48,775,793	48,775,793	0	0	48,775,793	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175

Billing and Collection (Working Capital)	32,819,695	32,819,695	0	0	32,819,695	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,655,723	3,655,723	0	0	3,655,723	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	1,618,945	1,618,945	0	0	1,618,945	5415
Administrative and General Expenses (Working Capital)	36,170,973	36,170,973	0	0	36,170,973	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,770,000	2,770,000	0	0	2,770,000	5635, 6210
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	5335
Advertising Expenses	-0	-0	0	0	-0	5515, 5660
Charitable Contributions	-0	-0	0	0	-0	6205
Amortization of Assets	160,886,305	160,886,305	0	0	160,886,305	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045
Income Tax Expense - Unclassified	-0	-0	0	0	-0	6110, 6115
Other Distribution Expenses	7,795,116	7,795,116	0	0	7,795,116	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 5165, 5170, 5172, 5178, 5185, 5190, 5192, 5195
Unclassified Expenses	-0	-0	0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,744,482,159	1,744,482,159	0	0	1,675,663,547	Total

SUMMARY FINANCIAL INFORMATION

DISTRIBUTION ASSETS:

Land and Buildings	69,292,438	69,292,438	0	0	68,511,728
TS Primary Above 50	18,042,507	18,042,507	0	0	12,792,507
DS	196,771,792	196,771,792	0	0	188,129,446
Poles, Wires	2,462,576,213	2,462,576,213	0	0	2,395,715,305
Line Transformers	678,687,164	678,687,164	0	0	657,849,590
Services and Meters	365,405,102	365,405,102	0	0	336,390,466
General Plant	108,794,710	108,794,710	0	0	105,860,938
Equipment	172,618,310	172,618,310	0	0	167,896,243
IT Assets	235,661,750	235,661,750	0	0	216,362,838
CDM Assets	-0	-0	0	0	0
Other Distribution Assets	66,182,120	66,182,120	0	0	65,299,624
Contributions and Grants	-253,659,242	-253,659,242	0	0	-243,697,589
TOTAL DISTRIBUTION ASSETS	**4,120,372,863**	**4,120,372,863**	**0**	**0**	**3,971,111,096**

NET FIXED DISTRIBUTION ASSETS:

Total Distribution Assets (as above) - LESS:					
Accumulated Amortization	-2,181,317,301	-2,181,317,301	0	0	-2,100,874,147
NET FIXED DISTRIBUTION ASSETS	**1,939,055,561**	**1,939,055,561**	**0**	**0**	**1,870,236,950**

NET SALES REVENUE

Sales of Electricity	-2,464,836,833	-2,464,836,833	0	0	-2,464,836,833
Power Supply Expenses (Working Capital)	1,923,661,344	1,923,661,344	0	0	1,923,661,344
SALES OF ELECTRICITY NET OF COST OF POWER	-541,175,489	-541,175,489	0	0	-541,175,489

DISTRIBUTION REVENUE

Distribution Services Revenue	-0	-0	0	0	-0

Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	
Specific Service Charges	-7,532,201	-7,532,201	0	0	-7,532,201	
Other Distribution Revenue	-6,898,143	-6,898,143	0	0	-6,898,143	
TOTAL DISTRIBUTION REVENUE	**-19,430,344**	**-19,430,344**	**0**	**0**	**-19,430,344**	
DISTRIBUTION EXPENSES (before PILS):						
Operation (Working Capital)	65,352,539	65,352,539	0	0	65,352,539	
Maintenance (Working Capital)	48,775,793	48,775,793	0	0	48,775,793	
Billing and Collection (Working Capital)	32,819,695	32,819,695	0	0	32,819,695	
Community Relations (Working Capital)	3,655,723	3,655,723	0	0	3,655,723	
Community Relations - CDM (Working Capital)	1,618,945	1,618,945	0	0	1,618,945	
Administrative and General Expenses (Working Capital)	36,170,973	36,170,973	0	0	36,170,973	
Insurance Expense (Working Capital)	2,770,000	2,770,000	0	0	2,770,000	
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	
Advertising Expenses	-0	-0	0	0	-0	
Charitable Contributions	-0	-0	0	0	-0	
Amortization of Assets	160,886,305	160,886,305	0	0	160,886,305	
Other Distribution Expenses	7,795,116	7,795,116	0	0	7,795,116	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**367,345,089**	**367,345,089**	**0**	**0**	**367,345,089**	to pils
PILS AMOUNT						
WORKING CAPITAL CALCULATION						
Cost of Power						
Power Supply Expenses (Working Capital)	1,923,661,344	1,923,661,344	0	0	1,923,661,344	
TOTAL COST OF POWER	1,923,661,344	1,923,661,344	0	0	1,923,661,344	
Expenses						
Operation (Working Capital)	65,352,539	65,352,539	0	0	65,352,539	
Maintenance (Working Capital)	48,775,793	48,775,793	0	0	48,775,793	
Billing and Collection (Working Capital)	32,819,695	32,819,695	0	0	32,819,695	
Community Relations (Working Capital)	3,655,723	3,655,723	0	0	3,655,723	
Community Relations - CDM (Working Capital)	1,618,945	1,618,945	0	0	1,618,945	
Administrative and General Expenses (Working Capital)	36,170,973	36,170,973	0	0	36,170,973	
Insurance Expense (Working Capital)	2,770,000	2,770,000	0	0	2,770,000	
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	
Advertising Expenses	0	0	0	0	-0	
Charitable Contributions	0	0	0	0	-0	
Other Distribution Expenses	7,795,116	7,795,116	0	0	7,795,116	
TOTAL EXPENSES	206,458,784	206,458,784	0	0	206,458,784	
TOTAL FOR WORKING CAPITAL CALCULATION	**2,130,120,128**	**2,130,120,128**	**0**	**0**	**2,130,120,128**	

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009 Base Year

2-1 RATE BASE

Net Fixed Assets			**1,870,236,950**
Working Capital Allowance			
Working Capital *(from Sheet "1-2 ADJUSTED ACCOUNTING DATA")*		2,130,120,128	
Working Capital Allowance			
- Cost of Power @ 10.63%		**204,485,201**	
- EXPENSES			
- OM&A Expense @ 14.12%	29,151,980		
- Interest on Long term debt @ 7.73%	5,182,043		
- Income, and Capital Tax @ 9.18%	2,540,503		
- Debt Retirement Charge (@ 10.47%	18,884,451		
- GST (See 2-1-1 GST - Lead Lag Study)	7,814,646		
		63,573,624	**268,058,825**
RATE BASE			**2,138,295,774**

THESL - GST WORKING CAPITAL REQUIREMENT - Calculation Model
Based upon Navigant Lead Lag Study Methodology below (note 1).
(All Data in $s except Lead/Lag Days)

		Forecast Year Amounts ($s) (A)	6% GST (B)	Net Lead (lag) Days (C)	WC Requirement GST Benefit (Cost) (D)
1	**GST CATEGORY**				
2	Revenue	2,486,637,276	149,198,237	-18.49	(7,559,900)
3	Cost of power	1,923,661,344	(115,419,681)	43.58	13,781,848
4	OM&A Expenses	206,458,784	(12,387,527)	46.93	1,592,699
5	**TOTAL**		**21,391,029**		**7,814,646**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009 Base Year

2-2 COST OF CAPITAL (Input)

Cost of Capital

Deemed Debt Rate and D/E Structures

Rate Base: (from Sheet *Ratebase Calc.*)	$2,138,295,774
Size of LDC (based on Rate Base)	Large
Deemed Debt (based on Size)	60%
Deemed Equity (based on Size)	40%

Table 3-1
Deemed Common Equity and Debt Ratios and Debt Cost Rates

Size of Utility Rate Base	Descriptor	Equity	Debt	DR
		CER %	(1-CER)%	
Greater than $1.0 Billion	Large	40%	60%	5.57%

Debt Rate (DR)

Deemed or proposed Debt Rate for Revenue Requirement calculation.	5.57%

Return on Equity

Utility's Proposed ROE	9.06%

Cost of Capital

Cost of Capital	6.96%

2009 Test Year

	Principal	Component	Cost Rate	Return Component	Weighted by Component	Weighted by Cost Rate
	($ millions)	(%)	(%)	(%)		
Medium and Long-Term Debt	1,197.4	56.0	5.59%	0.03	0.93	66.99
Short Term Debt	85.5	4.0	5.24%	0.00	0.07	4.48
	1,283.0	60.0		0.03		**5.57%**
Preferred Shares	-	-	-	-		
Common Equity	855.3	40.0	9.06%	0.04		77.46
	855.3					**9.06%**
	2,138.3	100.0		0.07		**6.96%**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009

3-1 DATA for PILS MODEL

Item	Source		$ Amount as Adjusted	
Net Income before consideration of PILS				
Revenue Requirement other than PILS	*Sheet 4-1*		516,277,082	
Distribution Expenses other than PILS and interest	*Sheet 1-2*		367,345,089	to detail
(Note: "Book" interest expense and "book" income tax expense are not included in Distribution Expenses above)				
			148,931,994	
Calculated Interest				
Rate Base	*Sheet 2-1*	2,138,295,774		
x Debt Component	*Sheet 2-2*	60.00%		
x Debt Rate reflected in Revenue Requirement	*Sheet 2-2*	5.57%	71,473,599	
Target Net Income before consideration of PILS (= Target Net Income reflecting PILS)			**77,458,394**	

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009 Base Year

3-2 OUTPUT from PILS MODEL

	$
PILS Amount from PILS Model	39,469,707

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009 Base Year

4-1 SERVICE REVENUE REQUIREMENT

This sheet calculates the Revenue Requirement using adjusted information from previous sheets and brings in the income tax amount from the PILS Model.

	$	$
Rate Base *(from sheet 2-1)*	2,138,295,774	
x Cost of Capital *(from sheet 2-2)*	6.96%	
Return on Ratebase		**148,931,994**
Distribution Expenses (*from sheet 1-2 ADJUSTED ACCOUNTING DATA"*		**367,345,089**
Revenue Requirement Before Income Taxes		**516,277,082**
Income Taxes - from PILS Model		**39,469,707**
SERVICE REVENUE REQUIREMENT		**555,746,789**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2009 Base Year

4-4 BASE REVENUE REQUIREMENT

	$	$
Service Revenue Requirement *(from Sheet 4-1)*		**555,746,789**
LESS:		
Revenue Offsets:		
Board Approved Charges		
Specific Service Charges	7,532,201	
Late Payment Charges *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	5,000,000	
Other Distribution Revenue *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	6,898,143	
Other Income & Deductions *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	2,301,658	
TOTAL REVENUE OFFSETS	21,732,002	**21,732,002**
Smart Metering		
Base Revenue Requirement		**534,014,787**

(defined as SERVICE REVENUE REQUIREMENT NET OF REVENUE OFFSETS)

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010 Base Year

ADJ 3 (DISTRIBUTION EXPENSES -TIER 1)

Tier 1 Adjustments related to ***Distribution Expenses*** *(Sheet 1 of 3).*

			posted to account
5) Low Voltage/Wheeling Adjustments	**(Handbook p.13)**		
(Embedded Distributors only)			
Amount included in 2004 Trial Balance data, if any			
Incremental Amount per section A (Handbook, p. 13)			
Amount per section C (Handboook, p. 13)	255,430		
[above items to Sheet 5-5 B.R.R. #2]			
Adjustment		**255,430**	5665 - Miscellaneous General Expenses

1-2 ADJUSTED ACCOUNTING DATA

GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)

	2010 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2010 Accounts as Adjusted for 2010 Rate Calculation	
Land and Buildings	71,388,932	71,388,932	0	0	70,340,685	1805, 1806, 1808, 1810, 1905, 1906
TS Primary Above 50	39,042,507	39,042,507	0	0	28,542,507	1815
DS	214,043,561	214,043,561	0	0	205,407,677	1820
Poles, Wires	2,606,093,730	2,606,093,730	0	0	2,534,334,971	1830, 1835, 1840, 1845
Line Transformers	723,416,319	723,416,319	0	0	701,051,741	1850
Services and Meters	406,278,004	406,278,004	0	0	385,841,553	1855, 1860
General Plant	117,445,819	117,445,819	0	0	113,120,264	1908, 1910
Equipment	183,466,845	183,466,845	0	0	178,042,578	1915, 1930, 1935, 1940, 1945, 1950, 1955, 1960
IT Assets	261,120,000	261,120,000	0	0	248,390,875	1920, 1925
CDM Expenditures and Recoveries	-0	-0	0	0	0	1565 (new account)
Other Distribution Assets	67,895,668	67,895,668	0	0	67,038,894	1608, 1825, 1970, 1975, 1980, 1990, 2005, 2010, 2050
Contributions and Grants	-273,582,548	-273,582,548	0	0	-263,620,895	1995
Accumulated Amortization	-2,355,047,277	-2,355,047,277	0	0	-2,268,182,289	2105, 2120
Non-Distribution Asset	-0	-0	0	0	-0	1606, 1610, 1615, 1616, 1620, 1630, 1635, 1640, 1645, 1650, 1655, 1660, 1665, 1670, 1675, 1680, 1685, 1705, 1706, 1708, 1710, 1715, 1720, 1725, 1730, 1735, 1740, 1745, 1865, 1870, 1875, 1965, 1985, 2020, 2030, 2040, 2055, 2065, 2070, 2075, 2160, 2180
Unclassified Asset	1,292,000	1,292,000	0	0	1,292,000	1005, 1010, 1020, 1030, 1040, 1060, 1070, 1100, 1102, 1104, 1105, 1110, 1120, 1130, 1140, 1150, 1170, 1180, 1190, 1200, 1210, 1305, 1330, 1340, 1350, 1405, 1408, 1410, 1415, 1425, 1445, 1455, 1460, 1465, 1470, 1475, 1480, 1485, 1490, 1505, 1508, 1510, 1515, 1516, 1518, 1520, 1525, 1530, 1540, 1545, 1548, 1560, 1562, 1563, 1570, 1571, 1572, 1574, 1580, 1582, 1584, 1586, 1588, 1605, 2060, 2140
Liability	-0	-0	0	0	-0	2205, 2208, 2210, 2215, 2220, 2225, 2240, 2242, 2250, 2252, 2254, 2256, 2260, 2262, 2264, 2268, 2270, 2272, 2285, 2290, 2292, 2294, 2296, 2305, 2306, 2308, 2310, 2315, 2320, 2325, 2330, 2335, 2340, 2345, 2348, 2350, 2405, 2410, 2415, 2425, 2435, 2505, 2510, 2515, 2520, 2525, 2530, 2550
Equity	-0	-0	0	0	-0	3005, 3008, 3010, 3020, 3022, 3026, 3030, 3035, 3040, 3045, 3046, 3047, 3048, 3049, 3055, 3065
Sales of Electricity	-2,489,841,516	-2,489,841,516	0	0	-2,489,841,516	4006, 4010, 4015, 4020, 4025, 4030, 4035, 4040, 4045, 4050, 4055, 4060, 4062, 4064 (new account), 4066, 4068
Distribution Services Revenue	-0	-0	0	0	-0	4080
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000	4225
Specific Service Charges	-7,699,376	-7,699,376	0	0	-7,699,376	4235
Other Distribution Revenue	-7,169,193	-7,169,193	0	0	-7,169,193	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Revenue - Unclassified	-0	-0	0	0	-0	4105, 4110, 4230, 4375, 4380, 4385
Other Income & Deductions	-4,414,571	-4,414,571	0	0	-4,414,571	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4390, 4395, 4398, 4405, 4415
Power Supply Expenses (Working Capital)	1,925,554,529	1,925,554,529	0	0	1,925,554,529	4705, 4708, 4710, 4712, 4714, 4716, 4730, 5685
Other Power Supply Expenses	-0	-0	0	0	-0	4715, 4720, 4725, 5205, 5210, 5215
Operation (Working Capital)	68,675,900	68,675,900	0	0	68,675,900	5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
Maintenance (Working Capital)	51,347,923	51,347,923	0	0	51,347,923	5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
Billing and Collection (Working Capital)	33,212,388	33,212,388	0	0	33,212,388	5305, 5310, 5315, 5320, 5325, 5330, 5340
Community Relations (Working Capital)	3,716,148	3,716,148	0	0	3,716,148	5405, 5410, 5420, 5425
Community Relations - CDM (Working Capital)	1,736,566	1,736,566	0	0	1,736,566	5415
Administrative and General Expenses (Working Capital)	36,754,964	36,754,964	0	0	36,754,964	5605, 5610, 5615, 5620, 5625, 5630, 5640, 5645, 5650, 5655, 5665, 5670, 5675, 5680
Insurance Expense (Working Capital)	2,820,000	2,820,000	0	0	2,820,000	5635, 6210
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	5335
Advertising Expenses	-0	-0	0	0	-0	5515, 5660

1-2 ADJUSTED ACCOUNTING DATA

	2010 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2010 Accounts as Adjusted for 2010 Rate Calculation	
Charitable Contributions	-0	-0	0	0	-0	6205
Amortization of Assets	174,420,111	174,420,111	0	0	174,420,111	5705, 5710, 5715, 5730, 5735, 5740
Other Amortization - Unclassified	-0	-0	0	0	-0	5720, 5725
Interest Expense - Unclassifed	-0	-0	0	0	-0	6005, 6010, 6015, 6020, 6025, 6030, 6035, 6040, 6042, 6045
Income Tax Expense - Unclassified	-0	-0	0	0	-0	6110, 6115
Other Distribution Expenses	8,028,970	8,028,970	0	0	8,028,970	5505, 5510, 5520, 6105, 6215, 6225
Non-Distribution Expenses	-0	-0	0	0	-0	4505, 4510, 4515, 4520, 4525, 4530, 4535, 4540, 4545, 4550, 4555, 4560, 4565, 4605, 4610, 4615, 4620, 4625, 4630, 4635, 4640, 4805, 4810, 4815, 4820, 4825, 4830, 4835, 4840, 4845, 4850, 4905, 4910, 4946, 4930, 4935, 4940, 4945, 4950, 4960, 4965, 5060, 5165, 5170, 5172, 5178, 5185, 5190, 5192, 5195
Unclassified Expenses	-0	-0	0	0	-0	6305, 6310, 6315, 6405, 6410, 6415
	1,862,496,401	1,862,496,401	0	0	1,801,243,402	Total

SUMMARY FINANCIAL INFORMATION

DISTRIBUTION ASSETS:

Land and Buildings	71,388,932	71,388,932	0	0	70,340,685
TS Primary Above 50	39,042,507	39,042,507	0	0	28,542,507
DS	214,043,561	214,043,561	0	0	205,407,677
Poles, Wires	2,606,093,730	2,606,093,730	0	0	2,534,334,971
Line Transformers	723,416,319	723,416,319	0	0	701,051,741
Services and Meters	406,278,004	406,278,004	0	0	385,841,553
General Plant	117,445,819	117,445,819	0	0	113,120,264
Equipment	183,466,845	183,466,845	0	0	178,042,578
IT Assets	261,120,000	261,120,000	0	0	248,390,875
CDM Assets	-0	-0	0	0	0
Other Distribution Assets	67,895,668	67,895,668	0	0	67,038,894
Contributions and Grants	-273,582,548	-273,582,548	0	0	-263,620,895
TOTAL DISTRIBUTION ASSETS	**4,416,608,837**	**4,416,608,837**	**0**	**0**	**4,268,490,850**

NET FIXED DISTRIBUTION ASSETS:

Total Distribution Assets (as above) - LESS:					
Accumulated Amortization	-2,355,047,277	-2,355,047,277	0	0	-2,268,182,289
NET FIXED DISTRIBUTION ASSETS	**2,061,561,560**	**2,061,561,560**	**0**	**0**	**2,000,308,561**

NET SALES REVENUE

Sales of Electricity	-2,489,841,516	-2,489,841,516	0	0	-2,489,841,516
Power Supply Expenses (Working Capital)	1,925,554,529	1,925,554,529	0	0	1,925,554,529
SALES OF ELECTRICITY NET OF COST OF POWER	-564,286,987	-564,286,987	0	0	-564,286,987

DISTRIBUTION REVENUE

Distribution Services Revenue	-0	-0	0	0	-0
Late Payment Charges	-5,000,000	-5,000,000	0	0	-5,000,000
Specific Service Charges	-7,699,376	-7,699,376	0	0	-7,699,376
Other Distribution Revenue	-7,169,193	-7,169,193	0	0	-7,169,193
TOTAL DISTRIBUTION REVENUE	**-19,868,569**	**-19,868,569**	**0**	**0**	**-19,868,569**

1-2 ADJUSTED ACCOUNTING DATA

	2010 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2010 Accounts as Adjusted for 2010 Rate Calculation	
DISTRIBUTION EXPENSES (before PILS):						
Operation (Working Capital)	68,675,900	68,675,900	0	0	68,675,900	
Maintenance (Working Capital)	51,347,923	51,347,923	0	0	51,347,923	
Billing and Collection (Working Capital)	33,212,388	33,212,388	0	0	33,212,388	
Community Relations (Working Capital)	3,716,148	3,716,148	0	0	3,716,148	
Community Relations - CDM (Working Capital)	1,736,566	1,736,566	0	0	1,736,566	
Administrative and General Expenses (Working Capital)	36,754,964	36,754,964	0	0	36,754,964	
Insurance Expense (Working Capital)	2,820,000	2,820,000	0	0	2,820,000	
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	
Advertising Expenses	-0	-0	0	0	-0	
Charitable Contributions	-0	-0	0	0	-0	
Amortization of Assets	174,420,111	174,420,111	0	0	174,420,111	
Other Distribution Expenses	8,028,970	8,028,970	0	0	8,028,970	
TOTAL DISTRIBUTION EXPENSES (before PILs)	**388,212,969**	**388,212,969**	**0**	**0**	**388,212,969**	to pils
PILS AMOUNT						
WORKING CAPITAL CALCULATION						
Cost of Power						
Power Supply Expenses (Working Capital)	1,925,554,529	1,925,554,529	0	0	1,925,554,529	
TOTAL COST OF POWER	1,925,554,529	1,925,554,529	0	0	1,925,554,529	
Expenses						
Operation (Working Capital)	68,675,900	68,675,900	0	0	68,675,900	
Maintenance (Working Capital)	51,347,923	51,347,923	0	0	51,347,923	
Billing and Collection (Working Capital)	33,212,388	33,212,388	0	0	33,212,388	
Community Relations (Working Capital)	3,716,148	3,716,148	0	0	3,716,148	
Community Relations - CDM (Working Capital)	1,736,566	1,736,566	0	0	1,736,566	
Administrative and General Expenses (Working Capital)	36,754,964	36,754,964	0	0	36,754,964	
Insurance Expense (Working Capital)	2,820,000	2,820,000	0	0	2,820,000	
Bad Debt Expense (Working Capital)	7,500,000	7,500,000	0	0	7,500,000	
Advertising Expenses	0	0	0	0	-0	
Charitable Contributions	0	0	0	0	-0	
Other Distribution Expenses	8,028,970	8,028,970	0	0	8,028,970	
TOTAL EXPENSES	213,792,858	213,792,858	0	0	213,792,858	
TOTAL FOR WORKING CAPITAL CALCULATION	**2,139,347,387**	**2,139,347,387**	**0**	**0**	**2,139,347,387**	

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010 Base Year

2-1 RATE BASE

Net Fixed Assets			**2,000,308,561**
Working Capital Allowance			
Working Capital *(from Sheet "1-2 ADJUSTED ACCOUNTING DATA")*		2,139,347,387	
Working Capital Allowance			
- Cost of Power @ 10.63%		**204,686,446**	
- EXPENSES			
- OM&A Expense @ 14.12%	30,187,552		
- Interest on Long term debt @ 7.73%	5,553,816		
- Income, and Capital Tax @ 9.18%	2,445,887		
- Debt Retirement Charge (@ 10.47%	18,899,925		
- GST (See 2-1-1 GST - Lead Lag Study)	7,807,880		
		64,895,061	**269,581,507**
RATE BASE			**2,269,890,068**

THESL - GST WORKING CAPITAL REQUIREMENT - Calculation Model
Based upon Navigant Lead Lag Study Methodology below (note 1).
(All Data in $s except Lead/Lag Days)

		Forecast Year Amounts ($s) (A)	6% GST (B)	Net Lead (lag) Days (C)	WC Requirement GST Benefit (Cost) (D)
1	**GST CATEGORY**				
2	Revenue	2,511,933,893	150,716,034	-18.49	(7,636,807)
3	Cost of power	1,925,554,529	(115,533,272)	43.58	13,795,411
4	OM&A Expenses	213,792,858	(12,827,571)	46.93	1,649,276
5	**TOTAL**		**22,355,190**		**7,807,880**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010 Base Year

2-2 COST OF CAPITAL (Input)

Cost of Capital

Deemed Debt Rate and D/E Structures

Rate Base: (from Sheet *Ratebase Calc.*)	$2,269,890,068
Size of LDC (based on Rate Base)	Large
Deemed Debt (based on Size)	60%
Deemed Equity (based on Size)	40%

Table 3-1 — Common Equity and Debt Ratios and Debt Cost Rates

Size of Utility Rate Base	Descriptor	Equity CER %	Debt (1-CER)%	Deemed DR
Greater than $1.0 Billion	Large	40%	60%	5.64%

Debt Rate (DR)

Deemed or proposed Debt Rate for Revenue Requirement calculation.	5.64%

Return on Equity

Utility's Proposed ROE	9.19%

Cost of Capital

Cost of Capital	7.06%

2010 Test Year

	Principal	Component	Cost Rate	Return Component	Weighted by Component	Weighted by Cost Rate
	($ millions)	(%)	(%)	(%)		
Medium and Long-Term Debt	1,271.1	56.0	5.67%	0.03	0.93	72.1
Short Term Debt	90.8	4.0	5.28%	0.00	0.07	4.8
	1,361.9	60.0		0.03		**5.64%**
Preferred Shares	-	-	-	-		
Common Equity	908.0	40.0	9.19%	0.04		83.5
	908.0					**9.19%**
	2,269.9	100.0		0.07		**7.06%**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010

3-1 DATA for PILS MODEL

Item	Source		$ Amount as Adjusted	
Net Income before consideration of PILS				
Revenue Requirement other than PILS	*Sheet 4-1*		548,552,386	
Distribution Expenses other than PILS and interest	*Sheet 1-2*		388,212,969	to detail
(Note: "Book" interest expense and "book" income tax expense are not included in Distribution Expenses above)				
			160,339,417	
Calculated Interest				
Rate Base	*Sheet 2-1*	2,269,890,068		
x Debt Component	*Sheet 2-2*	60.00%		
x Debt Rate reflected in Revenue Requirement	*Sheet 2-2*	5.64%	76,864,002	
Target Net Income before consideration of PILS (= Target Net Income reflecting PILS)			**83,475,416**	

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010 Base Year

3-2 OUTPUT from PILS MODEL

	$
PILS Amount from PILS Model	**38,100,719**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010 Base Year

4-1 SERVICE REVENUE REQUIREMENT

This sheet calculates the Revenue Requirement using adjusted information from previous sheets and brings in the income tax amount from the PILS Model.

	$	$
Rate Base *(from sheet 2-1)*	2,269,890,068	
x Cost of Capital *(from sheet 2-2)*	7.06%	
Return on Ratebase		**160,339,417**
Distribution Expenses (*from sheet 1-2 ADJUSTED ACCOUNTING DATA"*		**388,212,969**
Revenue Requirement Before Income Taxes		**548,552,386**
Income Taxes - from PILS Model		**38,100,719**
SERVICE REVENUE REQUIREMENT		**586,653,105**

EDR 2008 MODEL

Toronto Hydro-Electric System Limited

EB-2007-0680

2010 Base Year

4-4 BASE REVENUE REQUIREMENT

	$	$
Service Revenue Requirement *(from Sheet 4-1)*		**586,653,105**
LESS:		
Revenue Offsets:		
Board Approved Charges		
Specific Service Charges	7,699,376	
Late Payment Charges *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	5,000,000	
Other Distribution Revenue *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	7,169,193	
Other Income & Deductions *(from Sheet 1-2 ADJUSTED ACCOUNTING DATA)*	4,414,571	
TOTAL REVENUE OFFSETS	24,283,140	**24,283,140**
Smart Metering		
Base Revenue Requirement		**562,369,965**

(defined as SERVICE REVENUE REQUIREMENT NET OF REVENUE OFFSETS)

RATE APPLICATION MODELS

In developing the revenue requirement for the 2008-2010 test years, THESL has employed the OEB's EDR and PILs models.

Forecasts of capital and O&M expenses at the project and department level have been developed as detailed in Exhibits C2 through G1. These forecasts were then mapped to the OEB USoA accounts and aggregated into the categories as defined in the OEB's 2006 EDR model. This model, which is filed in Exhibit P1, Tab 2, Schedules 1 to 3, was then used to develop the annual revenue requirement for test years 2008, 2009 and 2010, respectively.

The following changes were made to the logic of the OEB's EDR model:

- The calculation of working capital requirement, which was previously defined as 15 percent of expenses, has been replaced with the working capital requirement derived using the Navigant study.
- The capital structure has been adjusted to reflect the Board's December 2006 Report on Cost of Capital.

Toronto Hydro-Electric System Limited

Report on Affiliate Transactions Regulatory Compliance: Methodology and Implementation

Phase I: Methodology
Phase II: Implementation

June 2007

Executive Summary

In 2006 Toronto Hydro Corporation ("THC") initiated changes to minimize the number of shared services and inter-affiliate transactions, to develop a high level of autonomy amongst affiliates, to provide for greater regulatory clarity and to allow for a higher degree of transparency. Accordingly, several functions performed by THC were transferred to Toronto Hydro-Electric System Limited ("THESL") and other unregulated affiliates reflecting the direct nature of the services performed.

This *Report on Affiliate Transactions Regulatory Compliance: Methodology and Implementation* ("Report") documents the response of THESL to the Decision with Reasons 3.2 and Direction 3 of the Ontario Energy Board EB-2005-0421 ("OEB Decision") in the matter of the application by THESL for electricity distribution rates ("EDR") for 2006. The key objectives of the Report are to:

1. describe the context of THESL's and THC's response and actions,
2. explain THESL's methodological approach, studies and findings related to affiliate transactions, costing and transfer pricing,
3. compile or identify for reference purposes all material evidence related to the above initiatives, and
4. provide a comprehensive body of materials and evidence for THESL Regulatory Affairs to use for the 2008-2010 EDR application.

The OEB Decision directed THESL to implement an improved time-based methodology for allocating shared service costs. THESL used this opportunity to also undertake a full review of affiliate transactions transfer pricing and compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters ("ARC"). THC and THESL established an executive Steering Committee to oversee a Shared Services Project with the following phases and goals.

In *Phase I: Methodology* the Project Team established accurate product, resource and service costs, and a mechanism to allocate those costs to affiliates. A review and enhancement of source data, methodologies and business practices was instituted to:

1. create an inventory of affiliate company service transactions,
2. determine how to cost each service,
3. establish criteria for identifying potential fair market value comparisons for each service, where possible, and
4. prepare a method to fairly allocate the cost of services to affiliates.

Following this phase the methodology underwent an independent review.

In *Phase II: Implementation*, the Project Team implemented the new methods and applied newly collected data in the preparation of:

1. 2007 transfer pricing,
2. Service Level Agreements, and
3. a transaction processing mechanism.

During the Implementation Phase the Project Team utilized the independent reviewer to monitor, review and make recommendations to enhance all implementation-related activities and to ensure compliance with the OEB Decision and ARC requirements.

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1 Introduction

Background

This *Report on Affiliate Transactions Regulatory Compliance: Methodology and Implementation* (”Report”) documents the response of Toronto Hydro-Electric System Limited (“THESL”) to the Decision with Reasons 3.2 and Direction 3 of the Ontario Energy Board EB-2005-0421 (“OEB Decision”) in the matter of the application by THESL for electricity distribution rates (“EDR”) for 2006. The OEB Decision is found at www.oeb.gov.on.ca/html/en/consumers/understanding/2006edr_decisions.htm.

Purpose and Objectives

The Report presents the methodologies utilized and steps undertaken by THESL to comply with the OEB Decision and additional steps undertaken to meet the requirements of the Affiliate Relationships Code for Electricity Distributors and Transmitters (“ARC”). The key objectives of the Report are to:

1. describe and explain the context of THESL’s and THC’s response and actions,
2. present and explain THESL’s methodological approach, studies and findings related to affiliate transactions, costing and transfer pricing,
3. compile or identify for reference purposes all material evidence related to the above initiatives,
4. provide a comprehensive body of materials and evidence for THESL Regulatory Affairs to use for the 2008-2010 EDR application.

Document Ownership

The Report was sponsored by JS Couillard, Chief Financial Officer.

External Advice and Support

Joel Singer of Singer & Watts Limited[1] provided key preparatory materials and advice on methodological approaches. R.J/ Rudden Associates, a unit of Enterprise Management Solutions Division, Black & Veatch Corporation[2] conducted the independent review of the methodology and its implementation. KeyWillow Consulting[3] supported project management, business analysis and data collection.

Shelf life

This Report is a valid representation of the methodological considerations and material steps undertaken by THESL in regard to compliance with ARC and the OEB Decision, as at June 30, 2007.

[1] Appendix 2 -Singer & Watts Limited
[2] Appendix 3 - R.J/ Rudden Associates, a unit of Enterprise Management Solutions Division, Black & Veatch Corporation
[3] Appendix 4 -KeyWillow Consulting

2 Background

2.1 Toronto Hydro Corporation

As of December 31, 2006 the Toronto Hydro Corporation ("THC") group of companies[4] had 1,673 employees and annual revenue of $2.247 billion. The City of Toronto ("City") is the sole shareholder of THC, the holding company of the following affiliates:

1. Toronto Hydro-Electric System Ltd ("THESL"): the regulated Local Distribution Company ("LDC"), serving 678,000 customers and representing approximately 95% of THC's revenues and assets,
2. Toronto Hydro Energy Services Inc ("TH Energy"): an unregulated company providing street lighting and expressway lighting services and development of energy efficiency products and services, and
3. Toronto Hydro Telecom Inc. ("Telecom"): an unregulated company providing fibre optic capacity and managing data communications services.

In order to promote uniformity of client service and maximize efficiencies of scale, THC and the affiliates maintain certain operations on a shared services model. THC and each affiliate pays for their use of each shared service. Beginning in 2006 THC initiated a number of changes to minimize the number of shared services and inter-affiliate transactions, to develop a high level of autonomy amongst affiliates, to provide for greater regulatory clarity and to allow for a higher degree of transparency. Several functions performed by THC were transferred to THESL and other unregulated affiliates reflecting the direct nature of the services performed.

2.2 Regulatory Context

The OEB regulates Ontario's electricity and natural gas sectors. Transactions between an electricity distributor or LDC and its affiliates are subject to the OEB's ARC. In the matter of this Report, the most pertinent elements of the ARC being considered include:

2.2 Sharing of Services and Resources

2.2.1 Where a utility shares services or resources with an affiliate it shall do so in accordance with a Services Agreement…(which) shall include:

(a) the type, quantity and quality of service;

(b) pricing mechanisms;

(c) cost allocation mechanisms;…

and,

2.3 Transfer Pricing

2.3.1 Where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value of the service, resource or product.

2.3.2 In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the fair market value. For the purpose of purchasing a service, resource or product a valid tendering process shall be evidence of fair market value.

2.3.3 Where fair market value is not available…a utility shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital…

[4] Appendix 5 –THC Business Organizational Structure

2.3 OEB Decision

The OEB decision of April 12, 2006, in the matter of THESL's 2006 application for electricity distribution rates, expressed concern about THESL's approach to shared services costs. As found in section 3.2 of the OEB Decision the Board's concerns include:

1. the lack of substantive evidentiary support for amounts recovered by THC from THESL,
2. the use by THC of solely non-time based allocators to determine amounts of shared services cost recovery from THESL, and
3. the use of relative revenue as a proxy for time allocation of shared services costs.

Other comments of interest include:

1. that actual time based shared cost allocation should be used whenever possible,
2. that "*allocator proxies*" should be used only as a last resort,
3. that efforts to track time within shared services should be "*relatively easy to implement*", and
4. the need for transparency.

The OEB directed THESL to develop "*a time-based shared services allocation methodology for non-direct corporate costs that incorporates the following elements;*

1. *time/cost tracking of individual efforts,*
2. *description of THESL's need for the service,*
3. *assessment protocol and allocation of non-time related expenses",* and

to provide*:*

"*a detailed report on the shared service allocation rationale and methodology (as) part of THESL's next rate application*."

2.4 OEB Compliance Office Inquiries

Subsequent to the OEB Decision, the OEB Compliance Office requested information from THC in regard to specific aspects of the services shared between THC, THESL and its affiliates[5]. The questions raised and the process of preparing responses provided additional direction and material for the consideration of THESL as it prepared a comprehensive response to the OEB Decision on rates. THC responded to the OEB Compliance office directly in separate correspondence[6].

2.5 THC and THESL Response

In response to the OEB Decision and subsequent OEB queries, THC and THESL undertook the following initiatives:

1. development of corporate-wide strategy with the primary goal of ensuring compliance with the OEB Decision,
2. assigning significant departmental level resources to guide the corporate response,
3. creation of a Steering Committee and a Project Team within Corporate Finance, under the direct executive sponsorship of the CFO, to develop and implement the corporate response, and
4. to broaden the scope of THESL's response to address all relevant ARC requirements related to the sharing of resources and transfer pricing of transactions between THESL and all affiliated companies.

[5] Appendix 6 –OEB Compliance Office letter to THESL
[6] Appendix 7 –THC Letter to OEB Compliance Office

The following additional control activities were implemented to ensure appropriate transfer pricing and compliance with ARC:

1. central management,
2. annual review of allocated services and resources,
3. management and executive approval,
4. periodic internal audit of allocated charges, and
5. periodic collection of relevant market data to validate transfer prices.

2.6 Shared Services Project, Steering Committee, Project Team[7]

A Steering Committee comprised of senior THC and THESL staff was established to provide strategic direction and leadership, and to ensure the project was successfully completed on time and within budget, that it met all of the in-scope requirements and that the benefits of the project were met.

The Project Team was comprised of staff from THC and THESL, and Joel Singer, a subject matter expert, in an advisory capacity. The Project Team developed a program to centrally manage and document allocated services and resources (Methodology – Phase I), and to ensure transfer pricing is appropriately charged and supported (Implementation – Phase II).

Phase I: Methodology

In order to establish product, resource and service costs, and a mechanism to allocate those costs to affiliates, the Project Team instituted a review and enhancement of source data, methodologies and business practices to:

1. create an inventory of affiliate company service transactions,
2. determine if services are required for THESL or affiliates
3. determine how to cost each service,
4. establish criteria for identifying potential fair market value comparisons for each service, where possible, and
5. prepare a method to fairly allocate the cost of services to affiliates.

An independent review[8] identified numerous useful enhancements, which were incorporated across the Methodology phase deliverables and into the subsequent Implementation phase.

Phase II: Implementation

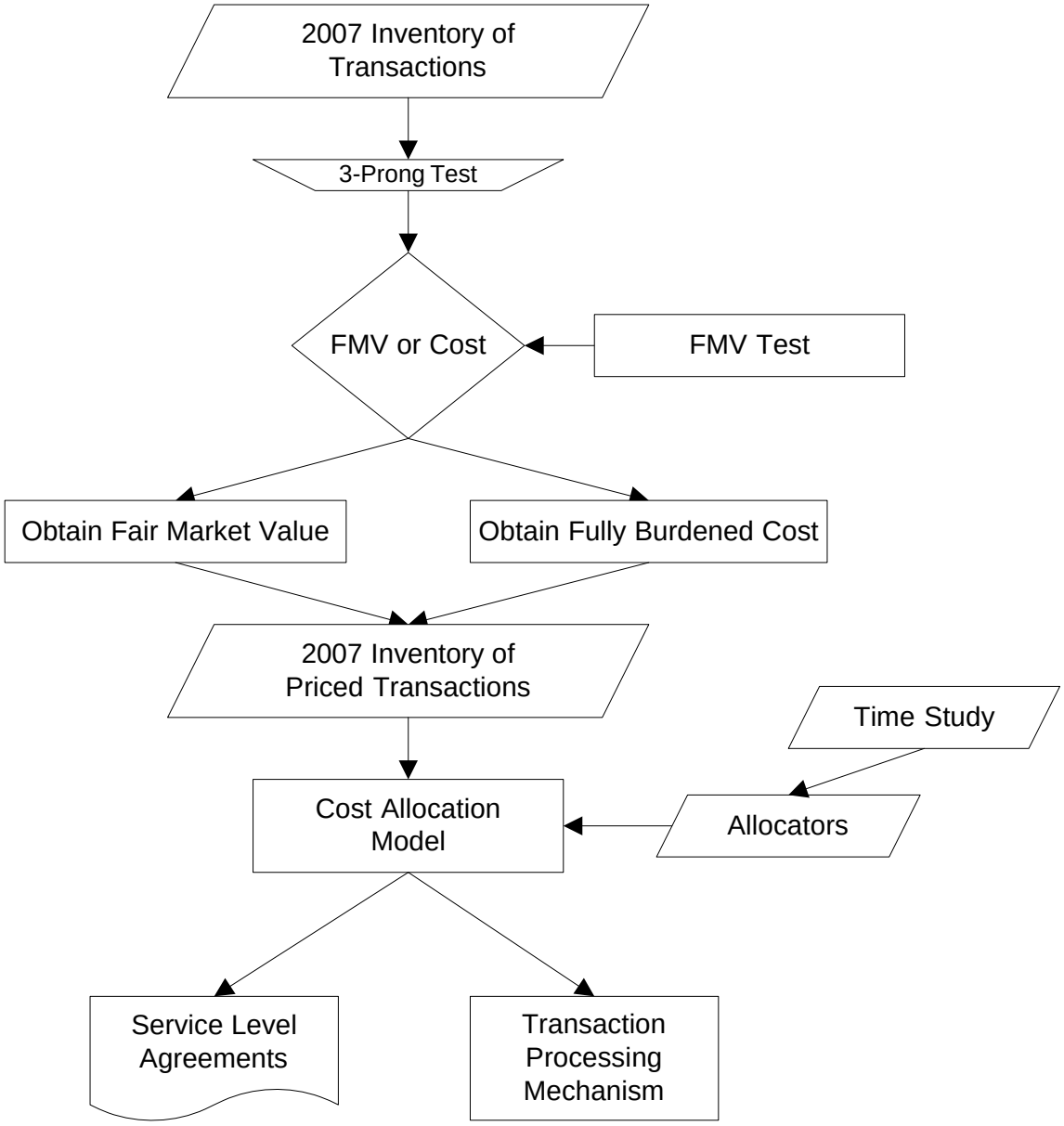
Building from the findings and deliverables of Phase I and the subsequent external review, the Project Team implemented the new methods and applied newly collected data in the preparation of:

1. 2007 transfer pricing,
2. Service Level Agreements ("SLA"), and
3. transaction processing mechanism.

During the Implementation Phase the Project Team utilized the independent reviewer to monitor, review and make recommendations to enhance all implementation-related activities and to ensure compliance with the OEB Decision and ARC requirements.

[7] Appendix 8 –Steering Committee and Project Team
[8] Appendix 15 –Related Documents: Independent Review

Shared Services Process Flow



3 Phase I: Methodology

3.1 Inventory of Shared Services and "Affiliate Transactions" [9]

3.1.1 Defining Affiliate Transactions

Transactions were defined to include:

1. services, resources or products provided by THESL to an affiliate, and
2. services, resources or products received by THESL from an affiliate,

3.1.2 Defining Data Requirements

Data elements within the inventory of transactions were derived from previous SLAs and detailed reviews from all business units. Additional categories of data to be collected were defined by ARC compliance requirements and include:

- Service Name and Definition: name and short description of service, resource or product
- Service Provider: company name, related Responsibility Centre ("RC") number and RC name
- Service Receiver: company name, related RC number and RC name
- Allocation Basis: time, unit or other price transfer allocator
- Quantity/Volume: dollar value or volume of service, resource or product
- Quality Measure: key performance indicators and any other significant determinant (e.g. regulatory and legislative requirements, timeliness, accuracy, etc.)
- Fully Burdened Cost: from 2007 budget, including depreciation and cost of capital
- FMV Applicability: yes or no
- FMV value: $ value at market price of service, resource or product

3.1.3 Capturing Service Transaction Data

Initial data was derived from existing SLAs between THESL and affiliates. Subsequently, financial system records were thoroughly examined to identify other transactions.

3.1.4 Internal Quality Assurance Process

Internal verification of data resulted, in part, from service *provider* transaction data being cross-checked against service *receiver* transaction data. Financial analysts were assigned to meet all business unit managers and senior executives to review affiliate transactions and to update transaction lists for any omissions or errors.

3.1.5 Executive Sign-Off

All transaction data was collated by business unit and submitted for review and sign-off to senior management. All senior executives attested to the accuracy and completeness of transactions involving their respective business units. This process also includes a review of the required services to ensure it provides value to THESL or the other affiliates. The CFO of THC and the Presidents of the affiliates also signed certificates on behalf of their respective organizations.

[9] Appendix 15 –Related Documents: Inventory of Transactions

3.1.6 Justification Test

The Project Team reviewed each transaction to determine whether or not they were related to the distribution of electricity. The OEB Three-Prong Test conducted by the Project Team was used to demonstrate that:

1. corporate centre charges were prudently incurred by, or on behalf of, the companies for the provision of services required by Ontario ratepayers,
2. corporate centre charges were allocated appropriately to the recipient companies based on the application of cost drives/allocation factors supported by principles of cost causality , and
3. the benefits to the company's Ontario ratepayers equal or exceed the costs.

3.2 Costing Framework

Following the development of the Inventory of Transactions, the Project Team defined parameters for the application of fair market value (FMV) and cost-based pricing (CBP).

3.2.1 Methodology, Implementation and Quality Assurance

In establishing the price of a transaction THESL followed the ARC protocol that requires the use of:

1. FMV pricing where available, and
2. CBP where FMV is not available.

3.2.2 Fully Burdened Cost

THESL initially determined the approximate cost of providing its service, resources and products at RC level provided in the 2007 budget. Costs were calculated, according to the ARC requirement, to include:

1. Direct operating costs[10]
2. Indirect operating costs
3. Capital costs[11]

[10] Appendix 9 -Direct and Indirect Operating Costs
[11] Appendix 10 -2006 Capital Cost Calculation

3.3 Fair Market Value

3.3.1 Determining Applicability of FMV

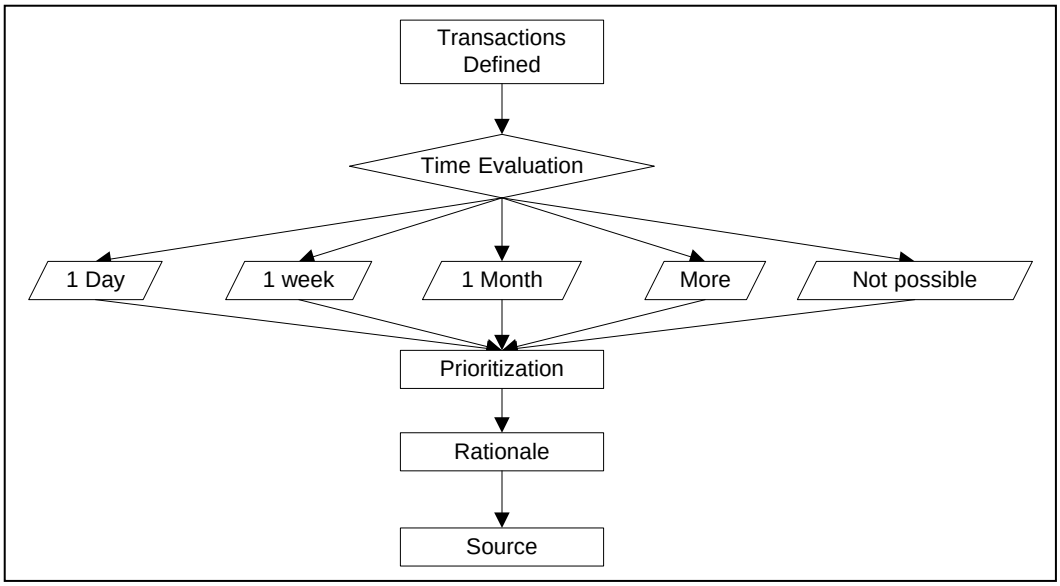
In determining whether or not FMV can be applied to a shared service transaction it is necessary to understand how the cost was incurred, establish whether or not a market for the service exists, determine whether or not a price can be found in the market place, and decide how long it might take to establish a price for the service.

Expert Panel

Private sector experts with experience in the sectors and services related to the shared services that occur within the THC group of companies were retained to assist in providing answers to these questions. A panel was convened to review each shared service transaction to determine whether or not FMV could be found. The panel was comprised of 4 senior purchasing and business support services experts from the private sector. The panel evaluation consisted of the following:

1. a review of the definition and data related to each transaction,
2. an evaluation of the length of time to find FMV for each transaction,
3. the prioritization of transactions by level of difficulty,
4. the provision of a rationale or specific comments, where required,
5. the provision of sources, where possible, for obtaining FMV, and
6. the identification of transactions where preparatory work for defining data would be a challenge.

A schematic representation of the process followed is shown below.



3.3.2 THESL FMV Business Analysis

The Steering Committee received the findings of the expert panel and further examined each transaction to consider whether other business factors might affect the panel's findings. The Steering Committee determined that FMV could not be found, or was not necessary to find, for those transactions where:

1. the OEB regulates pricing for most or all of the service,
2. the service will not be required in the long term,
3. service data is currently insufficient to successfully initiate an immediate search for FMV,
4. the cost and complexity of finding FMV is high, relative to the value of the service, and
5. other factors existed which mitigated against finding FMV (full details in *THC/THESL Business Analysis of the Findings of the Fair Market Value Expert Panel).*

3.4 Cost Allocation Method

With the availability of a fully revised Inventory of Transactions, actual costs and FMV applicability data, the Project Team developed a method to allocate service, resource and product prices related to the transactions taking place between THC, THESL and the affiliates. THESL commissioned Singer & Watts Limited to examine current approaches and key OEB decisions discussing cost allocation.

3.4.1 Sector and Regulatory Environment

Numerous approaches to cost allocation by energy utilities were considered including the Regulatory Cost Allocation Methodology ("RCAM") used by Enbridge Gas and the Rudden Methodology ("Rudden") utilized by Hydro One. A number of recent OEB decisions were considered relevant to THESL's considerations in this matter, including the OEB reports on Enbridge Gas, EB-2005-0001/EB-2005-0437 and RP-2002-0133, and its report on Hydro One, RP 1998-001[12].

The cost allocation methods of Enbridge Gas (by Deloitte) and Hydro One (by Rudden) were found to be of most relevance to THESL. The OEB decisions in each application were seen as useful elaborations on perceived deficiencies and strengths in the respective approaches, from which THESL could draw useful lessons in the development of its own approach to cost allocation. In addition, it was determined that any shared services arrangements must be structured in a way that recognizes the OEB's interpretation of the three-prong test. It was felt that the Rudden approach offered advantages for THESL as it is simpler and has achieved greater regulatory acceptance. Moreover, because Hydro One's structure with regard to subsidiaries and allocation issues is more similar to the structure of THESL than that of Enbridge, the Rudden approach was considered a better fit. However, it was determined by Singer that:

> "*…neither the Deloitte nor the Rudden study sufficiently defined the costs to be allocated. Deloitte presents no information about why some costs are classified as general expenses and others are called direct charges other than to say this is how Enbridge itself classifies them. Rudden provides little information about how the costs of functions that provide service to other departments are handled…. Moreover, neither Deloitte nor Rudden explains how capital items and return on invested capital are treated in the cost allocation process.*"[13]

As a result, THC and THESL decided to develop a cost allocation method that was derived from Rudden but that applied greater rigour in the definition of costs to be allocated and demonstrated that an appropriate portion of overall corporate costs were allocated to affiliates. In addition, because THESL would be relying on an internally developed cost allocation method, an independent review of the proposed methodology and its application was deemed essential to the cost allocation being accepted by the OEB in future regulatory reviews.

3.4.2 Methodology

The shared services found in the inventory of transactions and shared service prices are derived from the previously described CBP mechanism. For allocation purposes shared service costs are categorized by their inherent business function into those based on usage and those based on time. Usage-based shared service costs are further classified as job based or unit-based. In general, allocated charges are primarily time-based, but other allocators are used where appropriate.

[12] Appendix 11 -Cost Allocation: Methods and Regulator Decisions
[13] Appendix 12 -Cost Allocation: RCAM and Rudden

Usage Basis: Job

Used when a service relates to a specific field task with identifiable amounts for labour time, vehicle usage time and /or other spending incurred with third parties. Under this basis, the RC providing a service tracks each of these cost elements by charging the appropriate time and/or expenses to a specific work order in the corporation's Enterprise Resource Planning ("ERP") system. The resulting total cost is then charged to the affiliate receiving the service.

Usage Basis: Unit

Used when the service recipient can be identified as a specific RC but where job costing is not practical or feasible. One example would be support services provided by Information Technology as a service to a number of RCs. Unit prices are calculated such that, when applied to projected quantities, they will offset the service provider's expected total cost to provide the service. The total resulting charge to each affiliate depends on the actual quantity and mix of services consumed by the affiliate.

Time Basis

Used when there is no usage charge in effect. Each service provider was tasked to conduct a time study or deliver time study[14] estimates of the relative proportion of costs attributable to itself and each affiliate. In preparing these estimates, management within the service provider considered the expected time required from each staff member to deliver services to each affiliate.

Other Basis

In some cases, service providers undertake activities which are required by a number of affiliates but where the associated time spent on the activity cannot be distinguished by individual affiliate. One example would be the development of new THC group-wide human resource policies. In such cases the service provider reported the proportions of staff time relating to the activity and suggested an appropriate allocation basis that would result in a fair distribution of associated costs to each affiliate. For example, in determining the allocation for the development of THC group-wide human resource policies the headcount in each affiliate is the appropriate basis on which charges are allocated.

3.4.3 Time Study

A time study was conducted within THC of those shared services it was determined were appropriate to allocate by time. The time study was conducted over a period of three months with each service provider tracking actual time expended for each affiliate. Individual staff involved in the provision of shared services tracked their time on a daily basis. The cost proportions to each affiliate resulting from the time study will be applied to the service provider's overall budget costs to determine the allocated charge to each affiliate. At each year-end a review of the actual expenditures will be performed and any material adjustment will be allocated to each affiliate proportionately.

Also, service providers assumed certain costs other than employee compensation, in order to meet their service delivery requirements. Appropriate allocations for each of these costs are determined within the same process used to collect time study data.

[14] Appendix 13 -Time study internal memo and Appendix 14 -Time Study Template

3.4.4 Quality Assurance

The Project Team reviewed all allocations in order to:

1. determine the reasonableness of time-based % allocations,
2. assess appropriateness of suggested non time-based allocators, and
3. calculate the effective overall % of payroll costs charged to each affiliate

The methodology utilized, its implementation and the enhanced Inventory of Transactions were submitted for independent review, as described in the Independent Review section of this Report.

3.5 Phase I Outcome

At the conclusion of Phase I the Project Team had in place:

1. dollar values for the 2007 RC level costs of THC, THESL and affiliates shared services, resources and products,
2. an Expert Panel study that identified services for which FMV could be found,
3. an internal business analysis that supported the decision to find FMV for certain transactions,
4. a complete inventory of shared service transactions impacting THESL in 2007,
5. a costing framework,
6. a cost allocation methodology,
7. an independent review of the methodology, and
8. an electronic and hard-copy archive of all related supporting materials.

4 Phase II: Implementation

4.1 2007 Transfer Pricing

The external FMV expert panel determined (section 3.3.1) that FMV could be found in the market place for 60 of 72 transactions listed in the 2007 Inventory of Transactions. Through the subsequent THESL FMV business analysis (section 3.3.2) the Steering Committee determined that FMV would be found for 13 of the 60. The findings of the expert panel are found in the *Report of the Expert Panel on Fair Market Value.* The findings of the THESL FMV Business Analysis are found in the report *THC/THESL Business Analysis of the Findings of the Fair Market Value Expert Panel*

As at the time of the completion of this Report THESL had initiated a project to find FMV for certain transactions, slated for completion by the summer of 2007. FMV findings will be integrated into the SLA pricing schedules through the annual cost-allocation true up where applicable.

4.2 Cost Allocation

Services Provided by THESL

Costs for RC's within THESL that provide services to THC and affiliates are derived from prior period actuals. These costs are fully burdened with direct, indirect and capital costs. Each RC's costs are assessed to allocate costs to THC and affiliates based on specific drivers (usage, time or other). In most cases costs are directly attributable to usage.

Occupancy

Occupancy costs are allocated to the affiliates based on square footage utilized/occupied by the affiliates multiplied by the occupancy cost rate. All costs related to occupancy (e.g. rent, maintenance, property tax, etc.) for buildings owned and operated by THESL and management of Facilities (e.g. salaries of facilities personnel) reside in the department called Facilities located within THESL. To calculate the occupancy rate, the total expenditure before allocations reported in the Facilities department is used as the base. A return of capital and depreciation of real property assets is then added to that base[15]. The total figure is then divided by the total overall square footage to determine an occupancy rate per square footage. TH Energy and Telecom operate mainly from their own facilities. The THESL Facilities department does not manage their costs.

Fleet

Fleet cost allocation consists of specific and overhead charges. Specific charges are charges that have a direct correlation to usage (e.g. fuel, licensing, insurance and etc.). Overhead charges are all other costs which relate to the operation of the fleet department, including the allocated occupancy charge and IT charge. Also included in the overhead charge is the return on capital and amortization of the fleet assets. The overhead charge is then divided by the number of vehicles in the fleet, segregated by trucks and autos to determine an overhead rate for each type of vehicle.

Information Technology and Services

Costs are allocated based on end user usage of services/products such as workstations, desktops, laptops, network access and telephony. Costs include a return on capital and the allocated occupancy charge to determine the total unit costs, which is then multiplied by the number of users in each RC.

Services Provided by THC

Costs for RC's within THC that provide services to THESL, are derived from prior period actuals. Shared service cost allocations that THC receives from THESL (inclusive of direct, indirect and capital costs) are added to these native costs. The allocations received are allocated to THC RC's proportionate to each of THC RC's headcount. The sum of the native cost and the allocated cost yields each RC's total estimated cost for the year.

THC then isolates and quantifies costs directly attributable to itself, THESL and each affiliate. Cost allocators are identified and utilized to determine the actual direct cost of the services provided. The costs are fully burdened and in the case of payroll and other indirect support costs are apportioned according to the findings of the time study. Within each RC direct costs are subtracted from the RC's total cost, yielding the indirect costs. These indirect costs are allocated to THESL and the affiliates utilizing the ratios determined through the time study.

Residual costs within THC, those that are not directly or indirectly attributable to THESL or the affiliates, remain resident within THC as an entity cost.

[15] Appendix 10 –2007 Capital Cost Calculation

4.3 Service Level Agreements

As mandated by the ARC, service level agreements were developed to manage inter-affiliate shared services. These agreements include a legal contract with an appendix that lists the services covered by the agreement. The agreements were constructing using information drawn from the Phase I deliverables. This included the name, description, type, quantity and quality of service for each shared service transaction, the pricing mechanism (FMV or CBP) and the cost allocation mechanism.

4.4 Transaction Processing Mechanisms

For shared services governed by an SLA THESL bills each affiliate based on the total annual shared service budget, divided by usage, by month. This amount is charged monthly to each affiliate. For services rendered on a usage basis affiliates are charged on a per use basis.

Appendices

1. Acronyms

ARC	Affiliate Relationships Code for Electricity Distributors and Transmitters
CBP	cost-based price
EDR	electricity distribution rate
ERP	enterprise resource planning
FMV	fair market value
LDC	local distribution company
OEB	Ontario Energy Board
OEB Decision	Ontario Energy Board EB-2005-0421 Decision with Reasons
PILs	payment in lieu of taxes
RC	responsibility centre, a THESL or affiliate company business unit
RCAM	regulatory cost allocation model
ROE	return on equity
SLA	**s**ervice level agreement
THC	Toronto Hydro Corporation
TH Energy	Toronto Hydro Energy Services Incorporated, includes Toronto Hydro Street Lighting Incorporated as of September 1, 2006
THESL	Toronto Hydro-Electric System Limited
Telecom	Toronto Hydro Telecom Incorporated

2. Singer & Watts Limited

Singer & Watts provides expert management consulting services to utilities and other corporations across the United States and Canada. The firm has four main practice areas:

- Pricing and Marketing,
- Regulatory Affairs,
- Public Affairs and Communication, and
- Management Support.

Joel Singer, B.S., M.A. and J.D.
Partner
Shared Services Project Team Member and Regulatory Affairs Analyst

3. R.J/ Rudden Associates, a unit of Enterprise Management Solutions Division, Black & Veatch Corporation

R.J/ Rudden Associates, a unit of Enterprise Management Solutions Division, Black & Veatch Corporation. is a strategic, economic and management consulting firm specializing in energy and utility matters.

Richard. J. Rudden
Senior Vice President
Shared Services Project Auditor

Howard S. Gorman
Principal Consultant
Shared Services Project Auditor

Robert O'Brien
Principal Consultant
Shared Services Project Auditor

4. KeyWillow Consulting

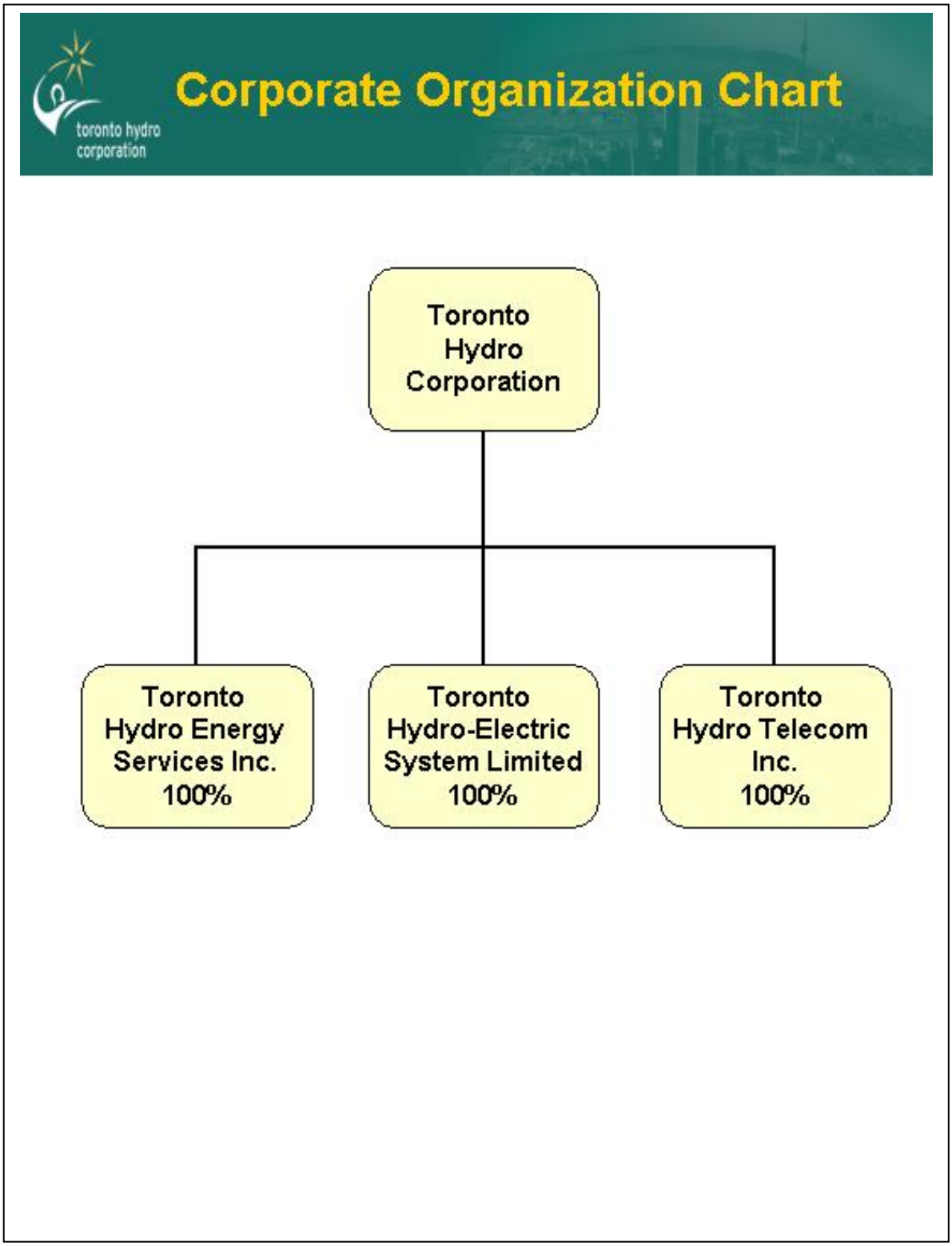
KeyWillow Consulting provides contracted and subcontracted business support services across North America to many sectors, including energy. The firm has provided study and report development services to many organizations across a range of industries.

Chris Anstead, Ph.D.
Managing Director
Shared Services Lead Analyst

Robert Brukner, M.A.
Senior Consultant
Shared Services Project Management Support

Vaishali N. Agarwal, MBA
Consultant
Shared Services Analyst

5. Toronto Hydro Corporation Organizational Structure



6. OEB Compliance Office Letter to THESL

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th. Floor
Toronto ON M4P 1E4
Telephone: (416) 481-1967
Facsimile: (416) 440-7656

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4
Téléphone; (416) 481-1967
Télécopieur: (416) 440-7656

Ontario

Compliance Office

April 17, 2006

File No.: MI20051255

Mr. Richard Zebrowski
Toronto Hydro-Electric System Limited
Vice President, Regulatory Services
14 Carlton Street
Toronto, Ontario
M5B 1K5

TORONTO HYDRO
13h36
APR 20 2005
Rick Zebrowski
Vice President, Regulatory Services

copy: RZ
CR

Re: <u>Distributor Services to Affiliates</u>

<u>Compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters and section 71 of the *Ontario Energy Board Act, 1998.*</u>

Dear Mr. Zebrowski:

As you may be aware, compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters (the "ARC") is a priority for the Compliance Office under the Annual Compliance Plan. In that regard we have reviewed material relating to Toronto Hydro Electric System Limited's (THESL) affiliate relationships based on a number of allegations and the rate case filing. This review has raised some issues regarding THESL's compliance with the ARC and with section 71(1) of the *Ontario Energy Board Act, 1998* (the "*Act*"). In order to address these issues, I request that you provide the following information.

<u>Distributor Management and Control</u>

1. Of the individuals listed on the attached chart, please indicate which individuals, if any:

   a) are employed directly by THESL;

   b) are employees of THESL and also officers of an affiliate and please identify the affiliate;

   c) are officers of THESL, but employed by an affiliate and please identify the affiliate; or,

d) provide services to both THESL and another affiliate. Please identify the affiliate(s) and describe the services the individual provides to THESL, and to the affiliate(s).

2. Please indicate whether Mr. Peter D'Uva is an employee and/or officer of THESL, in addition to being the President of Toronto Hydro Street Lighting Inc. ("TH Street Lighting"). If so, please explain Mr. D'Uva's responsibilities at THESL.

Employee Sharing and Physical Separation

The services agreements filed in response to VECC interrogatory #8, appear to indicate that THESL staff are providing services that support its affiliate's non-regulated activities.

A - Toronto Hydro Energy Services Inc. ("TH Energy Services")

Testimony given by Mr. Haines on January 17, 2006, and Ms. Davidson on January 31, 2006, indicated that THESL provides TH Energy Services with staff who complete water heater field servicing work and customer call centre services. Ms. Davidson's testimony also indicated that the installation and replacement of water heaters was outsourced to a third party. However, the October 2001, service level agreement for water heater services between THESL and Energy Services states that THESL will provide TH Energy Services with field services that include repair, installation and removal services.

3. Please provide an up to date and complete description of the field services work relating to hot water heaters that THESL staff provides to TH Energy Services.

4. Please provide an up to date and complete description of the customer call centre services relating to hot water heaters that THESL provides to TH Energy Services.

5. Please provide a complete description of any other THESL staff and resources that are used by TH Energy Services to provide its other (non-hot water heater) related businesses.

6. In regards to the above mentioned services that THESL provides to TH Energy Services, please explain how the provision of such services complies with section 71(1) of the *Act* and the restriction on the business activities of a distributor.

B - Toronto Hydro Street Lighting Inc. ("TH Street Lighting")

The January 2005 services agreement between THESL and TH Street Lighting indicates that THESL provides TH Street Lighting with services which include construction, emergency response and customer services.

7. Please confirm that THESL provides TH Street Lighting with staff and resources to complete construction, emergency response, and call centre services.

8. Please provide a detailed description of the services provided by THESL to TH Street Lighting for the provision of construction, emergency response and call centre services.

9. TH Street Lighting offers to supply and install private sentinel lighting. Please provide a description of any THESL staff and resources that are used by TH Street Lighting to provide these services.

10. Please provide a copy of the services agreement, including all fees and charges, that outlines the provision of services, as well as, the relationship between THESL and TH Street Lighting for the attachment of streetlight equipment to THESL owned assets.

11. In regards to the above mentioned services that THESL provides to TH Street Lighting, please explain how the provision of such services complies with section 71(1) of the *Act* and the restriction on the business activities of a distributor.

C - General Affiliate Issues

12. Please indicate and provide details as to whether any THESL employees who are involved in collecting, or have access to, confidential information (as defined in the ARC) provided services to any affiliate.

13. Please indicate and provide details as to whether any THESL employees who are involved in the day-to-day operation of the distribution network provided services to any affiliate.

14. Please provide the contact address, phone number and fax number for each affiliate.

15. In regards to the above mentioned services that THESL provides to its affiliates, please explain how the provision of such services complies with section 71(1) of the *Act* and the restriction on the business activities of a distributor.

<u>Shared Corporate Services</u>

The services agreements filed in response to VECC interrogatory #8 provide a brief overview of the various shared corporate services that THESL provides to its affiliates. Please provide the following information about the provision of these services.

16. Please provide a detailed description of the actual work performed by THESL staff when providing the following services to its affiliates:

I. Facilities & Services;
II. Fleet Services;
III. Information Technology & Services; and
IV. Procurement.

17. Please describe the difference between the Information Technology services that THESL purchases from the Toronto Hydro Corporation and the Information Technology services that THESL sells to affiliates.

18. In addition to the above mentioned shared corporate services, please provide a description of any other services that THESL provides to Toronto Hydro Telecom Inc. ("TH Telecom")

19. In addition to the above mentioned shared corporate services, please provide a description of any other services that THESL provides to Toronto Hydro Corporation.

Transfer Pricing

Testimony given by Mr. Couillard on January 20, 2006, indicated that the services agreements and associated transfer prices between THESL and its affiliates were not negotiated as "arms length" transactions. The testimony also indicated that the transfer prices were cost based.

The ARC requires that a distributor provide a service to an affiliate at a sale price of no less than fair market value. Where a fair market value is not available, a distributor may use a cost-based price. In order to understand how the transfer prices for services THESL provides to its affiliates were established, please provide the following information.

20. For each of the services that THESL sells to its affiliates, please describe the mechanism used to establish the transfer price.

21. Please present the evidence that supports the fact that the THESL is charging no less than fair market value for the provisions of these services to its affiliates.

22. If transfer prices are cost-based, please describe the process that THESL used to determine that a fair market value was not available for each service, resource or product.

23. If the transfer prices are cost-based, please explain whether the prices charged by THESL are based on fully allocated costs (ie: comprised of all direct and indirect expenses plus a return on capital) or only direct costs.

Telecom Issues

Staff note that Telecom has recently announced plans to provide blanket "Wi Fi" internet access to the City of Toronto. In order to better understand the relationship between THESL and Telecom, please provide the following information.

24. Please clarify whether Telecom will be attaching radio access points for delivery of the "Wi Fi" network on any of THESL's assets.

25. If Telecom will be attaching equipment associated with this "Wi Fi" network onto THESL assets, please describe the methodology that will be used to establish the transfer price for the attachments.

26. Please provide a description of the services, if any, that THESL currently purchases from Telecom.

27. If THESL purchases services from Telecom, please provide a copy of the services agreement as required by the ARC.

28. Please outline details regarding THESL expectations for using the "Wi Fi" network (ie: smart metering) and how THESL and/or Telecom intend to determine the transfer price for these services.

I request* that you respond to these questions by May 2, 2006. If you have any questions or concerns with this request, please contact me directly at (416) 440-7724. Thank you for your cooperation in this matter.

Yours truly,

Paul Gasparatto

Paul Gasparatto
Project Advisor
Compliance Office

Attach.

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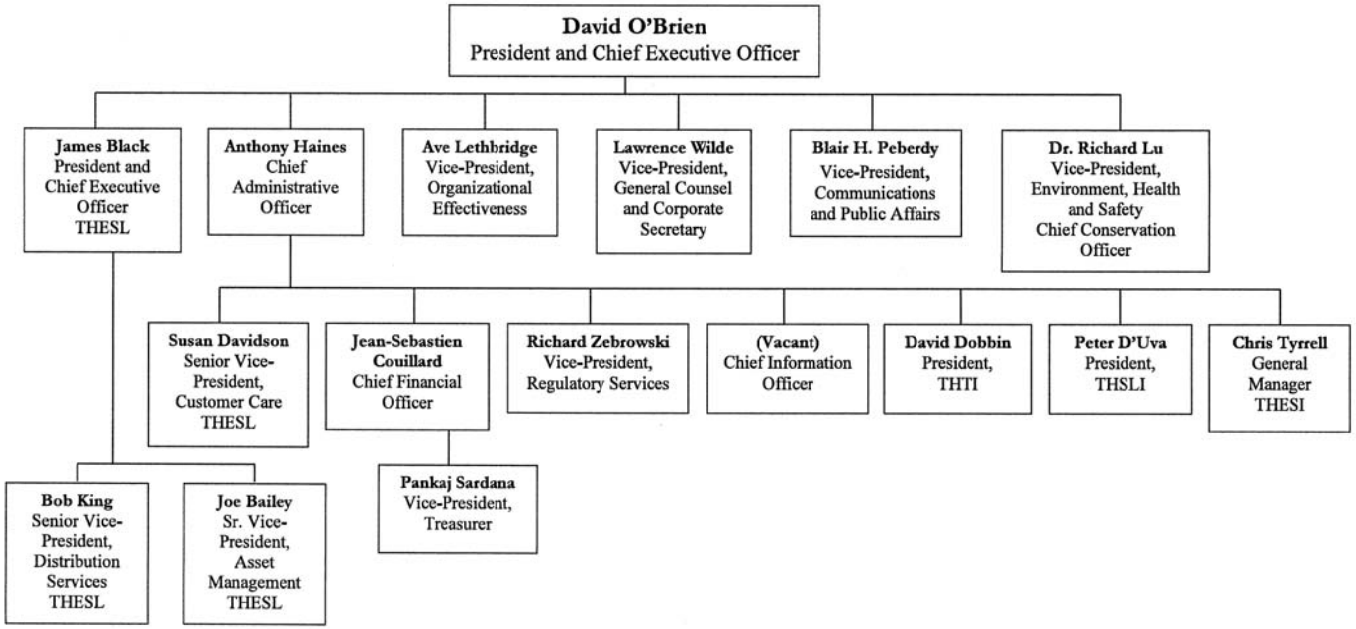
* As a Board appointed Inspector, I am collecting this information under the express authority of Section 107 of the *Ontario Energy Board Act, 1998*. Pursuant to Section 4.14 of the *Act*, the Board may collect personal information for the purposes of carrying out its duties and exercising its powers under this *Act* or any other *Act*.

VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES

Interrogatory 7

TORONTO HYDRO GROUP OF COMPANIES



7. THC letter to OEB Compliance Office

14 Carlton Street
Toronto, Ontario
M5B 1K5

Telephone: 416.542.2572
Facsimile: 416.542.2776
rzebrowski@torontohydro.com

toronto hydro corporation

May 24, 2006

VIA FACSIMILE – original to follow by mail

Paul Gasparatto, Project Advisor
Compliance Office
Ontario Energy Board
PO Box 2319
2300 Yonge Street, Suite 2700
Toronto, ON M4P 1E4

Dear Mr. Gasparatto:

Re: Distribution Services to Affiliates - Compliance with the Affiliate Relationships Code for Electricity Distributors and Transmitters and Section 71 of the *Ontario Energy Board Act, 1998* OEB File No. MI20051255

I write on behalf of Toronto Hydro-Electric System Limited (THESL) in response to your letter to me dated April 17, 2006 and further to my initial reply dated April 25. Responses to your questions have been provided in *italics*. Before responding to your questions, I have two comments:

- While we are pleased to discuss these matters with you and provide the information requested in your questions, we must insist that this information remain strictly confidential. You have requested this information in your capacity as an "inspector", a position established by Part VII of the *Ontario Energy Board Act, 1998* (the "OEBA"). Section 111 of the OEBA is clear in that all documents and records obtained by an inspector under section 107 or 108, and information obtained by an inspector under section 107 (this includes documents, records and information relating to transactions between licensed distributors and their affiliates), are confidential and shall not be disclosed to any person other than a member of the Board or an employee of the Board except in very limited circumstances – specifically "(a) as may be required in connection with the administration of this Act or any other Act that gives powers or duties to the Board or in any proceeding under this or any other Act that gives powers or duties to the Board; (b) to counsel

for the Board or an employee of the Board; or (c) with the consent of the owner of the document or record or the person who provided the information." THESL does not consent to the release of any documents, records and/or information relating to the matters that are the subject of your letter. Please confirm that any documents, records and information being provided to you in this matter will be kept in confidence in accordance with these provisions of the OEBA.

- During the OEB's hearing with respect to THESL's 2006 electricity distribution rate application, Mr. David O'Brien, President of Toronto Hydro Corporation, the parent corporation of THESL, discussed the organizational structure of the THC family of companies. Specifically, Mr. O'Brien discussed (see RP-2005-0020/EB-2005-0421, Transcript Volume 2, at pp. 10-12) the transition of activities from Mr. Black, the current President of THESL who is retiring this year, to Mr. Haines, currently the Chief Administrative Officer of THC. Mr. O'Brien advised the OEB that once this transition is complete, over the next year, the functions identified in the THC family's organizational chart as being carried out by particular members may change, and that some of the "shared-service functions" may end up in THESL. The reasons for this review are explained in the testimony. The review will also take the OEB's Decision on the THESL 2006 EDR application into consideration. It is therefore important to keep in mind, in considering the responses below, that the structure of THESL, and the THC family of companies generally, is in transition, and the organization's structure may be quite different within the next 12-18 months. Accordingly, these responses should be considered as subject to change.

<u>Distributor Management and Control</u>

1. Of the individuals listed on the attached chart, please indicate which individuals, if any:
   (a) are employed directly by THESL;
   James Black, Susan Davidson, Peter D'Uva, Bob King, Joe Bailey

   (b) are employees of THESL and also officers of an affiliate and please identify the affiliate;
   James Black, Toronto Hydro Corporation Executive Vice President; and Peter D'Uva, President, Toronto Hydro Street Lighting Inc.

(c) are officers of THESL, but employed by an affiliate and please identify the affiliate;
Lawrence Wilde, Toronto Hydro Corporation;
Jean Sebastien Couillard, Toronto Hydro Corporation;
Richard Zebrowski, Toronto Hydro Corporation; and
Pankaj Sardana, Toronto Hydro Corporation.

or,

(d) provide services to both THESL and another affiliate. Please identify the affiliate(s) and describe the services the individual provides to THESL, and to the affiliate(s).

Lawrence Wilde	*- legal services to all affiliates*
Ave Lethbridge	*- organizational effectiveness (including human resources) services to all affiliates*
Jean-Sebastien Couillard	*- financial services to all affiliates*
Pankaj Sardana	*- treasury services to all affiliates* *- electricity rate services to THESL*
Eduardo Bresani (CIO)	*- information technology services to all affiliates*
Richard Zebrowski	*- regulatory services to THESL and Toronto Hydro Energy Services Inc.* *- executive services as a member of TH Executive team to Toronto Hydro Corporation*
Richard Lü	*- health, safety and environmental services to all affiliates* *- conservation and demand management services to THESL*
David O'Brien	*- strategy, policy and stakeholder relations services to all affiliates and senior executive services to*

	various departments of Toronto Hydro Corporation
Anthony Haines	*- senior executive services to customer care sector of THESL, Toronto Hydro Telecom Inc., Toronto Hydro Energy Services Inc., Toronto Hydro Streetlighting Inc. and to information technology, regulatory and finance sectors of Toronto Hydro Corporation*
Peter D'Uva	*- see response to question #2, below*

2. Please indicate whether Mr. Peter D'Uva is an employee and/or officer of THESL, in addition to being the President of Toronto Hydro Street Lighting Inc. ("TH Street Lighting"). If so, please explain Mr. D'Uva's responsibilities at THESL.

   Peter D'Uva is employed by, but is not an officer of, THESL. At THESL, Mr. D'Uva has executive responsibility for the Meter Services Department and for ensuring the implementation of the Smart Meter program.

<u>Employee Sharing and Physical Separation</u>

3. Please provide an up to date and complete description of the field services work relating to hot water heaters that THESL staff provides to TH Energy Services.

   Pursuant to a Service Level Agreement, THESL provides installation, repair, maintenance and administrative services.

4. Please provide an up to date and complete description of the customer call centre services relating to hot water heaters that THESL provides to TH Energy Services.

   Pursuant to a Service Level Agreement, THESL supplies call centre services that relate to water heater billing inquiries and water heater service and tank installations. THESL Customer Service Dispatchers issue service orders for the required work and dispatch field staff for action.

5. Please provide a complete description of any other THESL staff and resources that are used by TH Energy Services to provide its other (non-hot water heater) related businesses.

THESL does not provide TH Energy Services with staff or resources. However, THESL provides, pursuant to a Service Agreement as required in the Retail Settlement Code, distributor consolidated billing (DCB) services to TH Energy Services. These services are provided to all electricity retailers that have signed Services Agreements with THESL and have requested DCB services.

6. In regards to the above mentioned services that THESL provides to TH Energy Services, please explain how the provision of such services complies with Section 71(1) of the *Act* and the restriction on the business activities of a distributor.

Section 71of the Act provides that a distributor, except through an affiliate or affiliates, shall not carry on any business activity other than distributing electricity. However, Section 73 makes it clear that the wording of Section 71 is intended to allow the distributor to provide services, including the use of its assets, to its affiliate. For example, Section 73 permits an affiliate to carry on business activities the principal purpose of which is to use more effectively the assets of the distributor. The Affiliate Relationships Code clearly contemplates that, as part of distributing electricity, the distributor will provide services to affiliates since it expressly permits a distributor to provide services to an affiliate.

7. Please confirm that THESL provides TH Street Lighting with staff and resources to complete construction, emergency response, and call centre services.

THESL does not provide TH Street Lighting Inc. with staff or resources. Pursuant to a Service Level Agreement,THESL does, however, provide TH Street Lighting with construction, emergency response and Call Centre services.

8. Please provide a detailed description of the services provided by THESL to TH Street Lighting for the provision of construction, emergency response and call centre services.

Construction services: install fixtures and brackets when conducting LDC-initiated construction work

Emergency response services: respond to emergency situations (e.g. street light pole hit) to ensure public safety and security by making site safe for the public

Call Center services: receive and direct calls related to street and expressway lighting and dispatch call if emergency related

9. TH Street Lighting offers to supply and install private sentinel lighting. Please provide a description of any THESL staff and resources that are used by TH Street Lighting to provide these services.

THSLI does not use staff or resources from THESL to provide these services.

10. Please provide a copy of the services agreement, including all fees and charges, that outlines the provision of services, as well as, the relationship between THESL and TH Street Lighting for the attachment of streetlight equipment to THESL owned assets.

Currently, THESL and TH Street Lighting do not have a services agreement for the attachment of streetlight equipment to THESL-owned assets.

11. In regards to the above mentioned services that THESL provides to TH Street Lighting, please explain how the provision of such services complies with Section 71(1) of the *Act* and the restriction on the business activities of a distributor.

See response to question #6.

12. Please indicate and provide details as to whether any THESL employees who are involved in collecting, or have access to, confidential information (as defined in the ARC) provided services to any affiliate.

THESL Customer Services management team and other THESL Customer Services staff in the following job positions perform work for TH Energy Services and TH Street Lighting: Customer Service Representative, Billing and Remittance Clerk, Customer Service Dispatcher, Field Service Representative, Field Service Clerk. Services are provided in accordance with THESL's Service Level Agreements with TH Energy Services and TH Street Lighting and relate to Rental Water Heaters and street lighting trouble reporting respectively. See also response to #5.
THESL managers and staff in each of these areas have received ARC training, including their responsibilities to maintain confidentiality in accordance therewith, and managers provide a written certification of compliance annually.

13. Please indicate and provide details as to whether any THESL employees who are involved in the day-to-day operation of the distribution network provided services to any affiliate.

THESL Power System Controllers and Trouble Dispatch and Trouble System Crews provide services to TH Street Lighting pursuant to Service Level Agreements.

14. Please provide the contact address, phone number and fax number for each affiliate.

THESL Affiliate	***Address***	***Phone Number***	***Fax Number***
TH Corporation	*14 Carlton Street*	*416.542.3000*	*416.542.2676*
TH Energy Services	*14 Carlton Street 4th Floor*	*416.382.6540*	*416.542.2640*
TH Telecom	*185 The West Mall Suite 500*	*416.599.3282*	*416.542.2665*
TH Street Lighting	*500 Commissioners Street*	*416.542.3195*	*416.542.2550*
1455948 Ontario Inc.	*14 Carlton Street*	*416.542.3000*	*416.542.2676*

15. In regards to the above mentioned services that THESL provides to its affiliates, please explain how the provision of such services complies with Section 71(1) of the *Act* and the restriction on the business activities of a distributor.

See response to question #6.

16. Please provide a detailed description of the actual work performed by THESL staff when providing the following services to its affiliates:
(a) Facilities & Services;
Operations & Maintenance; Real Estate; Human & Environmental Factors; Planning & Project Management; Facilities Management; Quality Assessment & Innovation; Investment Recovery; Infrastructure Occupancy Management; Wireless Business Solution Plan; Administration.

(b) Fleet Services;
Fleet Maintenance & Repair; Washing of Vehicles and Equipment; Fleet Vehicle & Equipment Asset Management; Inventory Management; Fuel & Lubricating Oils Management; Legislative Compliance; Licences, Permits; Fleet Parking; Driver Training & Licence Management; Centralized Tool Crib Service.

(c) Information Technology & Services;
There is no Information Technology and Services staff in THESL. Please see response to question #17 for further explanation.

and

(d) Procurement
Acquisition of Goods & Services; Contract Administration; Warehousing of Goods; Investment Recovery.

17. Please describe the difference between the Information Technology services that THESL purchases from the Toronto Hydro Corporation and the Information Technology services that THESL sells to affiliates.

Under the existing structure, all Information Technology ("I.T.") operations and staff reside within Toronto Hydro Corporation ("THC") while THESL maintains ownership of I.T. assets (e.g. hardware, software). The services THESL purchases from THC include 100% of I.T.'s operational and capital investment activities (e.g. governance, procurement, systems delivery, operations, support, management services). A more detailed description of these services can be found at Tab 6, section 6.2.3 of THESL's 2006 EDR application, RP-2005-0020 / EB-2005-0421.

THESL capitalizes a portion of these costs and sells portions of the non-capitalized services to affiliates based on each entity's usage (see response to question #20).

This arrangement results from the fact that THC cannot contract directly with affiliates to deliver I.T. services in a services agreement, since it does not own the underlying assets. THESL intends to review this arrangement as part of its ongoing review of affiliate transactions.

18. In addition to the above mentioned shared corporate services, please provide a description of any other services that THESL provides to Toronto Hydro Telecom Inc. ("TH Telecom").

THESL provides services to TH Telecom pursuant to pole attachment and duct rental agreements similar to agreements with Bell, Rogers and others.

19. In addition to the above mentioned shared corporate services, please provide a description of any other services that THESL provides to Toronto Hydro Corporation.

There are no other services provided by THESL to Toronto Hydro Corporation.

Transfer Pricing

20. For each of the services that THESL sells to its affiliates, please describe the mechanism used to establish the transfer price.

Transfer prices are established as part of the service providers' budget for the following year. There are two types of mechanisms, both cost-based: usage charges and allocated charges.

Service	***Usage Charges***	***Allocated Charges***
Information Technology *- desktop, network access and telephony* *- other*	*x*	 *x*
Facilities	*x*	
Fleet	*x*	
Procurement *- warehoused materials* *- other*	*x*	 *x*
Construction	*x*	
Emergency response	*x*	
Call Centre	*x*	

Water Heater	*x*	
Pole attachments & duct space rentals	*x*	
Laboratory	*x*	
Wireless	*x*	

21. Please present the evidence that supports the fact that THESL is charging no less than fair market value for the provisions of these services to its affiliates.

At this time, THESL has not concluded whether fair market values may be available for any of the services delivered to affiliates. These determinations form a key element in THESL's ongoing review of affiliate transactions.

To the best of THESL's knowledge, the cost-based allocations and usage charges currently in effect do not result in transfer prices that are below available fair market value.

22. If transfer prices are cost-based, please describe the process that THESL used to determine that a fair market value was not available for each service, resource or product.

See response to #21.

23. If the transfer prices are cost-based, please explain whether the prices charged by THESL are based on fully allocated costs (ie: comprised of all direct and indirect expenses plus a return on capital) or only direct costs.

Transfer prices include all direct and significant indirect expenses (i.e. Facilities, Vehicles, IT & Telephony). The return on capital was only explicitly considered in the case of pole attachment and duct space rental sold to the Telecom affiliate. As part of the ongoing review of affiliate transactions, THESL will determine whether a return on capital should apply to any other services delivered to affiliates.

Labour: *Payroll costs are fully burdened for non-wage benefits, including OMERS pensions, insurance benefits and accruals for post-employment benefits. An additional 'labour' burden also applies: hourly labour rates are calculated based on the fully burdened payroll cost divided by the number of hours available for work (e.g. excluding hours paid for holidays, vacation, sick time, safety meetings, inclement weather, etc.). Separate rates apply to overtime hours worked to reflect the premium payable in these circumstances.*

Other: *Each service provider considers all other expenses (e.g. costs incurred with vendors, usage charges) in determining the costs it must recover through transfer pricing. Vehicle depreciation expense is factored into the costs to be recovered through vehicle rates for Fleet services.*

Telecom Issues

24. Please clarify whether Telecom will be attaching radio access point for delivery of the "Wi Fi" network on any of THESL's assets.

THESL has received no such request.

25. If Telecom will be attaching equipment associated with this "Wi Fi" network onto THESL assets, please describe the methodology that will be used to establish the transfer price for the attachments.

Not Applicable. (See response to #24).

26. Please provide a description of the services, if any, that THESL currently purchases from Telecom.

THESL does not purchase any services from Telecom.

27. If THESL purchases services from Telecom, please provide a copy of the services agreement as required by the ARC.

Not Applicable. (See response to #26).

28. Please outline details regarding THESL expectations for using the "Wi Fi" network (ie: smart metering) and how THESL and/or Telecom intend to determine the transfer price for these services.

While plans for smart meters are still in a state of flux pending decisions from the provincial government, consideration is being given to using wireless technology to read smart meters. If such considerations are actualized as part of an arrangement between THESL and Telecom, any pricing would be done in a manner consistent with the Affiliate Relationships Code.

THESL would welcome the opportunity to discuss these matters with you further, in person. Arrangements to do so may be made by contacting the undersigned.

Yours truly,

R. Zebrowski, Vice-President
Regulatory Services
:car
/attach.

STRICTLY PRIVATE AND CONFIDENTIAL

page 13

8. Steering Committee and Project Team

Steering Committee

JS Couillard, CA
Steering Committee Chair
Chief Financial Officer, THC

David Powell
Manager, Project Support Office
Organizational Effectiveness, THC

Ann Grant, CMA
Acting Corporate Controller, THC

Asheef Jamal, CGA
Controller, THESL

Pankaj Sardana, CFA
Vice-President
Treasury, Regulatory and Rates, THESL

Lawrence Wilde, L.LB
Vice-President, Legal Services
General Counsel and Corporate Secretary, THC

Project Team

Ann Grant, CMA
Corporate Controller
Shared Services Project Manager
Corporate Accounting, THC

Danny Benwell
Director
Insurance and Risk Management, THESL

Sydney Carter
Project Analyst
Organizational Effectiveness, THC

Isabella Chung
Senior Finance Analyst
Finance, THESL

Raymond Tiam-Fook, CA
Senior Finance Analyst
Corporate Accounting, THC

Ivan Yu, CA
Manager
Financial Planning, THESL

9. Direct and Indirect Operating Costs

Direct Operating Costs

Under its responsibility accounting approach all costs incurred in THESL or its affiliates are charged to an RC with a manager accountable for actual results and variances to budget. These costs include:

- Payroll: salaries/wages, overtimes, premiums, pensions, other benefits, bonuses and payroll taxes
- Labour: time charged to RC work orders, net of labour costs recovered by RC staff
- Vehicle: fuel, repairs, licensing, insurance, vehicle use charged to RC work orders, net of vehicle costs recovered by RC vehicles
- Materials and services: inventory materials, consumables, external/contract services
- Support: utilities/telecommunications, office supplies/postage, employee expenses, rentals/leases, and other operating expenses, such as; insurance, foreign exchange and inventory adjustments, accretion of asset retirement obligations, bad debt, OEB fees and industry association fees.
- Taxes: property taxes, provincial capital tax (not reflected as income taxes).

Indirect Operating Costs

These are taken to include costs incurred by a RC other than the one providing a service, which have a quantifiable impact on the overall costs of providing the service.

- IT usage: use of PC and workstations including desktop support, data network access, email, internet, telephony
- Occupancy: rental charge for use of office or other work space, including all facility support services
- Fleet: monthly lease charge for dedicated vehicle usage

10. 2006 Capital Cost Calculation

These costs are incurred to fund assets used in providing services:

- Depreciation: straight-line depreciation of original asset cost, in accordance with standard depreciation rates based on the estimated useful life of the asset
- Return on Capital: Net book value of the asset multiplied by the regulated utility's approved pre-tax weighted average cost of capital.

Return on Capital Calculation

Net book value is defined as the average of the opening and ending balances for the fiscal year.

The utility's approved pre-tax weighted average cost of capital reflects its approved return on equity (ROE) and the weighted average cost of debt. The components are weighted based on the approved deemed capital structure (65% debt, 35% equity) and are calculated as follows:

ROE
The utilities approved ROE of 9% is divided by one minus the combined (federal and provincial) tax rate of 36.12% to reflect a pre-tax basis resulting in a pre-tax ROE of 14.1%.

Weighted Average Cost of Debt
Based on the allowed interest rates for the utilities debt financing:

Debt Amount (in millions)	Rate	Annual Interest
$980.2	5.00%	$49.0
$180.0	6.17%	$11.1
$1,160	5.181%	$60.1

The resulting approved pre-tax weighted average cost of capital is therefore:
(35% x 14.1%) + (65% x 5.18%) = 8.3%

The equity and debt rates used in this calculation will be reviewed to ensure consistency with THESL's future rate applications or values directed by the OEB, as appropriate.

11. Singer & Watts: Cost Allocation -Methods and Regulator Decisions

OEB Decision on Enbridge

In the OEB decision in **EB-2005-0001/EB-2005-0437**, the Board conducted a thorough review of the allocation of costs for services provided by Enbridge International (EI) to Enbridge Gas Distribution (Enbridge). While the Board expressed its preference for a methodology which would begin with Enbridge determining the services it needed, it concluded that the proposed Regulatory Cost Allocation Methodology (RCAM), which started with a review of the services that EI provides, could be acceptable if there is "evidence of rigorous review by Enbridge and an independent evaluation." (Decision p. 72) The Board concluded in this instance, Enbridge failed to rigorously review the services that EI provided to establish that they were actually necessary or were provided at a cost less than Enbridge's cost to provide or acquire them as a stand alone entity. In summary, the Board found fault with Enbridge's implementation of the RCAM rather than with the RCAM itself.

The Board criticized several specific aspects of Enbridge's implementation of RCAM:

1. The Board indicated that Enbridge failed to adequately review the Service Schedules developed EI to ensure that Enbridge only paid for those services that it actually required.
2. The Board found that the time study used to allocate costs to Enbridge was inadequate. The Board required if a retrospective analysis of the time devoted to various activities be used, rather than time sheets, the analysis must be undertaken at least quarterly. The Board also required that the number of entities to which time can be allocated be expanded to include EI and several of its larger affiliates in addition to Enbridge. Finally, the Board found that time allocations should by individual salaries to better reflect cost.
3. The Board required an independent evaluation of appropriateness of the corporate cost allocations resulting from RCAM. The purpose of this evaluation is to verify that all the costs allocated to Enbridge represent costs for services required by Enbridge. The Board further required that intervenors be part of future evaluations.

In deciding the amount to be allocated to Enbridge, the Board relied on its previously formulated "three-pronged" test:

1. Cost incurrence: Were the corporate centre charges prudently incurred by, or on behalf of, the companies for the provision of services required by Ontario ratepayers?
2. Cost allocation: Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?
3. Cost/Benefit: Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?

Applying the first test, the Board found that the proposed allocation included costs that were:

1. incurred for services beyond those required by Enbridge,
2. related to "minding the investment" and thus were properly the responsibility of shareholders rather than ratepayers, or
3. represented the cost of senior EI management whose services were unnecessary to run a gas distribution utility.

As a result, the Board disallowed 50% of the costs in a number of categories that it determined went beyond the scope of service required by Enbridge. These included: Capital Market Financing and Access, Board of Directors Support, Business Development, External Communications, and Government Relations.

In discussing the second test, the Board questioned the amount of "indivisible costs," which required the use of allocators other than time. While the Board agreed with Enbridge that such allocators could be appropriate. It indicated its expectation that the independent evaluation that it ordered in the decision would reduce the amount of "indivisible time."

In analyzing the third test, the Board criticized the rigour of Enbridge's cost/benefit showing and adjusted all cost categories not adjusted for other reasons by 15% to account for this inadequate showing. The Board also identified "scale economies" as a potential benefit of services provided by the corporation, which would tend to balance the cost of corporate oversight and coordination. The Board's decision indicated that the lack of scale economies found in certain services related to IT and HR was evidence of inadequate benefit and reduced Enbridge cost request in these categories by 25%. Taking all of the disallowances described above into account, Enbridge received $17.2 million for EI costs out of a total request of $21.3 million.

Enbridge Comments

The Enbridge decision represents a thorough review of shared services costs in the context of the Gas Affiliate Relationship Code (Gas ARC). While the Gas ARC has different requirements and provides much more detail regarding the shared services transactions than the Electric ARC, it is likely to be a good guide to the evolution of shared services requirements at the OEB. The issues that the Board considered with regard to Enbridge and the arguments made by intervenors are likely to be reprised in future electric rate cases where shared services are a focus. Any shared services arrangements must be structured in a way that recognizes the Board's interpretation of the three-pronged test.

Enersource

From Enersource's Application Summary: "Enersource's corporate parent charges a management fee for services (such as Treasury, HR) and for the use of the building at the head office site."

Schedule 6-9

"Management fee = $17,423,729"

"Costs are allocated on an actual cost basis, based on prior experience."

"Corporate services provided to Enersource and allocated via the Management Fee in 2004 includes, costs incurred by: Board of Directors, Executives, Marketing and PR, Safety, HR, Customer Service and Billing, Energy Settlement Services, Finance, IT, Corporate Records, Inventory Control, Purchasing, General Corporate operating costs."

Enersource Board Decision**:**

"Enersource acquires a large number of services from its parent company and purchases these services through an annual Management Fee. The Board has the responsibility to determine the prudence of all such costs, and needs detailed information on which to base its judgment. The Applicant has presented its information clearly and has been helpful in its responses to interrogatories, but the record is still not at a satisfactory level. In future, further information will be required concerning the costs for services provided by the parent company via the Management Fee, and how these costs relate to other costs shown elsewhere in the Application, for example in Schedules 6-4, 6-5 and 6-6.

The Board notes that the upcoming cost allocation study may address its concerns to some extent, as long as the study encompasses all those activities of the affiliated entity for which Enersource pays. The Applicant is cautioned that in future, more detailed information will be required on affiliate costs."

Enersource – Comments

Clearly the information provided in the Enersource Application does not meet the requirements in the EDR Handbook. It would be useful to track down Enersource's Interrogatory responses to see what additional information was provided and better understand the calculation of the "management fee."

Hydro One

Hydro One provided a study by R.J. Rudden to support its allocation of corporate costs. The Rudden methodology looks to first directly assign common costs to Hydro One's various businesses and then allocate the remaining costs on the basis of cost causality, or benefits received, if cost causality cannot be

determined. The allocation can be influenced by factors related to implementation including practicality, stability, materiality, and minimizing effects on behavior.

At the OEB, the only aspect of the cost allocation that received any challenge was the allocation of only 2% of corporate costs to Hydro One Inc., the holding company. The Board rejected this challenge, accepting Hydro One's explanation that it, unlike the gas companies, has no unregulated subsidiaries. The Board's decision accepted Hydro One's proposed allocation in all respects for setting 2006 distribution rates and further agreed it was a reasonable approach to use in the upcoming proceeding to set transmission rates.

Ottawa

The table below presents Hydro Ottawa's forecast of services provided by affiliates for 2006. As Ottawa filed on a future test year and settled its case. There is not a lot of additional information; it is not mentioned in the Board's decision. It would be good to determine if there were any interrogatories on this subject.

Affiliate	Activity	Amount	Pricing Basis
Holding Company	Interest expense (long-term and short-term)	$13,623,915	Market-based pricing based on external debt held by the Holding Company inclusive of debt issuance costs and administration. Interest on short-term borrowing to be charged at the bank rate.
	Admin and Corporate Services expense	$1,488,000	CBP of 80% of costs, excluding some specific shareholder costs absorbed by the Holding Company
Telecom Ottawa	Broadband data services and dark fiber rental	$1,285,200	Market-based pricing based on same determinants for external customers including length of contract, number of strands, etc.

PowerStream

In 2004, PowerStream purchased $905,116 worth of services from its affiliate, the City of Vaughan including rent, postage, fuel, property services and office supplies. All these services were priced at cost, except for rent which was priced at fair market value. Schedule 6-8 of PowerStream's EDR application details how the costs of these services were determined.

PowerStream also had about $2,257,000 in shared services with the City of Vaughan during 2004. These services included: management services, human resources, purchasing, management information system, mail and courier services and record management. These services were all charged at cost. Schedule 6-9 of PowerStream's EDR application details how the costs of these services were determined. The table below provides the details regarding the determination of 2004 costs.

Activity	Cost	Pricing Basis
Management Services	$117,600	Percentage of time devoted exclusively to Hydro Vaughan/PowerStream (HV/PS) matters applied to Salaries & Benefits. Time estimates for specific positions are as follows: GM 10%, Assistant GM- Finance 20%, Assistant GM-Operations 20%, Assistant GM- Corporate Services. 10%
HR (Discontinued mid-2004)	$55,006	Based on the ratio of the approved full-time complement for HV/PS to the combined total complement for the City.
Purchasing	$120,000	35% of the departments gross operating budget in consideration of the ratio of the number of HV/PS purchase orders to the total number of purchase orders (City and HV/PS) issued and also other purchasing services provided to HV/PS such as tendering and requests for proposals.
Management information System	250,006	Operating costs are based on 30% of the total MIS operating budget. In 2004, MIS charges were based on specific services provided by the City. Any capital purchases of supplies and services by MIS on behalf of HV/PS will be invoiced to HV/PS at cost. Cost sharing for joint capital projects will be established and agreed to on a project-by-project basis as part of the project approval process.
Mail and courier	$62,254	Excluding postage, based on one third of the costs to operate the mailroom.

		Courier Based on 10% of the salary, benefits and vehicle expenses of the courier. Third party courier charges were billed to HV/PS at cost
Record Management	$20,520	10% of the section's departmental operating budget (based on the relative volume of record retention activity).

Neither purchases from affiliates or shared services were mentioned in the Board's decision. PowerStream did not receive any interrogatories inquiring into the methods it used to price shared services or affiliate transactions. It was asked to distinguish affiliate transactions from shared services and it replied that the former dealt with commodities purchased from affiliates while the latter dealt with sharing of staff equipment, or facilities.

Veridian

Below are two tables, which are excerpts from Schedule 6-8:Distribution Expenses Paid to Affiliate(s) and Schedule 6-9:Distribution Expenses Incurred Through Sharing Services with Affiliate(s) which show the services purchased from affiliates. The pricing basis is discussed below each of the tables. Because Veridian included substantial detail on its costing and allocation methodologies, these are largely included as they appear in the description of Schedule 6-8.

Schedule 6-8: For the Year 2004

Affiliate Names	Activity	Value	Basis Pricing
Affiliate X	**Describe transaction(s) with Affiliate X.**	Annual aggregate $ value of amounts paid to Affiliate X.	Did affiliate use market-based pricing or CBP?
Veridian Corporation	1) Leased Space-admin offices, service centre and stores warehouse	1,086,718	CBP
	2) Leased Office Equipment	42,492	
	3) Leased IT-Hardware/Software	295,452	
	4) Fleet Services	934,500	
Veridian Energy	1) Wholesale and Retail Settlements	583,382	Market
	2) Retail Meter Reading	659,081	CBP
	3) Customer Billing	3,560,289	Market
	4) Credit & Collections	859,362	Market & CBP
	5) Call Centre Services	**1,422,945**	Market & CBP
	6) Meter Services	795,558	CBP

"Certain services (such as those provided by VE) are purchased by the Applicant; other services (such as many of those provided by VC) comprise shared corporate services, and are identified in Schedule 6-9. Whether CBP is applied to purchased or shared services, the cost allocation methodology for both types of services is similar, and is dealt with in this Schedule."

"With respect to market-based pricing (which has been used for VE services such as wholesale settlement, retailer settlement, customer billing, certain call centre activities and credit and collections), the Applicant determined appropriate market prices through inquiries of third-party service providers as to their pricing, or recognized the market price established by the affiliate based on the affiliate's pricing of services sold to third parties. Where CBP has been used (e.g., in the pricing of services provided by VC to the Applicant and in certain services provided by VE to the Applicant), pricing has been established based on the affiliate's fully allocated costs plus a return on invested capital. Charges for services are updated annually to reflect the affiliate's proposed costs. The return on invested capital was calculated in accordance with the OEB definitions of "rate base", "approved rate of return", "deemed debt/equity ratio" and "deemed debt costs" that were in effect and applicable to the Applicant in the 2004 rate year based on the OEB EDR Handbook released in March 2000. The return is limited to the higher of the Applicant's OEB-approved rate of return or the bank prime rate. There is no return on operating costs. All services

provided to the Applicant must be provided in accordance with the current versions of all applicable OEB Codes, and with the Applicant's approved rate schedules and Conditions of Service."

"Cost Allocation Methodology:

Services provided by VC:

When establishing cost-based pricing for the services provided by VC, the charges for those services have been categorized as follows:

- Hourly charge rates for services rendered – rates are developed by position
- Lease rates for assets – includes fleet, information systems hardware & software, office furniture & equipment, space – office, service centre and storage
- Resale of materials with percentage mark-up for handling/stock fees/administration
- Vehicle Maintenance Services – actual material and third party charges with no mark up.

When establishing CBP for the services provided by VC, the activities within those services have been categorized as follows:

- Per unit rates based on identified activities within operating departments
- Per customer charge for annual provision of services within operating departments

What follows is a more detailed discussion of this methodology:
Hourly charge rates for services rendered – developed by position – Allocation basis for Shared Services as disclosed in Schedule 6-9: The following table summarizes the types of costs and allocation methodologies:

	Costs	**Allocation Methodology**
(A)	Direct Salary & Incentive Expenses	Direct Allocation by FTE – within positions
(B)	Benefits and Labour Overheads	Direct Allocation by FTE – within positions
	Space Charges – calculated as full costs for office space (operating exp, dep'n and return)	Allocated by FTE based on total of (A+B) for each FTE as percentage of total (A+B) for all FTE's – only applicable to those FTEs in 'office grouping'
	Vehicle Bay Charges – calculated as full costs for vehicle bay (operating exp, dep'n and return)	Allocated by FTE based on total of (A+B) for each FTE as percentage of total (A+B) for all FTE's -only applicable to those FTEs in 'Fleet grouping -mechanics'
	IT Charges – hardware & software – VC's capital cost of hardware & software – dep'n and return	Allocated equally to applicable FTE's
	General Admin Costs – non-departmental specific – examples: office supplies, general corporate services	Same as Space Charges
	Return on Working Capital Allowance – calc as per Elec Dist'n Rate Handbook	Same as Space Charges
	Direct Dep'tl Expenses -Other than Labour - except IT services -direct dept'l exp recovered in asset lease rates	Allocated by FTE within each department based on total of (A+B) as percentage of total (A+B) for all FTEs in that department

Where more than one FTE exists for each position, the hourly charge rate for each position is the average rate. Time will be allocated based on either employee time sheets or fixed allocations.

Lease Rates for Assets:
Where lease rates are specific by assets, return on investment is calculated by asset and recovered in lease rates.

A. Fleet:
Lease rates are calculated for each specific vehicle. Lease rates include: Return on capital cost and amortization recovery over the estimated life of the vehicle or the estimated lease period. Lease rates are divided into equal monthly payments over the estimated life of the vehicle. Once a vehicle is fully amortized within VC, lease rates to the Applicant are reduced to zero.

B. Information Systems Hardware & Software:

These assets are divided into 3 categories, Network and Workstation; Customer Information Systems; and Financial and Other application specific Systems. Lease rates are calculated on grouped assets within the year of acquisition, and are allocated within the 3 categories above. Lease rates include return on capital cost and amortization recovery over the estimated life of hardware or software investment and direct departmental expenses. Once assets are fully amortized within VC, the lease rates to the Applicant are reduced to zero. For Network and Workstation assets, allocation is on the basis of the number of workstations as a percentage of total workstations on the network. CIS and Financial and Other application system costs are allocated on the basis of numbers of System Users as percentage of Total System Users of applications.

C. Office Furniture & Equipment:
Lease rates include return on capital cost and amortization recovery over estimated life of assets. Once assets are fully amortized within VC, lease rates to the Applicant are reduced to zero.

D. Leased Space:
Lease rates include return on capital cost, amortization recovery and direct operating expenses other than labour. Charges are allocated on the basis of floor space occupied by the Applicant.

Services provided by VE:
When establishing CBP for the services provided by VE, the charges for those services have been categorized as follows:

- Per unit rates based on identified activities within operating departments
- Per customer charges for annual provision of services within operating departments

Allocation of Costs to Departments:
Proposed costs were fully allocated to each of the operating departments. Within each operating department, activities and services were then identified and fully allocated proposed costs then allocated to these activities and services based on various determinants such as managerial judgments on man and vehicle hours and direct material expenses. Unit rates were then determined based on estimated volumes of activities or on estimated customer counts.

Proposed costs were allocated to all activities and services, including those identified as having market based pricing comparators, to ensure costs were fully and properly allocated regardless of the transfer pricing mechanism used. Direct departmental operating expenses were identified for each department. Departments included departments of VE not involved in provision of services to the Applicant, such as Water Heater Rentals and External Billing & Settlement Services. In this way, it could be ensured that the Applicant would not be assigned costs related to these activities. Shared proposed costs were then allocated to each department based on the percentage of its direct operating expenses of the total of direct operating expenses of VE. Shared costs include general and administrative expenses, including administrative services incurred by VE from VC and amortization.

Amortization expenses were directly allocated to operating departments where identifiable – such as in the case of amortization of water heaters to the non-regulated activity of water heater rentals. Return on invested capital calculated (including a working capital allowance) was allocated to each department based on the percentage of its direct operating expenses of the total of direct operating expenses of VE."

Schedule 6-9 (For the Year 2004)

Affiliate Name(s)	Activity	Value	Basis Allocation
shared service(s) provider: Affiliate X	Describe the service(s) or resource(s) provided by Affiliate X.	annual $ value by service	For each type of shared cost provide summary of the cost allocator(s) used and rationale.
Veridian Corporation	• Executive and Corporate Services • Financial Services • Information Technology Services • HR and Payroll Services • Regulatory and Public Relations	947,653 1,053,425 128,049 323,459 109,317	All these services provided on hourly charge rate basis – See description below for summary of the cost allocators used and rationale

	• Stores and Purchasing Services	184,500	

"These shared services relate to common corporate activities across the Veridian family of companies, and are subject to CBP. The Applicant is aware that the OEB has accepted the concept of CBP for shared corporate services in the context of the Gas ARC, and the Applicant submits that this approach is equally appropriate in the context of electricity distributors. As noted in the context of Schedule 6-8, pertaining to services purchased from affiliates, a fundamental principle applicable to the pricing of shared services for the Applicant has been that the Applicant will pay only for distribution-related activities. Costing of shared services is based on the affiliate's fully allocated cost, plus a return on invested capital. For particulars of the Applicant's methodology applicable to CBP, please see the Applicant's comments on CBP at Schedule 6-8."

12.Singer & Watts: Cost Allocation -RCAM and Rudden

Summary of the Deloitte Consulting and R.J. Rudden Approaches to Cost Allocation and Recommendations

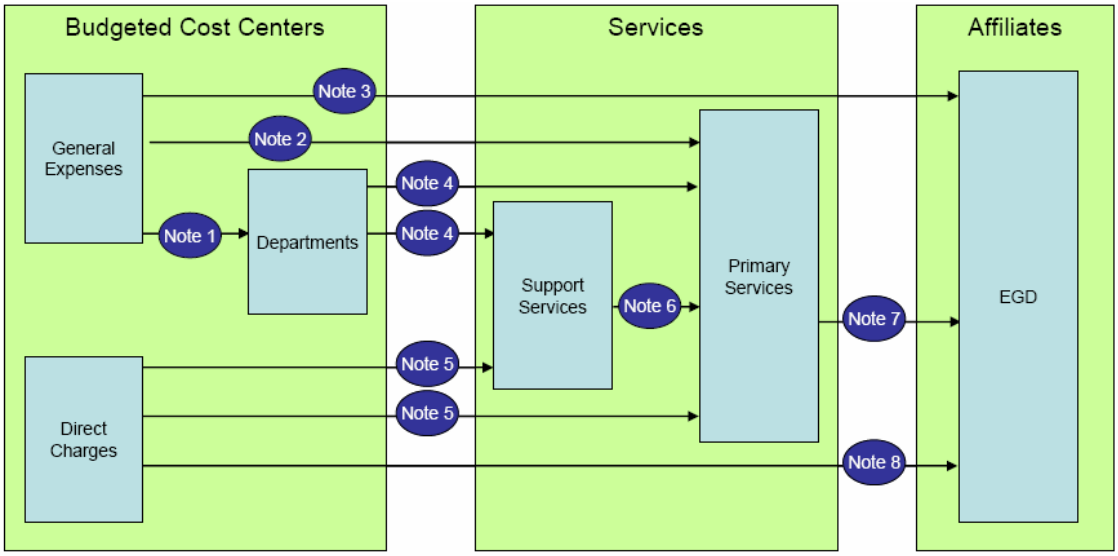
Introduction

This document summarizes the cost allocation methodologies found in the reports by Deloitte Consulting for Enbridge and R.J. Rudden for Hydro One. It finds that the Rudden approach offers advantages for Toronto Hydro because it is simpler and has achieved greater regulatory acceptance. Moreover, because Hydro One's structure with regard to subsidiaries and allocation issues is more similar to the structure of Toronto Hydro than the Enbridge structure is, the Rudden approach is likely to be more applicable.

Deloitte Methodology

Description of the Methodology

Deloitte was retained originally by Enbridge Gas Distribution ("EGD" the Ontario-based gas distribution company) to review the method used to allocate costs from Enbridge International ("EI" the holding company). This approach, known as Cost Allocation Method ("CAM"), had been criticized by the Ontario Energy Board ("OEB" or "Board") in RP-2002-0133. As a result of the deficiencies identified in CAM, Enbridge retained Deloitte to develop a new method known as the Regulatory Cost Allocation Method ("RCAM") for use in determining the amounts to be included in rates in OEB proceedings. [16]



Source: Deloitte Report – Appendix 3, p. 9

The basic approach employed by Deloitte Consulting Services to establish a cost allocation method for EI and EGD is illustrated in the diagram above taken from the Deloitte Report. The major initiative is to categorize the work of each EI department into various primary and support services. Primary services are those, which EGD acknowledges would be necessary for it to operate as a stand alone business. Support services are those that EGD agrees are necessary to support the primary services. The cost of services that EGD views as unnecessary are not allocated to EGD.

[16] While RCAM is used to determine the amount of common cost that EGD believes should be included in its revenue requirement for cost recovery from ratepayers, CAM continues to be used to determine the amount of costs that EGD is required to pay to EI.

This approach produces an allocation based on services rather than departments. The goal is to start with the cost of the services that EGD requires rather than the cost of the EI departments that provide corporate services. All service costs are allocated using an allocator selected as appropriate for that specific service. Each service is evaluated individually for its costs and benefits.

In addition, certain EI costs are identified as general expenses and others are called direct charges. General expenses are separately budgeted for management purposes and include items such as business taxes and employee benefits. Some of these are allocated to the EI Departments, some are allocated to primary services and others are directly assigned to particular affiliates. Direct charges include two types of costs. The first are costs incurred specifically for and charged to affiliates and include items such as audit fees and insurance premiums. The second are costs incurred by EGD and other affiliates on behalf of EI, which are allocated to either primary or support services.

To the greatest extend possible, the Deloitte method attempt to allocate the cost of primary services to EGD based on the time spent delivering the service to EGD. Activities that cannot be allocated based on time are placed in an indivisible cost category for each service and allocated based on cost causality using appropriate allocators. Examples include headcount and capital employed.

Basic Principles and Parameters

The basic principles identified as underlying the methodology developed in the Deloitte Report are:

- Consistency with OEB requirements including the three pronged test, the Affiliate Relationships Code for gas utilities, and regulatory precedents.
- Transparency in the definition and allocation of services including the full documentation of service and allocator definitions, and the use of allocations "supported by verifiable data and records wherever practicable."
- Simplicity in the allocation method is a key objective recognizing that more than one allocation step may be required, but attempting to use the fewest possible allocation steps.
- Cost causality should be the basis of all allocations subject to a materiality threshold.

In the context of the cost allocation methodology, the Deloitte Report defines the three pronged test as follows:

- EGD must need the service that is provided, and the costs must be prudently incurred on behalf of EGD
- The allocators (and charges) must be based as far as possible on causality or benefits received
- The benefits to EGD (ratepayers) must equal or exceed the costs

In Deloitte's view the following principles are at the core of its cost allocation design:

- Services Based Approach
- Service Description Transparency
- Stand Alone Entity
- Multi-Step Allocation Process

Time Allocation

Deloitte endeavoured to standardize time allocation by presenting the following approach:

- Determine how much time each individual at EI spends in providing each service covered by a service agreement between EI and EGD;
- Compute how much of the time spent on each service should be allocated to EGD.

The allocation approach begins with individuals allocating 100% of their time to various primary and support services. This time was then split into the following categories: EGD, Other Affiliates (excluding EGD) and All Affiliates. The All Affiliates category accounts for time, which is indivisible. These allocations were largely based on historical experience modified by known future events that are expected to alter the historical experience.

The description of the time allocation method in Appendix 4 of the Deloitte Report distinguishes between the treatment of administrative time and management activities. (Appendix 4, p. 2) Administrative activities are allocated as a separate support service, while management time is embedded in each service.

Criticism of RCAM by the OEB

The RCAM methodology was reviewed by the OEB in EB-2005-0001/EB-2005-0437. The Board criticized RCAM on several dimensions, but found it would be an acceptable allocation methodology if several specific problems identified were addressed. First, the Board found that the definition of the primary services depended more on what EI did rather than what EGD required. (EB-2005-0001/EB-2005-0437, pp.72-73) The Board required better description of how EI's primary services were translated in the service schedules with EGD and a more transparent presentation of the relationship among EI department costs, the costs of the primary services and the costs included in the service agreements with EGD. Second, the Board faulted EI's time reporting and indicated that if actual time records were not used, a quarterly time study was required. The Board also indicated that the time reporting categories should be expanded to include categories for EI and several of the larger EI affiliates. Finally, the Board concluded that Deloitte's evaluation of the RCAM results was not independent and that an independent review of EI's cost allocation, including stakeholder involvement was required.

In reviewing the allocated amounts, the Board concluded that some of the EI services included costs that were not required for the prudent provision of EGD's regulated gas distribution service. On this basis, the Board reduced the cost allocated to EGD by $2.7 million or half the cost of the services in question. The Board also made other disallowances because it viewed the claimed costs as exceeding the amount EGD would expend as a stand-alone utility. In some areas, the Board specifically required the demonstration of scale economies that would result in costs lower than those that EGD could obtain on its own. In total the Board disallowed $4.1 million of EGD's $21.3 million request.

<u>Rudden Methodology</u>

Description of the Rudden Methodology

R.J. Rudden Associates was retained by Hydro One Networks Inc. to conduct a study of its methodology for allocating common costs. This effort responds to OEB direction in RP 1998-001 that Hydro One improve its allocation of shared services costs. Hydro One's business units include Hydro One Inc. (the parent corporation) and its various subsidiaries (Distribution, Transmission, Brampton, Remote Communities and Telecom). The common corporate functions and services (CCFS) being allocated are listed in the following table.

TABLE 1 FUNCTIONS AND ACTIVITIES IN CCFS	
• Hydro One Inc. Corporate Office	• Customer Support Operations
• Corporate Services	• Settlements
• Finance	• Finance and Accounting Services
• General Counsel	• Human Resources
• Telecom Services	• Supply Management Services
• Strategic Planning & Business Development	• ETS- Applications Support and Infrastructure Support

Source: Rudden Report, p. 2.

The costs of CCFS are approximately $235.4 million in 2006. Of this amount, 49% is attributable to an outsourcing arrangement with Inergi LP. The Inergi contract includes the provision of certain services that are known as "sustainment" services. The cost of these services is largely locked-in for the ten-year term of the Inergi contract and these costs are included as CCFS.

The Rudden methodology begins by identifying the activities that are required to perform the CCFS. The costs of each of the functions and services are then allocated to the activities required to perform it using time and cost studies. The cost of the various activities are then distributed among the business units using direct assignment or, where direct assignment is not possible, cost drivers based on cost causation. In addition to cost causality, the selection of cost drivers also took into account cost effectiveness, simplicity, regulatory precedents and flexibility.

Of the CCFS budgeted costs, between 36% and 38% were direct assigned to business units.[17] The remainder was assigned using cost drivers. These include external measures such as physical units (e.g. number of customers, employees or time studies), financial measures (e.g. capital expenditures, net utility plant or total revenue) and internal measures that rely on a previous allocation step (e.g. the cost of a supervisor being allocated based on the allocation of the various activities supervised).

The activities undertaken to perform each of the corporate functions and services were identified in discussions between Rudden and Hydro One personnel. Rudden then prepared a list of activities for each function or service and had this validated by Hydro One. The identified activities accounted for 98% of the total budgeted 2006 cost of the resources needed to provide the CCFS. Similarly, Rudden reviewed the labour and non-labour portions of the budgets for each CCFS supplied by Hydro One and performed an allocation of Inergi charges, which was reviewed by Hydro One. Finally, based on information from Hydro One, Rudden identified the business units that use the CCFS. These include the five subsidiaries previously identified and a category called "Shareholder" that represents activities undertaken exclusively to benefit Hydro One's sole shareholder.

The allocation of labour costs to specific activities was accomplished through discussions with the manager in charge of each CCFS. Using time records, interviews and informed judgment, the manager allocated his unit's labour costs to the various activities it performs. Rudden allocated non-labour costs by examining the individual items and assigning them using an appropriate allocator. This process accounted for approximately 95% of the CCFS non-labour costs. Rudden and Hydro One allocated Inergi costs based on the nature of the costs and judgment exercised by Rudden.

Once the activities were assigned costs, the next step was to assign the costs for each activity to business units. Wherever possible, the costs were assigned directly to distribution, transmission or other. Where direct assignment of 100% of an activity's cost was not possible, the activity was allocated among three categories: 1) transmission and distribution; 2) transmission, distribution and other; and 3) materials surcharge. Category 1 includes activities that relate solely to transmission and distribution, but the split between them cannot be directly determined. Category 2 includes activities that relate to transmission, distribution and at least one other of Hydro One's business units, and the split cannot be directly determined. Category 3 includes most of the cost of Hydro One's Supply Management Services function.[18]

The next step was to select cost drivers to allocate the amounts in the three categories above to specific business units. These cost drivers were developed by Rudden as discussed above. Numerical values and percentages were developed for each cost driver in each of three business units (distribution, transmission and other). For example, one of the cost drivers is number of FTEs. The total number of FTEs in Hydro One was divided among the distribution, transmission and other business units, and the percentage of the total represented by each business unit was calculated. Applying the percentages developed for each cost driver to the cost of each activity allocated using that driver produced an allocation of costs to specific business units. The final step was to add the costs allocated using cost drivers to the directly assigned costs for each activity so as to arrive at a total cost for each activity in each business unit.

[17] The Rudden Report is inconsistent in reporting the percentage of CCFS costs that are directly assigned. On page 5 it says 38% and on page 8 it says 36%.

[18] A small portion of the costs of the Supply Management Services function is allocated to Category 1 (transmission and distribution). Unfortunately, the Rudden Report does not describe how the materials surcharge is applied.

Rudden reviewed the results with Hydro One for reasonableness. Hydro One proposes to use the values developed to assign estimated costs to each business unit. These estimated costs would be updated to reflect differences between the total estimated costs assigned and the actual total costs. Another source of difference will occur because the estimated cost of each activity and the estimated values of the cost drivers will differ from the actual values. Rudden proposes that an end-of-year adjustment for each business unit be used to reflect the actual values of activity costs and cost drivers.

OEB Reaction to the Rudden Methodology

In RP-2005-0020/EB-2005-0378, the Board reviewed Hydro One's distribution rate application. This application allocated common costs using the Rudden Methodology. The methodology received little scrutiny and the Board stated: "The Board notes that all intervenors accepted the Rudden study as a fair and balanced approach to allocate joint costs and the Board agrees with that assessment." The Board indicated that one factor distinguishing Hydro One from the gas utilities is that Hydro One only has regulated subsidiaries.[19] (RP-2005-0020/EB-2005-0378, p. 22) Neither the Board nor intervenors sought an independent review of the results of the cost allocation proposed by Rudden.

<u>Comparison between the Deloitte and Rudden Methodologies</u>

While described in different terms and presented in different levels of detail, substantial similarities exist between the Deloitte and Rudden methodologies. Deloitte starts with EI's budgeted cost centers, which include departments, direct charges and general expenses, while Rudden starts with Hydro One's common corporate services and functions (CCFS). Deloitte then allocates the amounts in the budgeted cost center costs to services (both primary and support), but also allocates some expenses and charges directly to affiliates. Rudden allocates the CCSF costs to activities. Perhaps the biggest difference is in the final step where Deloitte allocates the cost of the services, general expenses and direct charges to affiliates. Rudden assigns the cost of the CCFS activities directly to three major business units (36-38% of the costs) and allocates the remainder of the costs to the three business units using cost drivers.

This difference seem to reflect the differences in the way EI and Hydro One categorize costs and fundamental differences in the nature of the cost allocation task. From the information in the Rudden Report, it does not appear that Hydro One has an equivalent to EI's general expense and direct charge categories. With regard to the cost allocation task, EI is a multi-jurisdictional holding company with many subsidiaries regulated by several regulatory bodies. Thus, it incurs some costs that have no connection to EGD. As a result, EI has much larger task in defining which of its costs are appropriately allocated to EGD. This has led it to adopt a service based approach to costs, whereby it attempts to identify needed services and allocate the costs of these services, rather than departmental costs, to EGD.

In contrast, Hydro One is an Ontario company with two primary subsidiaries, transmission and distribution, both of which are regulated by the OEB. For Hydro One, other activities are miniscule in relation to the regulated businesses. As a result, it is legitimate to conclude, as the OEB did, that virtually all of its CCSF activities go to support one or both of Hydro One's regulated businesses. Based on this reasoning, the Board did not require Hydro One to demonstrate that all the activities included in the CCSF were all required by its regulated distribution business.

In Hydro One's case, the main task is to allocate activities costs between the regulated transmission business and the regulated distribution business. This is a simpler and much less controversial task than the one facing EI and EGD.

[19] This conclusion is not strictly correct as Hydro One Telecom is not regulated, but it represents less than 1% of Hydro One's revenues and assets.

Recommendations

Neither the Deloitte nor the Rudden study does a particularly good job in defining the costs to be allocated. Deloitte presents no information about why some costs are classified as general expenses and others are called direct charges other than to say this is how EI classifies them. Rudden provides little information about how the costs of functions that provide service to other functions in the CCSF are handled. For example, to the extent that Information Management and Technology provides services to other departments, it appears that those costs remain in Information Management rather than being assigned to the recipient departments, but this is not completely clear. Moreover, neither Deloitte nor Rudden explains how capital items and return on invested capital are treated in the cost allocation process. Toronto Hydro should do a better job of describing the costs to be allocated, particularly capital costs.

In terms of the allocation, the Rudden methodology appears to be much simpler because it starts with each CCFS department and allocates virtually its entire budget to activities.[20] These activities are either directly assigned to transmission, distribution or other; or allocated solely to transmission and distribution or to transmission, distribution and other. The allocated costs are then assigned among the transmission, distribution and other categories using allocators that reflect Rudden's and Hydro One's views of cost causality. The relative simplicity of this approach makes it a more appropriate model for Toronto Hydro.

Relative to the size of Toronto Hydro, non-regulated subsidiaries are bigger and more visible than they are for Hydro One. Nevertheless, Toronto Hydro is still more like Hydro One in this regard than it is like EI. Given this greater similarity to Hydro One and the acceptance of the Rudden methodology by the OEB, the Rudden Approach appears to offer a better starting point for Toronto Hydro. However, Toronto Hydro will need to be more rigorous in its definition of the costs to be allocated and in its demonstration that an appropriate portion of overall corporate costs are being allocated to its non-regulated activities. In addition, because Toronto Hydro is relying on an internally developed cost allocation method, an independent review of the proposed methodology and its application is essential if the cost allocation is to be accepted during regulatory review.

[20] The Rudden Report indicates that the identified activities capture 98% of the CCFS costs, but does not indicate what happens to the other 2%. (See Rudden Report, p. 11)

13. Time Study Internal Memo

toronto hydro corporation

memo

date	March 2, 2007
attention	All THC Staff
copy	
from	JS Couillard
subject	Allocations to Affiliates

The OEB's Decision in THESL's 2006 Rate Application directed us to improve how we allocate costs among our affiliated companies. More specifically, we are directed to use time-based allocations to the extent possible.

Your assistance is required to help us develop these time allocation factors for the period March 1, 2007 to May 31, 2007. We need your estimates in determining the proportion of your time spent supporting each affiliate.

The attached template should be completed by each employee and submitted to Emma DeLint (x30885) on a weekly basis on the following Monday. Should you have any questions, please contact Ray Tiam-Fook (x22836) or Ann Grant (x22867).

JS Couillard

14. Time Study Template

WORK TIME ALLOCATIONS FOR SHARED SERVICES

Instructions:

enter information in cells shaded yellow only;

do not consider time not at work (e.g. vacation, sick, holiday) or administrative duties (e.g. team meetings, performance reviews)

email completed timesheet to Emma Delint on the following Monday.

descriptions are required-briefly for each district-see examples provided

							(hours)	(hours)	(hours)	(hours)	(hours)	
Week #	**Day #**	**Date**	**Weekday**	**Employee Number**	**Employee Name**	**RC**	**THESL**	**THC**	**THTI**	**THESI**	**TOTAL**	**Description**
1	1	February 26, 2007	Monday									
1	2	February 27, 2007	Tuesday									
1	3	February 28, 2007	Wednesday									
1	4	March 1, 2007	Thursday									
1	5	March 2, 2007	Friday									
1	6	March 3, 2007	Saturday									
1	7	March 4, 2007	Sunday									
						Subtotal						
						Percent						

Week #	**Start**	**End**	**Day Start**	**Day End**
1	February 26, 2007	March 4, 2007	1	7
2	March 5, 2007	March 11, 2007	8	14
3	March 12, 2007	March 18, 2007	15	21
4	March 19, 2007	March 25, 2007	22	28
5	March 26, 2007	April 1, 2007	29	35
6	April 2, 2007	April 8, 2007	36	42
7	April 9, 2007	April 15, 2007	43	49
8	April 16, 2007	April 22, 2007	50	56
9	April 23, 2007	April 29, 2007	57	63
10	April 30, 2007	May 6, 2007	64	70
11	May 7, 2007	May 13, 2007	71	77
12	May 14, 2007	May 20, 2007	78	84
13	May 21, 2007	May 27, 2007	85	91
14	May 28, 2007	June 3, 2007	92	98

15. Related Documents

Inventory of Transactions

Report of the Expert Panel on Fair Market Value

THC/THESL Business Analysis of the Findings of the Fair Market Value Expert Panel

Independent Review

Executive Inventory Sign Offs

SLA Executive Sign-Offs

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Stewardship & Leadership - CEO	Provide strategic direction, leadership and communication to the organization.	THC	THESL
Governance - Board of Directors	Provide strategic direction, leadership and communication to the organization.	THC	THESL
Legal Stewardship	Provide strategic direction, leadership and communication to Legal Services and the organization.	THC	THESL
Legal Commercial	Legal advice on commercial contracts; general corporate policies, procedures, including drafting and legal review of documents for execution	THC	THESL
Legal Commercial	Legal advice on commercial contracts; general corporate policies, procedures, including drafting and legal review of documents for execution.	THESL	THC
Legal Commercial	Legal advice on commercial contracts; general corporate policies, procedures, including drafting and legal review of documents for execution.	THESL	THESI
Legal Commercial	Legal advice on commercial contracts; general corporate policies, procedures, including drafting and legal review of documents for execution.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Litigation	Initiation and defence of legal proceedings for and against TH & Affiliates; legal advice on revenue recovery processes (Claims & Collections).	THESL	THESI
Litigation	Initiation and defence of legal proceedings for and against TH & Affiliates; legal advice on revenue recovery processes (Claims & Collections).	THESL	THTI
Litigation	Initiation and defence of legal proceedings for and against TH & Affiliates; legal advice on revenue recovery processes (Claims & Collections).	THESL	THC
Real Property	Initiation, drafting and review of legal documents (Offer to Connect, Supply Agreement, Alternative Bid Proposal, Easement) related to real property development and supply arrangements thereto; Advice on and preparation of legal documents for execution for TH real property transactions; Investigate and respond to easement inquiry letters from purchasers of property.	THESL	THC

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Real Property	Initiation, drafting and review of legal documents (Offer to Connect, Supply Agreement, Alternative Bid Proposal, Easement) related to real property development and supply arrangements thereto; Advice on and preparation of legal documents for execution for TH real property transactions; Investigate and respond to easement inquiry letters from purchasers of property.	THESL	THESI
Real Property	Initiation, drafting and review of legal documents (Offer to Connect, Supply Agreement, Alternative Bid Proposal, Easement) related to real property development and supply arrangements thereto; Advice on and preparation of legal documents for execution for TH real property transactions; Investigate and respond to easement inquiry letters from purchasers of property.	THESL	THTI
Claims Administration	Administration of Claims against third parties; Assist in defence efforts of claims and legal proceedings against TH and Affiliates.	THESL	THESI
Finance - Stewardship	Provide strategic direction, leadership and communication to the Finance group and the organization.	THC	THESL

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Corp. Controllership & Policy	Ensure compliance with control-oriented policies, obligations, and the independent auditors. Manages consolidated month-end, quarter-end and annual close processes and oversees functions related to Financial Reporting, General Ledger. Responsible for all OSC (including MD&A), OEB, and other finance-related external reporting. Manages consolidated budget process and all other corporate planning related reporting.	THC	THESL
Reporting, Policy	Preparation of financial statements, preparation of quarterly and annual OSC filings in accordance with Accounting Standards. Develop Internal Accounting Policies in accordance with GAAP Standards & OEB requirements, ensure reporting is in compliance with Policies and Standards.	THC	THESL
Corporate Tax	Provide professional corporate tax planning, consulting services on compliance on tax matters including tax research and preparation of tax filings.	THC	THESL
Financial Planning Admin	Facilitating and documenting the strategic and business planning processes. Support rating agencies requirements. Financial modelling of business initiatives.	THC	THESL

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Internal audits, securities regulation compliance, and advisory services	> Internal audits and related reports to management and the Board of Directors of THC > Bill 198/CSA instrument 52-109 (securities regulation related to disclosure and internal controls) compliance activities and reports to management and the Board of Directors of THC > Business advisory services related to operational efficiencies and effectiveness of internal controls > Advisory Services for management special projects (new CIS implementation, smart meters) > Audits and reviews will cover the following areas: - Business/operational controls (including manual and automated controls) - IT general controls - Entity controls - Fraud controls	THC	THESL
Comm. & Public Affairs - Stewardship	Provide strategic direction, leadership and communication to the Communication group and the organization for THESL issues such as CDM, outages and rate changes.	THC	THESL
Comm. & Public Affairs - Strategic Projects	The strategic planning, development and execution of public affairs management programs in support of corporate business plans, strategic thrusts, brand identity and corporate reputation management.	THC	THESL

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
EHS - Stewardship	Provide strategic direction, leadership and communication to the EHS, CDM groups and the organization. Advice on issues related to due diligence, compliance, best practices, bench marking, verification, reporting mechanisms and corporate organization and accountability.	THC	THESL
EHS - Safety	Provide recommendations and advice on EHS issues. Conduct and co-ordinate health & safety educations and trainings, maintain health and safety records. Accident/incident investigations.	THESL	THESI
EHS - Safety	Provide recommendations and advice on EHS issues. Conduct and co-ordinate health & safety educations and trainings, maintain health and safety records. Accident/incident investigations.	THESL	THTI
EHS - Environmental	Provide recommendations and advice on scope and content of environmental issues, co-ordinate and conduct environmental related training.	THESL	THESI
EHS - Environmental	Provide recommendations and advice on scope and content of environmental issues, co-ordinate and conduct environmental related training.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
EHS - Occupational Health	Health Services will co-ordinate the disability management process for absences of an occupational and non-occupational illness or injury.	THESL	THESI
EHS - Occupational Health	Health Services will co-ordinate the disability management process for absences of an occupational and non-occupational illness or injury.	THESL	THTI
EHS - WSIB	Occupational and non-occupational claims management services.	THESL	THESI
EHS - WSIB	Occupational and non-occupational claims management services.	THESL	THTI
Organizational Effectiveness - Stewardship	Provide strategic direction, leadership and communication to the OE group and the organization.	THC	THESL

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Treasury, Rates & Regulatory	> Cash management: Daily cash management (investments, wires, electronic payments, etc) > Credit management: Management of letters of credit, parental guarantees, prudential requirements > Debt management: Short-Term and Long-Term debt management (coupon payments, note management, LOC management, etc) > Financing Strategy: Strategic financial planning (project analysis, capital structure analysis, financing plans, etc) > Insurance management: Management of Insurance services (property, casualty, vehicle, etc) > Investor Relations: Providing investor relations (credit rating agencies, creditors, public) > Monthly accounting/reporting: Financial reporting and record keeping (banking, investments, Shareholder report, MD&A, etc)	THESL	THC

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Treasury, Rates & Regulatory	> Cash management: Daily cash management (investments, wires, electronic payments, etc) > Credit management: Management of letters of credit, parental guarantees, prudential requirements > Debt management: Short-Term and Long-Term debt management (coupon payments, note management, LOC management, etc) > Financing Strategy: Strategic financial planning (project analysis, capital structure analysis, financing plans, etc) > Insurance management: Management of Insurance services (property, casualty, vehicle, etc) > Investor Relations: Providing investor relations (credit rating agencies, creditors, public) > Monthly accounting/reporting: Financial reporting and record keeping (banking, investments, Shareholder report, MD&A, etc)	THESL	THESI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Treasury, Rates & Regulatory	> Cash management: Daily cash management (investments, wires, electronic payments, etc) > Credit management: Management of letters of credit, parental guarantees, prudential requirements > Debt management: Short-Term and Long-Term debt management (coupon payments, note management, LOC management, etc) > Financing Strategy: Strategic financial planning (project analysis, capital structure analysis, financing plans, etc) > Insurance management: Management of Insurance services (property, casualty, vehicle, etc) > Investor Relations: Providing investor relations (credit rating agencies, creditors, public) > Monthly accounting/reporting: Financial reporting and record keeping (banking, investments, Shareholder report, MD&A, etc)	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Accounts payable and related services.	> Process and pay (by cheque, wire payment, EFT): - supplier invoices - cheque requisitions - customer refunds - employee expense reimbursements > Maintain (including testing) Ellipse modules and business processes related to AP > Manage the recording of accruals (THESL and THC only) > Audit/review and summary of expense claims, executive expenditures > Maintain internal controls on physical supplies (cheques, keys etc.) and periodic review of risks > Monthly account reconciliations of AP accounts (THESL and THC only) > Interface and assist Tax and Treasury with AP related matters > General client support including assisting with requisitioning and payment-related issues and fielding supplier calls	THESL	THESI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Accounts payable and related services.	> Process and pay (by cheque, wire payment, EFT): - supplier invoices - cheque requisitions - customer refunds - employee expense reimbursements > Maintain (including testing) Ellipse modules and business processes related to AP > Manage the recording of accruals (THESL and THC only) > Audit/review and summary of expense claims, executive expenditures > Maintain internal controls on physical supplies (cheques, keys etc.) and periodic review of risks > Monthly account reconciliations of AP accounts (THESL and THC only) > Interface and assist Tax and Treasury with AP related matters > General client support including assisting with requisitioning and payment-related issues and fielding supplier calls	THESL	THC

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Accounts payable and related services.	> Process and pay (by cheque, wire payment, EFT): - supplier invoices - cheque requisitions - customer refunds - employee expense reimbursements > Maintain (including testing) Ellipse modules and business processes related to AP > Manage the recording of accruals (THESL and THC only) > Audit/review and summary of expense claims, executive expenditures > Maintain internal controls on physical supplies (cheques, keys etc.) and periodic review of risks > Monthly account reconciliations of AP accounts (THESL and THC only) > Interface and assist Tax and Treasury with AP related matters > General client support including assisting with requisitioning and payment-related issues and fielding supplier calls	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Payroll processing and related activities	> Process payroll > Prepare T4's, T4A's > Prepare and submit payroll related remittances to government and other external agencies > Maintain (including testing) Ellipse modules, ADP applications, and business processes related to payroll > Maintain internal controls and periodic review of risks > Monthly account reconciliations related to payroll accounts > Interface and assist HR payroll related matters and general client support	THESL	THESI
Payroll processing and related activities	> Process payroll > Prepare T4's, T4A's > Prepare and submit payroll related remittances to government and other external agencies > Maintain (including testing) Ellipse modules, ADP applications, and business processes related to payroll > Maintain internal controls and periodic review of risks > Monthly account reconciliations related to payroll accounts > Interface and assist HR payroll related matters and general client support	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Payroll processing and related activities	> Process payroll > Prepare T4's, T4A's > Prepare and submit payroll related remittances to government and other external agencies > Maintain (including testing) Ellipse modules, ADP applications, and business processes related to payroll > Maintain internal controls and periodic review of risks > Monthly account reconciliations related to payroll accounts > Interface and assist HR payroll related matters and general client support	THESL	THC
Communications & Public Affairs - External Communications	Assist in the execution of public and stakeholder relations programs to the public, media, shareholder and stakeholders. Provide brand oversight.	THESL	THC
Community Involvement	The strategic planning, development and execution of community involvement, corporate sponsorship and corporate responsibility.	THESL	THC
Community Involvement	The strategic planning, development and execution of community involvement, corporate sponsorship and corporate responsibility.	THESL	THESI
Community Involvement	The strategic planning, development and execution of community involvement, corporate sponsorship and corporate responsibility.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
HR - Planning, Benefits and Compensation	Primarily responsible for: providing support for organizational staff planning; the design and administration of active and retiree benefits programs; design and administration of compensation systems; salary administration; job evaluation; and the management of the Human Resources Information System and reporting requirements. Services also include: supporting the design and implementation of HR strategic initiatives; the design, assessment and audit of internal HR policies, programs and processes; providing data to financial/regulatory reporting and rate filing.	THESL	THC
HR - Services	Supports employees and leaders in the following primary areas: labour & employee relations; recruitment, selection & on-boarding; job analysis & design; employee performance and attendance management; legislative compliance; supporting corporate initiatives; providing data to financial/regulatory reporting and rate filing; and the development of HR policies and procedures.	THESL	THC

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
OD&P	Provides support in the following areas: Performance Management Systems, Training and Development Systems (including Trades and Technical Training), Leadership Development/Succession Planning, Change Management Methods, Engagement and Communication, OD Consulting and Facilitation, Strategic Project Support.	THESL	THC
Project Support Office	Provides support on Project Management and Project Risk Management, assists in Process Improvement methods, and co-ordinates Key Performance Indicators (KPI) and scorecard reporting within Management Control and Reporting Systems.	THESL	THC
IT Stewardship	Provide leadership to ensure that "Ellipse" and "Hyperion" related IT investments are aligned and delivered in accordance with enterprise strategies and objectives and that Affiliate Relationship Codes are observed.	THESL	THESI
IT Stewardship	Provide leadership to ensure that "Ellipse" and "Hyperion" related IT investments are aligned and delivered in accordance with enterprise strategies and objectives and that Affiliate Relationship Codes are observed.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
IT Stewardship	Provide leadership to ensure that "Ellipse" and "Hyperion" related IT investments are aligned and delivered in accordance with enterprise strategies and objectives and that Affiliate Relationship Codes are observed.	THESL	THC
IT-Management Services	Maintain and implement "Ellipse" and "Hyperion" based IT infrastructure, such as enterprise systems, enterprise database and enterprise storage needs and that they are separated and yet incorporated as part of Enterprise IT Infrastructure.	THESL	THESI
IT-Management Services	Maintain and implement "Ellipse" and "Hyperion" based IT infrastructure, such as enterprise systems, enterprise database and enterprise storage needs and that they are separated and yet incorporated as part of Enterprise IT Infrastructure.	THESL	THTI
IT-Management Services	Maintain and implement "Ellipse" and "Hyperion" based IT infrastructure, such as enterprise systems, enterprise database and enterprise storage needs and that they are separated and yet incorporated as part of Enterprise IT Infrastructure.	THESL	THC
IT-Client Services	Provide one-stop help desk for "Ellipse" and "Hyperion" related services. Maintain and support administration services related to "Ellipse" and "Hyperion", such as user id's, password resets, network file sharing and network printers.	THESL	THESI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
IT-Client Services	Provide one-stop help desk for "Ellipse" and "Hyperion" related services. Maintain and support administration services related to "Ellipse" and "Hyperion", such as user id's, password resets, network file sharing and network printers.	THESL	THTI
IT-Client Services	Provide one-stop help desk for "Ellipse" and "Hyperion" related services. Maintain and support administration services related to "Ellipse" and "Hyperion", such as user id's, password resets, network file sharing and network printers.	THESL	THC
IT-Operations	Maintain data centre operations including data centre facility management. Support "Ellipse" and "Hyperion" production services such as daily production, batch operations and network data backup.	THESL	THESI
IT-Operations	Maintain data centre operations including data centre facility management. Support "Ellipse" and "Hyperion" production services such as daily production, batch operations and network data backup.	THESL	THTI
IT-Operations	Maintain data centre operations including data centre facility management. Support "Ellipse" and "Hyperion" production services such as daily production, batch operations and network data backup.	THESL	THC

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Network/Telephony	Maintain and support data network connectivity between THESL and Affiliate in order to access "Ellipse" and "Hyperion" applications.	THESL	THESI
Network/Telephony	Maintain and support data network connectivity between THESL and Affiliate in order to access "Ellipse" and "Hyperion" applications.	THESL	THTI
Network/Telephony	Maintain and support data network connectivity between THESL and Affiliate in order to access "Ellipse" and "Hyperion" applications.	THESL	THC
IT Strategy & Governance	Provide Governance and Strategic Leadership to ensure that "Ellipse" and "Hyperion" related IT investments are aligned and delivered in accordance with enterprise strategies and objectives and to ensure that ARC is enforced.	THESL	THESI
IT Strategy & Governance	Provide Governance and Strategic Leadership to ensure that "Ellipse" and "Hyperion" related IT investments are aligned and delivered in accordance with enterprise strategies and objectives and to ensure that ARC is enforced.	THESL	THC

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
IT Strategy & Governance	Provide Governance and Strategic Leadership to ensure that "Ellipse" and "Hyperion" related IT investments are aligned and delivered in accordance with enterprise strategies and objectives and to ensure that ARC is enforced.	THESL	THTI
IT-Application Support	Maintain and support "Ellipse" Enterprise application, including L2 and L3 support.	THESL	THESI
IT-Application Support	Maintain and support "Ellipse" Enterprise application, including L2 and L3 support.	THESL	THTI
IT-Application Support	Maintain and support "Ellipse" Enterprise application, including L2 and L3 support.	THESL	THC
Procurement Charge	Charge used to recover department's expenses in processing purchase orders. RFPs/bulk purchasing.	THESL	THC
Procurement Charge	Charge used to recover department's expenses in processing purchase orders. RFPs/bulk purchasing.	THESL	THESI
Procurement Charge	Charge used to recover department's expenses in processing purchase orders. RFPs/bulk purchasing.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Locates Services	Upon requests from Street Lighting Locates Dept. will complete locate services related to third party locate requests.	THESL	THESI
Fleet Services	Usage and maintenance of vehicles and trucks.	THESL	THC
Fleet Services	Usage and maintenance of vehicles and trucks.	THESL	THESI
Fleet Services	Usage and maintenance of vehicles and trucks.	THESL	THTI
Facilities	Occupancy charges for various types of space.	THESL	THC
Facilities	Occupancy charges for various types of space.	THESL	THTI
Facilities	Occupancy charges for various types of space.	THESL	THESI
CDM Incentives	Incentives to complete customer CDM programs that result in kW savings.	THESL	THESI
Distribution Grid Management	Overhead line relocations to accommodate installation of Telecom fibre attachments to THESL poles.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Distribution Grid Management	Overhead & Underground street light equipment installation, removal, and/or transfer as part of emergency corrective maintenance requirements.	THESL	THESI
Distribution Services	Overhead & Underground street light equipment installation, removal and/or transfer as part of planned projects. Civil street light infrastructure installations as part of planned projects.	THESL	THESI
Distribution Services	Installation of street lighting GIS data into new GEAR system.	THESL	THESI
Duct rental	Run Fibre optic cable through underground ducts.	THESL	THTI
Emergency Services/System Response	Notification of critical impact on street lighting plant. Resources sent to provide emergency support/response.	THESL	THESI
GEAR Access	Access to THESL's geo-electric records system.	THESL	THTI
GEAR Access	Access to THESL's geo-electric records system.	THESL	THESI
Hold-offs	Block circuit reclosures when requested by work crews.	THESL	THTI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Hold-offs	Block circuit reclosures when requested by work crews.	THESL	THESI
Investment Planning Design Mark Ups	Upon request from street lighting (operated by THESI), mark ups are completed by Investment Planning staff on planned construction work proposed by City or Developers.	THESL	THESI
Lab Services	Equipment Testing Services (Street Lighting division of THESI).	THESL	THESI
Permits and Attachments	Inspection charges for third party requests for attachments to Street Lighting poles.	THESL	THESI
Pole Rental	Attach fibre optic cable to street light pole where there are no ducts below ground.	THESL	THTI
Transfer of SL Attachments and Conductors	As part of LDC Conversion program, LDC will transfer or install SL fixtures and/or conductors to LDC transferred pole.	THESL	THESI
Warehouse storage and material issuance	Maintain stock supplies in warehouse and issue materials.	THESL	THESI

Shared Services Inventory

Service	Service Definition	Service Provider Company	Service Receiver Company
Wireless	Centralized handling of cellular phone charges distributed to affiliates.	THESL	THC
Wireless	Centralized handling of cellular phone charges distributed to affiliates.	THESL	THESI
Wireless	Centralized handling of cellular phone charges distributed to affiliates.	THESL	THTI
Street Light Transfers	To relocate street light assets embedded in our plant to accommodate planned capital projects	THESL	THESI

SERVICE AGREEMENT

THIS MEMORANDUM OF AGREEMENT made as of January 1, 2007.

BETWEEN:

Toronto Hydro Corporation ("THC")

and

Toronto Hydro-Electric System Limited ("Affiliate")

WHEREAS Affiliate desires THC to provide the Shared Services to it and THC wishes to provide the Shared Services, all upon the terms and conditions set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, THC and Affiliate (together, the "Parties") agree as follows:

1. PURPOSE

1.1 The purpose of this Agreement is to describe the Shared Services to be provided by THC to Affiliate, the charges to be made to Affiliate for such Shared Services, and the working relationship between THC and Affiliate relating to such Shared Services.

2. DEFINITIONS AND INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

(a) "Affiliate Relationships Code" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board on April 1, 1999, including any and all amendments or revisions thereto;

(b) "Agreement" means this Service Level Agreement for Shared Services and all instruments supplemental to it or in amendment or confirmation of it;

(c) "Term" shall have the meaning prescribed to it in Section 3.1 of this Agreement;

(d) "Parties" means THC and Affiliate collectively, and "Party" means any one of them;

(e) "Representatives" means any employee, agent, or subcontractor, of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4 of this Agreement;

(f) "Transfer Price(s)" shall have the meaning prescribed to it in Section 5 of this Agreement;

(g) "Shared Services" shall have the meaning prescribed to it in Section 4.1 of this Agreement.

2.2 Unless the context of this Agreement requires otherwise, the singular number shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form an integral part of this Agreement:

Schedule 1	Governance
Schedule 2	Legal Services
Schedule 3	Finance
Schedule 4	Communication & Public Affairs
Schedule 5	Environment, Health & Safety
Schedule 6	Organizational Effectiveness

3. TERM AND TERMINATION

3.1 The parties agree that, notwithstanding any provision contained therein, the Service Agreement made between them as of January 1, 2006 is terminated effective December 31, 2006.

3.2 This Agreement shall commence as of January 1, 2007 and will remain in effect until terminated by either Party, in whole or in part, upon no less than sixty (60) days' written notice to the other Party ("Term"); provided that in the event of default in performance of any material covenant in this Agreement, including Section 13.2, the non-defaulting Party shall be entitled to terminate the Agreement on no less than fourteen (14) days written notice to the defaulting Party. Any partial termination of the Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination; provided that the Parties shall make any adjustments required to insure that the Transfer Prices remain consistent with the Affiliate Relationships Code.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, THC shall provide Affiliate with the services listed in Schedules "1" through "6" hereto and any additional services required by Affiliate from time to time (collectively, the "Shared Services"). Any additional Shared Services required by Affiliate shall be provided by THC at mutually agreed upon terms, conditions and Transfer Prices, provided however that such terms, conditions and Transfer Prices shall be consistent with the requirements of the Affiliate Relationships Code.

4.2 THC shall provide the Shared Services at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

4.3 Subject to Sections 4.4 and 4.5 hereof, THC shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The parties agree that THC shall

be acting as the agent of Affiliate in procuring the delivery of such Shared Services of the Affiliates.

4.4 Where THC has contracted with a third party to provide part or all of the Shared Services pursuant to Section 4.3 above, Affiliate shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 This Agreement shall be deemed to be an exclusive service agreement as between THC and Affiliate, and Affiliate shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by THC.

4.6 No employee shall be shared between THC and the Affiliate; provided that an employee may be transferred or seconded from THC to the Affiliate or from the Affiliate to THC with the prior written approval of the Manager or Vice President of the relevant departments of THC and the Affiliate. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 THC shall bear all costs incurred, and all risk involved, in delivering the Shared Services to the Affiliate.

5. TRANSFER PRICING

5.1 All Shared Services provided by THC or its Representatives will be charged to Affiliate at the transfer prices determined in accordance with the Affiliate Relationships Code and set out in the attached Schedules (the "Transfer Price" or "Transfer Prices", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which the Affiliate shall also pay to THC.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary in order to ensure that the Transfer Prices remain consistent with the requirements of the Affiliate Relationships Code.

5.3 THC shall render to Affiliate on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to THC in respect of each of the Shared Services provided during the previous calendar month and the amount of any taxes which Affiliate has an obligation to pay.

5.4 Affiliate shall, no later than forty-five days after receipt of a THC invoice, or if such day is not a business day, the immediately preceding business day, render to THC, by any acceptable method agreed to by the Parties, the amount due THC as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Affiliate pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For THC: Jean Sebastian Couillard
Telephone: 416.542.3166
Fax: 416.542.2662

For Affiliate: Bob King
Telephone: 416.542.2611
Fax: 416.542.2833

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their best efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Presidents of each of the Parties. The parties agree to use their best efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. **"Confidential Information"** means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "Disclosing Party") to the other party (the "Recipient") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer and supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

13.2 THC shall comply at all time with the data management and data access protocols implemented by the Affiliate to protect access to Confidential Information.

IN WITNESS WHEREOF, the Parties have executed this agreement effective as of the date first above written as attested by the hands of their respective officers duly authorized in that behalf:

TORONTO HYDRO CORPORATION

Per: _____
Jean Sebastian Couillard
Chief Financial Officer

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Anthony Haines
President

SCHEDULES FOR SERVICE LEVEL AGREEMENT BETWEEN

Toronto Hydro Corporation
and
Toronto Hydro-Electric System Limited

Schedule	**Service Area**	**Page**
Schedule 1	Governance	2
Schedule 2	Legal Services	3
Schedule 3	Finance	4
Schedule 4	Communications & Public Affairs	5
Schedule 5	Environment, Health & Safety	6
Schedule 6	Organizational Effectiveness	7

SCHEDULE 1

SERVICE AREA: **Governance**

REF.	SECTION	COST
GOV1.0	Leadership	$785,784
GOV2.0	Strategic Direction	$74,875

SCHEDULE 2

SERVICE AREA: **Legal Services**

REF.	SECTION	COST
LGL1.0	Legal Services	$399,302
LGL4.0	Legal Strategic Direction and Leadership	$296,772

SCHEDULE 3

SERVICE AREA: **Finance**

REF.	SECTION	COST
FIN4.0	Corporate Financial Reporting	$1,133,385
FIN8.0	Business Planning	$562,585
FIN9.0 FIN10.0	Financial Planning & Reporting	$367,423
FIN12.0	Corporate Tax	$594,487
FIN14.0	Finance Stewardship	$226,410
FIN16.0	Internal Audits and Internal Control Certification	$1,333,945

SCHEDULE 4

SERVICE AREA: **Communications & Public Affairs**

REF.	SECTION	COST
CPA2.0	External Communications	$31,207
CPA5.0	Strategic Direction, Leadership and Communication	$138,598

SCHEDULE 5

SERVICE AREA: **Environment, Health & Safety**

REF.	SECTION	COST
EHS7.0	Strategic Direction and Leadership	$409,823

SCHEDULE 6

SERVICE AREA: **Organizational Effectiveness**

REF.	SECTION	COST
OE27.0	Strategic Direction and Leadership	$622,240

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Redacted

SERVICE AGREEMENT

THIS MEMORANDUM OF AGREEMENT made as of January 1, 2007.

BETWEEN:

Toronto Hydro Energy Services Inc. ("THESI")

and

Toronto Hydro-Electric System Limited ("Affiliate")

WHEREAS Affiliate desires THESI to provide the Shared Services to it and THESI wishes to provide the Shared Services, all upon the terms and conditions set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, THESI and Affiliate (together, the "Parties") agree as follows:

1. PURPOSE

1.1 The purpose of this Agreement is to describe the Shared Services to be provided by THESI to Affiliate, the charges to be made to Affiliate for such Shared Services, and the working relationship between THESI and Affiliate relating to such Shared Services.

2. DEFINITIONS AND INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

(a) "Affiliate Relationships Code" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board on April 1, 1999, including any and all amendments or revisions thereto;

(b) "Agreement" means this Service Level Agreement for Shared Services and all instruments supplemental to it or in amendment or confirmation of it;

(c) "Term" shall have the meaning prescribed to it in Section 3.1 of this Agreement;

(d) "Parties" means THESI and Affiliate collectively, and "Party" means any one of them;

(e) "Representatives" means any employee, agent, or subcontractor, of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4 of this Agreement;

(f) "Transfer Price(s)" shall have the meaning prescribed to it in Section 5 of this Agreement;

(g) "Shared Services" shall have the meaning prescribed to it in Section 4.1 of this Agreement.

2.2 Unless the context of this Agreement requires otherwise, the singular number shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form an integral part of this Agreement:

Schedule 1 Internet

3. TERM AND TERMINATION

3.1 The parties agree that, notwithstanding any provision contained therein, the Service Agreement made between them as of January 1, 2006 is terminated effective December 31, 2006.

3.2 This Agreement shall commence as of January 1, 2007 and will remain in effect until terminated by either Party, in whole or in part, upon no less than sixty (60) days' written notice to the other Party ("Term"); provided that in the event of default in performance of any material covenant in this Agreement, including Section 13.2, the non-defaulting Party shall be entitled to terminate the Agreement on no less than fourteen (14) days written notice to the defaulting Party. Any partial termination of the Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination; provided that the Parties shall make any adjustments required to insure that the Transfer Prices remain consistent with the Affiliate Relationships Code.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, THESI shall provide Affiliate with the services listed in Schedule "1" hereto and any additional services required by Affiliate from time to time (collectively, the "Shared Services"). Any additional Shared Services required by Affiliate shall be provided by THESI at mutually agreed upon terms, conditions and Transfer Prices, provided however that such terms, conditions and Transfer Prices shall be consistent with the requirements of the Affiliate Relationships Code.

4.2 THESI shall provide the Shared Services at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

4.3 Subject to Sections 4.4 and 4.5 hereof, THESI shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The parties agree that THESI shall be acting as the agent of Affiliate in procuring the delivery of such Shared Services of the Affiliates.

4.4 Where THESI has contracted with a third party to provide part or all of the Shared Services pursuant to Section 4.3 above, Affiliate shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 This Agreement shall be deemed to be an exclusive service agreement as between THESI and Affiliate, and Affiliate shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by THESI.

4.6 No employee shall be shared between THESI and the Affiliate; provided that an employee may be transferred or seconded from THESI to the Affiliate or from the Affiliate to THESI with the prior written approval of the Manager or Vice President of the relevant departments of THESI and the Affiliate. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 THESI shall bear all costs incurred, and all risk involved, in delivering the Shared Services to the Affiliate.

5. TRANSFER PRICING

5.1 All Shared Services provided by THESI or its Representatives will be charged to Affiliate at the transfer prices determined in accordance with the Affiliate Relationships Code and set out in the attached Schedules (the "Transfer Price" or "Transfer Prices", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which the Affiliate shall also pay to THESI.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary in order to ensure that the Transfer Prices remain consistent with the requirements of the Affiliate Relationships Code.

5.3 THESI shall render to Affiliate on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to THESI in respect of each of the Shared Services provided during the previous calendar month and the amount of any taxes which Affiliate has an obligation to pay.

5.4 Affiliate shall, no later than forty-five days after receipt of a THESI invoice, or if such day is not a business day, the immediately preceding business day, render to THESI, by any acceptable method agreed to by the Parties, the amount due THESI as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Affiliate pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For THESI: Chris Tyrrell
Telephone: 416.640.9708
Fax: 416.542.2511

For Affiliate: Bob King
Telephone: 416.542.2611
Fax: 416.542.2833

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their best efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Presidents of each of the Parties. The parties agree to use their best efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. **"Confidential Information"** means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "Disclosing Party") to the other party (the "Recipient") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer and supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

13.2 THC shall comply at all time with the data management and data access protocols implemented by the Affiliate to protect access to Confidential Information.

IN WITNESS WHEREOF, the Parties have executed this agreement effective as of the date first above written as attested by the hands of their respective officers duly authorized in that behalf:

TORONTO HYDRO ENERGY SERVICES INC.

Per: _____
Chris Tyrell
President

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Anthony Haines
President

SCHEDULES FOR SERVICE LEVEL AGREEMENT BETWEEN

Toronto Hydro Energy Services Inc.
and
Toronto Hydro-Electric System Limited

Schedule	Service Area	Page
Schedule 1	Facilities	2

SCHEDULE 1

SERVICE AREA: **Facilities**

ITEM	SECTION	COST
1	SCADA Equipment Space	[redacted]

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SERVICE AGREEMENT

THIS MEMORANDUM OF AGREEMENT made as of January 1, 2007.

BETWEEN:

Toronto Hydro-Electric System Limited ("THESL")

and

Toronto Hydro Corporation ("Affiliate")

WHEREAS Affiliate desires THESL to provide the Shared Services to it and THESL wishes to provide the Shared Services, all upon the terms and conditions set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, THESL and Affiliate (together, the "Parties") agree as follows:

1. PURPOSE

1.1 The purpose of this Agreement is to describe the Shared Services to be provided by THESL to Affiliate, the charges to be made to Affiliate for such Shared Services, and the working relationship between THESL and Affiliate relating to such Shared Services.

2. DEFINITIONS AND INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

(a) "Affiliate Relationships Code" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board on April 1, 1999, including any and all amendments or revisions thereto;

(b) "Agreement" means this Service Level Agreement for Shared Services and all instruments supplemental to it or in amendment or confirmation of it;

(c) "Term" shall have the meaning prescribed to it in Section 3.1 of this Agreement;

(d) "Parties" means THESL and Affiliate collectively, and "Party" means any one of them;

(e) "Representatives" means any employee, agent, or subcontractor, of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4 of this Agreement;

(f) "Transfer Price(s)" shall have the meaning prescribed to it in Section 5 of this Agreement;

(g) "Shared Services" shall have the meaning prescribed to it in Section 4.1 of this Agreement.

2.2 Unless the context of this Agreement requires otherwise, the singular number shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form an integral part of this Agreement:

Schedule 1	Finance
Schedule 2	Treasury, Rates & Regulatory Affairs
Schedule 3	Communications & Public Affairs
Schedule 4	Information Technology & Services
Schedule 5	Procurement
Schedule 6	Legal
Schedule 7	Organizational Effectiveness
Schedule 8	Facilities and Asset Management
Schedule 8A	Facilities and Asset Management – Facilities & Fleet

3. TERM AND TERMINATION

3.1 The parties agree that, notwithstanding any provision contained therein, the Service Agreement made between them as of January 1, 2006 is terminated effective December 31, 2006.

3.2 This Agreement shall commence as of January 1, 2007 and will remain in effect until terminated by either Party, in whole or in part, upon no less than sixty (60) days' written notice to the other Party ("Term"); provided that in the event of default in performance of any material covenant in this Agreement, including Section 13.2, the non-defaulting Party shall be entitled to terminate the Agreement on no less than fourteen (14) days written notice to the defaulting Party. Any partial termination of the Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination; provided that the Parties shall make any adjustments required to insure that the Transfer Prices remain consistent with the Affiliate Relationships Code.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, THESL shall provide Affiliate with the services listed in Schedules "1" through "8A" hereto and any additional services required by Affiliate from time to time (collectively, the "Shared Services"). Any additional Shared Services required by Affiliate shall be provided by THESL at mutually agreed upon terms, conditions and Transfer Prices, provided however that such terms, conditions and Transfer Prices shall be consistent with the requirements of the Affiliate Relationships Code.

4.2 THESL shall provide the Shared Services at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

4.3 Subject to Sections 4.4 and 4.5 hereof, THESL shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The parties agree that THESL shall be acting as the agent of Affiliate in procuring the delivery of such Shared Services of the Affiliates.

4.4 Where THESL has contracted with a third party to provide part or all of the Shared Services pursuant to Section 4.3 above, Affiliate shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 This Agreement shall be deemed to be an exclusive service agreement as between THESL and Affiliate, and Affiliate shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by THESL.

4.6 No employee shall be shared between THESL and the Affiliate; provided that an employee may be transferred or seconded from THESL to the Affiliate or from the Affiliate to THESL with the prior written approval of the Manager or Vice President of the relevant departments of THESL and the Affiliate. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 THESL shall bear all costs incurred, and all risk involved, in delivering the Shared Services to the Affiliate.

5. TRANSFER PRICING

5.1 All Shared Services provided by THESL or its Representatives will be charged to Affiliate at the transfer prices determined in accordance with the Affiliate Relationships Code and set out in the attached Schedules (the "Transfer Price" or "Transfer Prices", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which the Affiliate shall also pay to THESL.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary in order to ensure that the Transfer Prices remain consistent with the requirements of the Affiliate Relationships Code.

5.3 THESL shall render to Affiliate on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to THESL in respect of each of the Shared Services provided during the previous calendar month and the amount of any taxes which Affiliate has an obligation to pay.

5.4 Affiliate shall, no later than forty-five days after receipt of a THESL invoice, or if such day is not a business day, the immediately preceding business day, render to THESL, by any acceptable method agreed to by the Parties, the amount due THESL as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Affiliate pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For THESL: Bob King
Telephone: 416.542.2611
Fax: 416.542.2833

For Affiliate: Jean-Sebastian Couillard
Telephone: 416.542.3166
Fax: 416.542.2663

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their best efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Presidents of each of the Parties. The parties agree to use their best efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. **"Confidential Information"** means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "Disclosing Party") to the other party (the "Recipient") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer and supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

13.2 THC shall comply at all time with the data management and data access protocols implemented by the Affiliate to protect access to Confidential Information.

IN WITNESS WHEREOF, the Parties have executed this agreement effective as of the date first above written as attested by the hands of their respective officers duly authorized in that behalf:

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Anthony Haines
President

TORONTO HYDRO CORPORATION

Per: _____
Jean-Sebastian Couillard
Chief Financial Officer

SCHEDULES FOR SERVICE LEVEL AGREEMENT BETWEEN

Toronto Hydro-Electric System Limited
and
Toronto Hydro Corporation

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Schedule 1	Finance	2
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Schedule 8	Facilities and Asset Management	9
Schedule 8A	Facilities and Asset Management – Facilities & Fleet	10

SCHEDULE 1

SERVICE AREA: **Finance**

REF.	SECTION	COST
FIN2.0	Payroll	$17,620
FIN5.0	Accounts Payable	$63,988

SCHEDULE 2

SERVICE AREA: **Treasury, Rates & Regulatory Affairs**

REF.	SECTION	COST
TRR14.0 - TRR17.0 TRR19.0 - TRR20.0	Cash Management; Credit Risk Management; Long-Term Debt Management and Investor Relations; Financing Strategy; Monthly Accounting/Reporting	$407,731

SCHEDULE 3

SERVICE AREA: **Communications & Public Affairs**

REF.	SECTION	COST
CPA2.0	External Communications	$149,973
CPA3.0	Community Involvement and Corporate Social Responsibility	$25,840

SCHEDULE 4

SERVICE AREA: **Information Technology & Services**

REF.	SECTION	COST
ITS2.0	IT Management Services	$81,060
ITS1.0, ITS3.0 - ITS7.0	Client Services; Operations; Network/Telephony; Strategy & Governance; Application Support	$269,947

SCHEDULE 5

SERVICE AREA: **Procurement**

REF.	SECTION	COST
PRC1.0	Acquisition of Goods & Services	$38,544

SCHEDULE 6

SERVICE AREA: **Legal**

REF.	SECTION	COST
LGL1.0	Legal Services	$521,938

SCHEDULE 7

SERVICE AREA: **Organizational Effectiveness**

REF.	SECTION	COST
OE1-OE9, OE17, 19	Disability Case Management; Attendance Management Program; Administer and Manage All Leaves; Development and Maintenance of HRIS System; Administer Benefits Program - Employees & Retirees; Manage Total Compensation Program (Job Evaluation/Salary Administration/Variable Pay); Manage Retirement Program; Training & Education on Compensation & Benefits Topics; Manage Benefit Programs – Employees & Retirees	$19,489
OE10-16, 18, 20	Labour Relations; Employee Relations; Deliver Training on Labour/Employee Relations Topics; Legal Compliance; HR Practices and Procedures; Conduct Recruitment, Selection & Orientation – Full-time, Temporary, Internal & External; Administer Student & Intern Employment Programs; Process Voluntary Termination; Engage Contingent Personnel	$31,992
OE21-25	Training and Development; Leadership Development & Succession Planning; Corporate Performance Management Support; Performance Management; Change Management	$35,203
OE26	Project Management Support Office	$12,070

SCHEDULE 8

SERVICE AREA: **Facilities and Asset Management**

REF.	SECTION	COST
FAM1.0 - FAM7.0	Operation & Maintenance; Real Estate; Human & Environmental Factors; Planning and Project Management; Manage Facility Function; Quality Assessment & Innovation; Investment Recovery (See Schedule 8A)	$486,336
FAM8.0 - FAM17.0	Fleet Management & Repair; Wash Vehicles & Equipment; Fleet Vehicle & Equipment Asset Management; Inventory Management; Legislative Compliance; Licences, Permits; Fleet Parking; Driver Training and Licence Management; Centralized Tool Crib Services (See Schedule 8A)	$78,563

SCHEDULE 8A

SERVICE AREA: **Facilities and Asset Management**

FACILITIES

ITEM	LOCATION	COST
1	14 Carlton	$486,336

FLEET

# OF VEHICLES	VEHICLE CLASS	COST
6	Executive Vehicle	$78,563

Redacted

SERVICE AGREEMENT

THIS MEMORANDUM OF AGREEMENT made as of January 1, 2007.

BETWEEN:

Toronto Hydro-Electric System Limited ("THESL")

and

Toronto Hydro Energy Services Inc. ("Affiliate")

WHEREAS Affiliate desires THESL to provide the Shared Services to it and THESL wishes to provide the Shared Services, all upon the terms and conditions set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, THESL and Affiliate (together, the "Parties") agree as follows:

1. PURPOSE

1.1 The purpose of this Agreement is to describe the Shared Services to be provided by THESL to Affiliate, the charges to be made to Affiliate for such Shared Services, and the working relationship between THESL and Affiliate relating to such Shared Services.

2. DEFINITIONS AND INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

(a) "Affiliate Relationships Code" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board on April 1, 1999, including any and all amendments or revisions thereto;

(b) "Agreement" means this Service Level Agreement for Shared Services and all instruments supplemental to it or in amendment or confirmation of it;

(c) "Term" shall have the meaning prescribed to it in Section 3.1 of this Agreement;

(d) "Parties" means THESL and Affiliate collectively, and "Party" means any one of them;

(e) "Representatives" means any employee, agent, or subcontractor, of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4 of this Agreement;

(f) "Transfer Price(s)" shall have the meaning prescribed to it in Section 5 of this Agreement;

(g) "Shared Services" shall have the meaning prescribed to it in Section 4.1 of this Agreement.

2.2 Unless the context of this Agreement requires otherwise, the singular number shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form an integral part of this Agreement:

Schedule 1	Environment, Health & Safety
Schedule 2	Treasury, Rates & Regulatory Affairs
Schedule 3	Finance
Schedule 4	Communications & Public Affairs
Schedule 5	Information Technology & Services
Schedule 6	Procurement
Schedule 7	Legal
Schedule 8	Facilities and Asset Management
Schedule 8A	Facilities and Asset Management – Facilities & Fleet
Schedule 9	Streetlight Work for Planned or Demand Capital Projects

3. TERM AND TERMINATION

3.1 The parties agree that, notwithstanding any provision contained therein, the Service Agreement made between them as of January 1, 2006 is terminated effective December 31, 2006.

3.2 This Agreement shall commence as of January 1, 2007 and will remain in effect until terminated by either Party, in whole or in part, upon no less than sixty (60) days' written notice to the other Party ("Term"); provided that in the event of default in performance of any material covenant in this Agreement, including Section 13.2, the non-defaulting Party shall be entitled to terminate the Agreement on no less than fourteen (14) days written notice to the defaulting Party. Any partial termination of the Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination; provided that the Parties shall make any adjustments required to insure that the Transfer Prices remain consistent with the Affiliate Relationships Code.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, THESL shall provide Affiliate with the services listed in Schedules "1" through "9" hereto and any additional services required by Affiliate from time to time (collectively, the "Shared Services"). Any additional Shared Services required by Affiliate shall be provided by THESL at mutually agreed upon terms, conditions and Transfer Prices, provided however that such terms, conditions and Transfer Prices shall be consistent with the requirements of the Affiliate Relationships Code.

4.2 THESL shall provide the Shared Services at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

4.3 Subject to Sections 4.4 and 4.5 hereof, THESL shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The parties agree that THESL shall be acting as the agent of Affiliate in procuring the delivery of such Shared Services of the Affiliates.

4.4 Where THESL has contracted with a third party to provide part or all of the Shared Services pursuant to Section 4.3 above, Affiliate shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 This Agreement shall be deemed to be an exclusive service agreement as between THESL and Affiliate, and Affiliate shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by THESL.

4.6 No employee shall be shared between THESL and the Affiliate; provided that an employee may be transferred or seconded from THESL to the Affiliate or from the Affiliate to THESL with the prior written approval of the Manager or Vice President of the relevant departments of THESL and the Affiliate. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 THESL shall bear all costs incurred, and all risk involved, in delivering the Shared Services to the Affiliate.

5. TRANSFER PRICING

5.1 All Shared Services provided by THESL or its Representatives will be charged to Affiliate at the transfer prices determined in accordance with the Affiliate Relationships Code and set out in the attached Schedules (the "Transfer Price" or "Transfer Prices", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which the Affiliate shall also pay to THESL.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary in order to ensure that the Transfer Prices remain consistent with the requirements of the Affiliate Relationships Code.

5.3 THESL shall render to Affiliate on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to THESL in respect of each of the Shared Services provided during the previous calendar month and the amount of any taxes which Affiliate has an obligation to pay.

5.4 Affiliate shall, no later than forty-five days after receipt of a THESL invoice, or if such day is not a business day, the immediately preceding business day, render to THESL, by any acceptable method agreed to by the Parties, the amount due THESL as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of

the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Affiliate pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For THESL: Bob King
Telephone: 416.542.2611
Fax: 416.542.2833

For Affiliate: Chris Tyrrell
Telephone: 416.640.9708
Fax: 416.542.2511

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their best efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Presidents of each of the Parties. The parties agree to use their best efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. **"Confidential Information"** means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "Disclosing Party") to the other party (the "Recipient") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer and supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

13.2 THC shall comply at all time with the data management and data access protocols implemented by the Affiliate to protect access to Confidential Information.

IN WITNESS WHEREOF, the Parties have executed this agreement effective as of the date first above written as attested by the hands of their respective officers duly authorized in that behalf:

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Anthony Haines
President

TORONTO HYDRO ENERGY SERVICES INC.

Per: _____
Chris Tyrrell
President

SCHEDULES FOR SERVICE LEVEL AGREEMENT BETWEEN

Toronto Hydro-Electric System Limited
and
Toronto Hydro Energy Services Inc.

Schedule	Service Area	Page
Schedule 1	Environment, Health & Safety	2
Schedule 2	Treasury, Rates & Regulatory Affairs	3
Schedule 3	Finance	4
Schedule 4	Communications & Public Affairs	5
Schedule 5	Information Technology & Services	6
Schedule 6	Procurement	7
Schedule 7	Legal	8
Schedule 8	Facilities and Asset Management	9
Schedule 8A	Facilities and Asset Management – Facilities & Fleet	10
Schedule 9	Street Light Work for Planned or Demand Capital Projects	11

SCHEDULE 1

SERVICE AREA: **Environment, Health & Safety**

REF.	SECTION	COST
EHS2.0, EHS4.0, EHS5.0	Safety: Environment, Health & Safety Management System; Environment, Health & Safety Training; Accident/Incident Investigations	[redacted]
EHS1.0	Occupational Health - Health Services	[redacted]
EHS4.0	Environmental - Environment, Health & Safety Training	[redacted]
EHS6.0	WSIB Claims Management Administration	[redacted]

SCHEDULE 2

SERVICE AREA: **Treasury, Rates & Regulatory Affairs**

REF.	SECTION	COST
TRR14.0 - TRR17.0 TRR19.0 - TRR20.0	Cash Management; Credit Risk Management; Long-term Debt Management and Investor Relations; Financing Strategy; Monthly Accounting/Reporting	[redacted]

SCHEDULE 3

SERVICE AREA: **Finance**

REF.	SECTION	COST
FIN2.0	Payroll	[redacted]
FIN5.0	Accounts Payable	[redacted]

SCHEDULE 4

SERVICE AREA: **Communications & Public Affairs**

REF.	SECTION	COST
CPA3.0	Community Involvement and Corporate Social Responsibility	$[redacted]

SCHEDULE 5

SERVICE AREA: **Information Technology & Services**

REF.	SECTION	COST
ITS2.0	IT Management Services	$[redacted]
ITS1.0, ITS3.0 - ITS7.0	Client Services; Operations; Network/Telephony; Strategy & Governance; Application Support	$[redacted]

SCHEDULE 6

SERVICE AREA: **Procurement**

REF.	SECTION	COST
PRC1.0	Acquisition of Goods & Services	[redacted]

SCHEDULE 7

SERVICE AREA: **Legal**

REF.	SECTION	COST
LGL1.0	Legal Services	[redacted]
LGL3.0	Claims Administration	[redacted]

SCHEDULE 8

SERVICE AREA: **Facilities and Asset Management**

REF.	SECTION	COST
FAM1.0 - FAM7.0	Operation & Maintenance; Real Estate; Human & Environmental Factors; Planning and Project Management; Manage Facility Function; Quality Assessment & Innovation; Investment Recovery (See Schedule 8A)	[redacted]
FAM8.0 - FAM17.0	Fleet Management & Repair; Wash Vehicles & Equipment; Fleet Vehicle & Equipment Asset Management; Inventory Management; Legislative Compliance; Licences, Permits; Fleet Parking; Driver Training and Licence Management; Centralized Tool Crib Services (See Schedule 8A)	[redacted]

SCHEDULE 8A

SERVICE AREA: **Facilities and Asset Management**

FACILITIES

ITEM	LOCATION	COST
1	920 Markham	[redacted]
2	Wiltshire	[redacted]

FLEET

# OF VEHICLES	VEHICLE CLASS	COST
1	OA - Car Sub Compact	[redacted]
1	OB - Car Compact	[redacted]
1	1B - Pickup F-Size-Reg Cab 2501 +Kg	[redacted]
2	1C - Pickup F-Size Crew Cab 2501 +KG	[redacted]
1	2F - Van Cube More Than 4600 Kg+	[redacted]
1	7B - Pole Trailer	[redacted]
9	5A - Single Bucket Squirt Boom	[redacted]
2	5B - Single Bucket Conventional Boom	[redacted]
1	5D - Single Bucket Van Mounted	[redacted]
1	6B - Derrick Small Ie. K10-K14	[redacted]
1	Executive Vehicle	[redacted]

SCHEDULE 9

SERVICE AREA: **Street Light Work for Planned or Demand Capital Projects**

ITEM	SERVICE DESCRIPTION TYPE	COST	U.O.M.
1	Transfer/Remove existing luminaries and bracket	[redacted]	Pole
2	Install new luminaries and bracket/make connection	[redacted]	Pole
3	Install overhead street light cable	[redacted]	Span
4	Remove overhead street light cable	[redacted]	Span
5	Install street lighting relay/disconnect control	[redacted]	Relay
6	Remove street lighting relay/disconnect control	[redacted]	Relay
7	Install/Remove underground street light cable	[redacted]	Metre
8	Install/Transfer/Remove street light dip on pole	[redacted]	Dip
CIVIL WORK			
9	Exclusive work for street lighting	[redacted]	
10	Joint trench cost sharing (road allowance)	[redacted]	
11	Joint trench cost sharing (road crossing)	[redacted]	
12	Joint tunneling costs sharing (road allowance)	[redacted]	
13	Install DB street light duct (road allowance)	[redacted]	
14	Install CE street light duct (road crossing)	[redacted]	

Notes:
1. Charges do not include time and equipment for Crew Leaders
2. In the event of a 3-man crew, the 2-man crew rates will remain in effect
3. A[redacted]dministrative cost will be applicable to all unit prices
4. UPCMS – Unit Price Contract Management Systems
5. SDP – Standard Design Practice

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SERVICE AGREEMENT

THIS MEMORANDUM OF AGREEMENT made as of January 1, 2007.

BETWEEN:

Toronto Hydro-Electric System Limited ("THESL")

and

Toronto Hydro Telecom Inc. ("Affiliate")

WHEREAS Affiliate desires THESL to provide the Shared Services to it and THESL wishes to provide the Shared Services, all upon the terms and conditions set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, THESL and Affiliate (together, the "Parties") agree as follows:

1. PURPOSE

1.1 The purpose of this Agreement is to describe the Shared Services to be provided by THESL to Affiliate, the charges to be made to Affiliate for such Shared Services, and the working relationship between THESL and Affiliate relating to such Shared Services.

2. DEFINITIONS AND INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

(a) "Affiliate Relationships Code" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board on April 1, 1999, including any and all amendments or revisions thereto;

(b) "Agreement" means this Service Level Agreement for Shared Services and all instruments supplemental to it or in amendment or confirmation of it;

(c) "Term" shall have the meaning prescribed to it in Section 3.1 of this Agreement;

(d) "Parties" means THESL and Affiliate collectively, and "Party" means any one of them;

(e) "Representatives" means any employee, agent, or subcontractor, of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4 of this Agreement;

(f) "Transfer Price(s)" shall have the meaning prescribed to it in Section 5 of this Agreement;

(g) "Shared Services" shall have the meaning prescribed to it in Section 4.1 of this Agreement.

2.2 Unless the context of this Agreement requires otherwise, the singular number shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form an integral part of this Agreement:

Schedule 1	Environment, Health & Safety
Schedule 2	Treasury, Rates & Regulatory Affairs
Schedule 3	Finance
Schedule 4	Communications & Public Affairs
Schedule 5	Information Technology & Services
Schedule 6	Procurement
Schedule 7	Legal
Schedule 8	Facilities and Asset Management
Schedule 8A	Facilities and Asset Management – Facilities & Fleet

3. TERM AND TERMINATION

3.1 The parties agree that, notwithstanding any provision contained therein, the Service Agreement made between them as of January 1, 2006 is terminated effective December 31, 2006.

3.2 This Agreement shall commence as of January 1, 2007 and will remain in effect until terminated by either Party, in whole or in part, upon no less than sixty (60) days' written notice to the other Party ("Term"); provided that in the event of default in performance of any material covenant in this Agreement, including Section 13.2, the non-defaulting Party shall be entitled to terminate the Agreement on no less than fourteen (14) days written notice to the defaulting Party. Any partial termination of the Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination; provided that the Parties shall make any adjustments required to insure that the Transfer Prices remain consistent with the Affiliate Relationships Code.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, THESL shall provide Affiliate with the services listed in Schedules "1" through "8A" hereto and any additional services required by Affiliate from time to time (collectively, the "Shared Services"). Any additional Shared Services required by Affiliate shall be provided by THESL at mutually agreed upon terms, conditions and Transfer Prices, provided however that such terms, conditions and Transfer Prices shall be consistent with the requirements of the Affiliate Relationships Code.

4.2 THESL shall provide the Shared Services at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

4.3 Subject to Sections 4.4 and 4.5 hereof, THESL shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The parties agree that THESL shall be acting as the agent of Affiliate in procuring the delivery of such Shared Services of the Affiliates.

4.4 Where THESL has contracted with a third party to provide part or all of the Shared Services pursuant to Section 4.3 above, Affiliate shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 This Agreement shall be deemed to be an exclusive service agreement as between THESL and Affiliate, and Affiliate shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by THESL.

4.6 No employee shall be shared between THESL and the Affiliate; provided that an employee may be transferred or seconded from THESL to the Affiliate or from the Affiliate to THESL with the prior written approval of the Manager or Vice President of the relevant departments of THESL and the Affiliate. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 THESL shall bear all costs incurred, and all risk involved, in delivering the Shared Services to the Affiliate.

5. TRANSFER PRICING

5.1 All Shared Services provided by THESL or its Representatives will be charged to Affiliate at the transfer prices determined in accordance with the Affiliate Relationships Code and set out in the attached Schedules (the "Transfer Price" or "Transfer Prices", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which the Affiliate shall also pay to THESL.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary in order to ensure that the Transfer Prices remain consistent with the requirements of the Affiliate Relationships Code.

5.3 THESL shall render to Affiliate on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to THESL in respect of each of the Shared Services provided during the previous calendar month and the amount of any taxes which Affiliate has an obligation to pay.

5.4 Affiliate shall, no later than forty-five days after receipt of a THESL invoice, or if such day is not a business day, the immediately preceding business day, render to THESL, by any acceptable method agreed to by the Parties, the amount due THESL as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Affiliate pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For THESL: Bob King
Telephone: 416.542.2611
Fax: 416.542.2833

For Affiliate: David Dobbin
Telephone: 416.840.8740
Fax: 416.542.3362

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their best efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Presidents of each of the Parties. The parties agree to use their best efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. **"Confidential Information"** means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "Disclosing Party") to the other party (the "Recipient") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer and supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

13.2 THC shall comply at all time with the data management and data access protocols implemented by the Affiliate to protect access to Confidential Information.

IN WITNESS WHEREOF, the Parties have executed this agreement effective as of the date first above written as attested by the hands of their respective officers duly authorized in that behalf:

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Anthony Haines
President

TORONTO HYDRO TELECOM INC.

Per: _____
David Dobbin
President

SCHEDULES FOR SERVICE LEVEL AGREEMENT BETWEEN

Toronto Hydro-Electric System Limited
and
Toronto Hydro Telecom Inc.

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SCHEDULE 1

SERVICE AREA: **Environment, Health & Safety**

REF.	SECTION	COST
EHS2.0, EHS5.0	Safety: Environment, Health & Safety Management System; Accident/Incident Investigations	[redacted]
EHS1.0	Health Services - Occupational Health	[redacted]
EHS4.0	Environmental - Environment, Health & Safety Training	[redacted]
EHS6.0	WSIB Claims Management Administration	[redacted]

SCHEDULE 2

SERVICE AREA: **Treasury, Rates & Regulatory Affairs**

REF.	SECTION	COST
TRR14.0 - TRR17.0 TRR19.0 - TRR20.0	Cash Management; Credit Risk Management; Long-term Debt Management and Investor Relations; Financing Strategy; Monthly Accounting/Reporting	[redacted]

SCHEDULE 3

SERVICE AREA: **Finance**

REF.	SECTION	COST
FIN2.0	Payroll	[redacted]
FIN5.0	Accounts Payable	[redacted]

SCHEDULE 4

SERVICE AREA: **Communications & Public Affairs**

REF.	SECTION	COST
CPA3.0	Community Involvement and Corporate Social Responsibility	[redacted]

SCHEDULE 5

SERVICE AREA: **Information Technology & Services**

REF.	SECTION	COST
ITS2.0	IT Management Services	[redacted]
ITS1.0, ITS3.0 - ITS7.0	Client Services; Operations; Network/Telephony; Strategy & Governance; Application Support	[redacted]

SCHEDULE 6

SERVICE AREA: **Procurement**

REF.	SECTION	COST
PRC1.0	Acquisition of Goods & Services	[redacted]

SCHEDULE 7

SERVICE AREA: **Legal**

REF.	SECTION	COST
LGL1.0	Legal Services	[redacted]

SCHEDULE 8

SERVICE AREA: **Facilities and Asset Management**

REF.	SECTION	COST
FAM1.0 - FAM7.0	Operation & Maintenance; Real Estate; Human & Environmental Factors; Planning and Project Management; Manage Facility Function; Quality Assessment & Innovation; Investment Recovery (See Schedule 8A)	[redacted]
FAM8.0 - FAM17.0	Fleet Management & Repair; Wash Vehicles & Equipment; Fleet Vehicle & Equipment Asset Management; Inventory Management; Legislative Compliance; Licences, Permits; Fleet Parking; Driver Training and Licence Management; Centralized Tool Crib Services (See Schedule 8A)	[redacted]

SCHEDULE 8A

SERVICE AREA: **Facilities and Asset Management**

FACILITIES

ITEM	LOCATION	COST
1	5800 Yonge Street - 1st Floor	[redacted]
2A	14 Carlton - Basement	[redacted]
2B	14 Carlton - 1st Floor	[redacted]
3	10 Lupin	[redacted]

FLEET

# OF VEHICLES	VEHICLE CLASS	COST
6	2b - Van Cargo Mini Up to 2500 Kg	[redacted]

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Redacted

SERVICE AGREEMENT

THIS MEMORANDUM OF AGREEMENT made as of January 1, 2007.

BETWEEN:

Toronto Hydro Telecom Inc. ("THTI")

and

Toronto Hydro-Electric System Limited ("Affiliate")

WHEREAS Affiliate desires THTI to provide the Shared Services to it and THTI wishes to provide the Shared Services, all upon the terms and conditions set forth herein.

NOW THEREFORE in consideration of the mutual covenants and agreements herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, THTI and Affiliate (together, the "Parties") agree as follows:

1. PURPOSE

1.1 The purpose of this Agreement is to describe the Shared Services to be provided by THTI to Affiliate, the charges to be made to Affiliate for such Shared Services, and the working relationship between THTI and Affiliate relating to such Shared Services.

2. DEFINITIONS AND INTERPRETATION

2.1 As used in this Agreement, the following terms shall have the following meanings:

(a) "Affiliate Relationships Code" means the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board on April 1, 1999, including any and all amendments or revisions thereto;

(b) "Agreement" means this Service Level Agreement for Shared Services and all instruments supplemental to it or in amendment or confirmation of it;

(c) "Term" shall have the meaning prescribed to it in Section 3.1 of this Agreement;

(d) "Parties" means THTI and Affiliate collectively, and "Party" means any one of them;

(e) "Representatives" means any employee, agent, or subcontractor, of the Party in question, including without limitation any third party retained to perform any or all of the Shared Services pursuant to Section 4 of this Agreement;

(f) "Transfer Price(s)" shall have the meaning prescribed to it in Section 5 of this Agreement;

(g) "Shared Services" shall have the meaning prescribed to it in Section 4.1 of this Agreement.

2.2 Unless the context of this Agreement requires otherwise, the singular number shall include the plural and vice versa and any gender includes any other gender.

2.3 The following Schedules are attached to and form an integral part of this Agreement:

Schedule 1 Internet

3. TERM AND TERMINATION

3.1 The parties agree that, notwithstanding any provision contained therein, the Service Agreement made between them as of January 1, 2006 is terminated effective December 31, 2006.

3.2 This Agreement shall commence as of January 1, 2007 and will remain in effect until terminated by either Party, in whole or in part, upon no less than sixty (60) days' written notice to the other Party ("Term"); provided that in the event of default in performance of any material covenant in this Agreement, including Section 13.2, the non-defaulting Party shall be entitled to terminate the Agreement on no less than fourteen (14) days written notice to the defaulting Party. Any partial termination of the Agreement shall be evidenced by a written agreement as between the Parties specifying the specific Shared Services to be terminated, and the adjustment in Transfer Price pursuant to such partial termination; provided that the Parties shall make any adjustments required to insure that the Transfer Prices remain consistent with the Affiliate Relationships Code.

4. SHARED SERVICES

4.1 Subject to Section 4.5 of this Agreement, THTI shall provide Affiliate with the services listed in Schedule "1" hereto and any additional services required by Affiliate from time to time (collectively, the "Shared Services"). Any additional Shared Services required by Affiliate shall be provided by THTI at mutually agreed upon terms, conditions and Transfer Prices, provided however that such terms, conditions and Transfer Prices shall be consistent with the requirements of the Affiliate Relationships Code.

4.2 THTI shall provide the Shared Services at quality levels which are mutually acceptable to the parties. These levels shall be reviewed from time to time.

4.3 Subject to Sections 4.4 and 4.5 hereof, THTI shall have the right, in its sole discretion, to contract with a third party to deliver all or part of the Shared Services, provided however that such third party shall be capable of providing such Shared Services to the same or better quality levels than those set forth in Section 4.2. The parties agree that THTI shall be acting as the agent of Affiliate in procuring the delivery of such Shared Services of the Affiliates.

4.4 Where THTI has contracted with a third party to provide part or all of the Shared Services pursuant to Section 4.3 above, Affiliate shall pay the amount charged by such third party for the portion of the Shared Services delivered.

4.5 This Agreement shall be deemed to be an exclusive service agreement as between THTI and Affiliate, and Affiliate shall not have the right to provide itself, or retain a third party to provide, any of the Shared Services unless agreed to by THTI.

4.6 No employee shall be shared between THTI and the Affiliate; provided that an employee may be transferred or seconded from THTI to the Affiliate or from the Affiliate to THTI with the prior written approval of the Manager or Vice President of the relevant departments of THTI and the Affiliate. Such approval shall set forth the terms and conditions of such transfer including all appropriate measures required to preserve the confidentiality of customer information. When on a secondment or transfer, the employee will not provide any services whatsoever to the original company during the period of secondment or transfer.

4.7 THTI shall bear all costs incurred, and all risk involved, in delivering the Shared Services to the Affiliate.

5. TRANSFER PRICING

5.1 All Shared Services provided by THTI or its Representatives will be charged to Affiliate at the transfer prices determined in accordance with the Affiliate Relationships Code and set out in the attached Schedules (the "Transfer Price" or "Transfer Prices", collectively). The Transfer Prices do not include GST or any other taxes payable in respect of the Transfer Price, which the Affiliate shall also pay to THTI.

5.2 The Parties hereby agree and acknowledge that they shall renegotiate the Shared Services and Transfer Prices described in Schedules hereto at such times as necessary in order to ensure that the Transfer Prices remain consistent with the requirements of the Affiliate Relationships Code.

5.3 THTI shall render to Affiliate on or before the 15th day of each month (or such other time as may be agreed), an invoice setting forth the total amount due to THTI in respect of each of the Shared Services provided during the previous calendar month and the amount of any taxes which Affiliate has an obligation to pay.

5.4 Affiliate shall, no later than forty-five days after receipt of a THTI invoice, or if such day is not a business day, the immediately preceding business day, render to THTI, by any acceptable method agreed to by the Parties, the amount due THTI as set forth in the invoice. This Section 5.4 shall survive any termination of this Agreement or the expiry of the Term for a period of twelve (12) months from the date on which the last invoice is rendered to Affiliate pursuant to this Agreement.

6. NOTICES AND CONTACTS

6.1 Any notice or communication required as between the Parties pursuant to this Agreement shall be delivered to the following individuals, or to such other individual as either Party may stipulate by notice to the other:

For THTI: David Dobbin
Telephone: 416.840.8740
Fax: 416.542.3362

For Affiliate: Bob King
Telephone: 416.542.2611
Fax: 416.542.2833

7. AMENDMENTS

7.1 If at any time during the term of this Agreement the Parties deem it necessary or expedient to make any alteration or addition to this Agreement, they may do so by means of a written agreement between them which shall be supplemental and form part of this Agreement.

8. FURTHER ASSURANCES

8.1 The Parties agree that each of them shall, upon reasonable request of the other, do or cause to be done all further lawful acts, deeds and assurances whatever for the better performance of the terms and conditions of this Agreement.

9. SUCCESSORS AND ASSIGNS

9.1 This Agreement shall enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties, provided however that neither Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

10. SEVERABILITY

10.1 If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this Agreement shall continue in full force and effect.

11. COUNTERPARTS

11.1 This Agreement may be executed by the Parties in separate counterparts, each of which when so executed and delivered shall be an original, but all counterparts shall together constitute one and the same instrument.

12. DISPUTE RESOLUTION

12.1 The Parties will use their best efforts to resolve, at an operational level, any disputes which may arise concerning this Agreement. Any issues which remain unresolved for more than fifteen (15) days will be referred to the respective Presidents of each of the Parties. The parties agree to use their best efforts to resolve all disputes in a timely and professional manner utilizing a process appropriate to the issues involved.

13. CONFIDENTIALITY

13.1 Each party agrees not to disclose any Confidential Information to any person except those of its Representatives who have a need to know such Confidential Information in connection with this Agreement and who are informed of the confidential nature of the Confidential Information and who agree to be bound by the terms of this Section 13.1. The Recipient will not use any Confidential Information relating to the Disclosing Party for any purpose other than in connection with the performance of its obligations, or exercise of its rights, under this Agreement, and will exercise the same security measures normally exercised with respect to its own Confidential Information, and at a minimum a reasonable degree of care, to safeguard the Confidential Information from disclosure to anyone other than as permitted hereby. The provisions of this Section 13.1 shall survive termination of this Agreement. **"Confidential Information"** means all information, whether disclosed orally, in writing, or otherwise, designated as being confidential, which is disclosed by one party (the "Disclosing Party") to the other party (the "Recipient") relating to the business of the Disclosing Party or in connection with the subject matter of this Agreement and includes, but is not limited to, business, financial, and marketing information, plans and strategies, contractual, customer and supplier information, technical information related to hardware, software and firmware, and know-how, trade secrets and any other intellectual property rights, and the terms of this Agreement. Notwithstanding the foregoing, Confidential Information shall not include information which (i) now is, or hereafter properly becomes, generally available to the public other than as a result of disclosure in breach of this Agreement; (ii) is required to be disclosed in compliance with any applicable law, under order of a court of competent jurisdiction or other similar requirement of a governmental agency, so long as the Recipient provides the Disclosing Party with prior written notice of any required disclosure pursuant to such law, order or requirement and cooperates, to the extent permitted by law with the Disclosing Party in seeking an order eliminating or restricting the disclosure or a protective order or otherwise ensuring the confidential treatment of the Confidential Information; (iii) is disclosed with the prior written approval of an authorized officer of the Disclosing Party; (iv) is previously known to the Recipient at the time of disclosure; (v) is discovered by the Recipient without reference to the Confidential Information of the Disclosing Party; or (vi) is lawfully obtained from a third party which was not bound by a confidentiality agreement respecting the disclosure.

13.2 THC shall comply at all time with the data management and data access protocols implemented by the Affiliate to protect access to Confidential Information.

IN WITNESS WHEREOF, the Parties have executed this agreement effective as of the date first above written as attested by the hands of their respective officers duly authorized in that behalf:

TORONTO HYDRO TELECOM INC.

Per: _____
David Dobbin
President

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Per: _____
Anthony Haines
President

SCHEDULES FOR SERVICE LEVEL AGREEMENT BETWEEN

Toronto Hydro Telecom Inc.
and
Toronto Hydro-Electric System Limited

Schedule	Service Area	Page
Schedule 1	Internet	2

SCHEDULE 1

SERVICE AREA: **Internet**

ITEM	SECTION	COST
1	T1/T3 Connection to Internet	[redacted]

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Report to

Toronto Hydro-Electric System Limited

Regarding

Review of Shared Services Cost Allocation Methodology

June 30, 2007

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I. SUMMARY

The Enterprise Management Solutions Division of Black & Veatch Corporation ("BV" or "we") is pleased to submit this Report on our Review of Shared Services Cost Allocation Methodology ("Review") to Toronto Hydro-Electric System Limited ("THESL").

A. Background

THESL is an electric distribution utility regulated by the Ontario Energy Board ("OEB"). THESL is 100% owned by Toronto Hydro Corporation ("THC"). In its Decision with Reasons in OEB EB-2005-0421 ("OEB Decision"), the OEB directed THESL to improve its methodology for allocating the cost of shared services, including requiring specific changes to be made.

THESL revised its methodology to allocate shared services costs and prepared its *Report on Affiliate Transactions Regulatory Compliance: Methodology and Implementation* (dated June 2007) ("THESL Report") to document its response to the OEB Decision.

BV was engaged by THESL to perform this Review to determine whether the methodology for allocating the cost of shared services ("THESL Methodology"), as described in the THESL Report and as implemented, complies with the OEB Decision and with the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters ("ARC"). As part of our Review we:

- Read the relevant parts of the OEB Decision and the ARC
- Read, reviewed and analyzed the THESL Documentation (defined in Section II.I. THESL Documentation), as follows:
    - Read the reports identified in Section II.I.
    - Reviewed and analyzed the THESL Cost Allocation Model, the THC Cost Allocation and supporting calculations and documentation, identified in Section II.I.
    - Reviewed and analyzed the additional computations identified in Section II.I.
- Held discussions with THESL management personnel
- Compared the THESL Methodology to the relevant requirements of the OEB Decision and the ARC, as well as to current industry practices

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- Provided comments and suggestions about the THESL Methodology, the THESL and THC shared services cost allocation models and the THESL Report

B. Corporate Organization and Shared Services

THC is wholly owned by the City of Toronto ("City") and is the 100% owner of the following subsidiary companies:

- THESL, the regulated local electric distribution company serving Toronto, which has 95% of the group's consolidated revenues and assets,

- Toronto Hydro Energy Services Inc ("TH Energy"), an unregulated company providing street lighting and expressway lighting services and development of energy efficiency products and services, and

- Toronto Hydro Telecom Inc. ("Telecom"), an unregulated company providing fibre optic capacity and managing data communications services.

Executive and corporate services for the group are centralized in THC, which provides these services to each subsidiary. In addition, certain transactional and support activities are centralized in THESL and provided by THESL to THC, TH Energy and Telecom. THC charges the subsidiaries for the services that it provides, and THESL charges THC, TH Energy and Telecom for the services that it provides. The charges for these services are computed using the THESL Methodology.

C. Requirements of the OEB

The OEB requirements as applicable to THESL's shared services cost allocation methodology derive from the OEB Decision and the ARC.

The *OEB Decision* requires that THESL develop "a time-based shared services allocation methodology for non-direct corporate costs that incorporates the following elements;

1. time/cost tracking of individual efforts,
2. description of THESL's need for the service,
3. assessment protocol and allocation of non-time related expenses",

and to provide "a detailed report on the shared service allocation rationale and methodology (as) part of THESL's next rate application."

The relevant portions of *the ARC* provide as follows:

> 2.2.1 Where a utility shares services or resources with an affiliate it shall do so in accordance with a Services Agreement…(which) shall include (a) the type,

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quantity and quality of service; (b) pricing mechanisms; (c) cost allocation mechanisms.

2.3.1 Where a utility provides a service, resource or product to an affiliate, the utility shall ensure that the sale price is no less than the fair market value ("FMV") of the service, resource or product.

2.3.2 In purchasing a service, resource or product, from an affiliate, a utility shall pay no more than the FMV. For the purpose of purchasing a service, resource or product a valid tendering process shall be evidence of FMV.

2.3.3 Where FMV is not available…a utility shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital.

D. About BV; Scope of Assignment

The Enterprise Management Solutions Division of Black & Veatch Corporation provides strategic, economic and management consulting firm specializing in energy matters. We provide assistance in areas such as economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support and technical analysis. BV has assisted many dozens of electric, gas, water and telecommunications clients in hundreds of proceedings, including recent work in the area of shared services cost allocations.

Consistent with standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by THESL and we accepted factual statements made to us by THESL, subject only to overall reasonableness and actual contrary knowledge, but without independent confirmation.

All amounts in this Report are in Canadian dollars.

E. Summary of Findings, Conclusion and Recommendations

Findings

1. THESL has committed significant resources, as well as the support of THC and THESL management, to ensuring compliance with the OEB requirements for allocating the cost of shared services.

2. THESL's approach to development of the THESL Methodology meets the OEB requirements.

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3. The THESL Shared Services Inventory identifies all shared services and inter-affiliate transactions.

4. The THESL Methodology includes a review of transactions for compliance with the OEB's three-prong test. The shared services and inter-affiliate transactions meet the test.

5. The development of costs follows the OEB requirements as well as current industry practice, including:

    a. Direct assignment of costs where possible.
    b. Where direct assignment is not possible, allocation of costs based on time/cost tracking of individual efforts when possible.
    c. Where necessary, selection of appropriate "allocator proxies" based on cost causation or benefits received.

    Costs are appropriately computed on a fully-burdened basis and include direct costs (payroll and payroll-related costs), indirect costs (facilities, IT and fleet costs) and capital costs (depreciation and return on assets).

6. The time studies conducted by THC and THESL are appropriate for allocating the payroll and related costs of the shared services to which they were applied.

7. The services for which Unit of Usage Charges are used, and the basis for charging for those services, are appropriate. The Unit of Usage Charges are reasonably reflective of costs.

8. The process that THESL has established to estimate FMV for shared services and inter-affiliate transactions is well-thought out and considers relevant information. The potential sources of information that are identified appear to be likely to provide useful information. Where it was determined that the FMV is not reasonably available, the judgments appear reasonable and consistent.

    THESL Management has informed us that transfer prices for services provided by THESL will be charged out at the greater of the cost developed for each service or its FMV if applicable, and that transfer prices for services received by THESL will be charged to THESL at the lesser of the cost developed for each service cost or its FMV if applicable.

9. The THESL Documentation (defined in Section II.I. THESL Documentation), adequately documents:

    a. The THESL Methodology for allocating the cost of shared services

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b. The calculations of fully burdened costs as well as the amounts charged from THESL to THC, TH Energy and Telecom and from THC to THESL

c. The information used and judgments reached in the three-prong test (except as discussed in Section II.D. 3 Cost / Benefit); development of costs, including direct assignments, time/cost tracking and "allocator proxies" and determination of whether the estimated FMV for each transaction is reasonably available.

Conclusion

Based on our Review, the THESL Methodology for allocating the cost of shared services, as described in the THESL Report and as implemented, complies with the OEB Decision and with the OEB's Affiliate Relationships Code for Electricity Distributors and Transmitters ("ARC") and with current industry practice.

Recommendations

1. The THESL Report should include an explanation of how the cost / benefit review of the OEB's three-prong test was conducted, and should document the information relied on and judgments reached in performing the analysis. (Section II.D. 3 Cost / Benefit)

   Management Response (provided by THESL Management)

   Management believes that a sufficient review was performed on the cost / benefit portion of the OEB's three-prong test and no further documentation is required. Each transaction was approved and reviewed business unit managers and senior executives. In addition, members of the Steering Committee and Project Team spent considerable time discussing each transaction's merit and applicability.

2. The computation of Usage Charges should more closely reflect the THESL Methodology, including Occupancy, IT and Fleet charges, and charges for indirect labor only where explicitly indicated. (Section II.G. Unit of Usage Charges)

   Management Response (provided by THESL Management)

   Management will take the recommendation under advisement and conduct a research to determine whether including occupancy, IT and fleet charges is reasonable considering that such charges are already included in other areas. Management does not believe that such charges would have a material impact on the current allocation methodology.

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II. THESL APPROACH AND METHODOLOGY

This Section discusses THESL's overall approach to developing the THESL Methodology, as well as the THESL Methodology itself. Each subsection includes BV's Finding as to the item discussed.

A. THESL Resources and Management Support

As described in Section 2.5 of the THESL Report, THESL implemented a corporate-wide approach to ensuring compliance with the OEB requirements for allocating the cost of shared services, including:

- Developed corporate-wide strategy with the primary goal of ensuring compliance with the OEB Decision.
- Assigned significant departmental level resources to guide the corporate response.
- Created a Steering Committee comprised of senior THC and THESL staff.
- Appointed a Project Team within Corporate Finance under the sponsorship of the CFO. The Project Team included staff from THC and THESL, and a subject matter expert in an advisory capacity.

The information used and judgments developed were reviewed by THC and THESL management, including the CFO of THC and the presidents of the subsidiaries.

THESL also committed to continuing oversight activities such as periodic reviews, updating of data and management approval to ensure continued compliance with the OEB requirements. These activities are described in Section 2.5 of the THESL Report.

Finding 1. THESL has committed significant resources, as well as the support of THC and THESL management, to ensuring compliance with the OEB requirements for allocating the cost of shared services.

B. Approach to Development of THESL Methodology

As described in Section 2.6 of the THESL Report, THESL established the following procedure to develop the THESL Methodology to allocate the cost of shared services:

- Created an inventory of affiliate company service transactions,
- Determined how to cost each service,

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- Established criteria for identifying fair market value for each service, and
- Prepare a method to fairly allocate the cost of services to affiliates.

THESL's approach encompasses all of the important considerations of the OEB requirements, including identification of transactions, compliance with the OEB Decision and compliance with the ARC.

Finding 2. THESL's approach to development of the THESL Methodology meets the OEB requirements.

C. Identification of Shared Services and Inter-Affiliate Transactions

1. Shared Services and Inter-Affiliate Transactions Defined

THESL has defined shared services and inter-affiliate transactions to include:

- Services provided by or to THESL (the regulated utility) by THC or a subsidiary of THC, and
- Services provided to or by the City of Toronto (a THESL affiliate under ARC).

2. Shared Services and Inter-Affiliate Transactions Identified

To identify the activities that represent shared services and inter-affiliate transactions, as defined, THESL performed the following steps:

- Surveyed existing service level agreements.
- Reviewed financial system records.
- Held discussions with business managers and executives for THC, THESL, TH Energy and Telecom.
- Required THESL and THC personnel to complete timesheets, identifying the time spent providing services to each company in the group (including their own).

The shared services and inter-affiliate transactions identified by THESL in this process are listed in the Shared Services Inventory ("Inventory"), which is part of the THESL Report.

3. Review of Shared Services and Inter-Affiliate Transactions Inventory

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To ensure the completeness of the Inventory, BV reviewed the process employed by THESL, as described above. The process appears to be adequately designed with sufficient checks to identify the shared services and inter-affiliate transactions that had been known to THESL.

However, as described herein, due to a recent reorganization, BV designed its scope to include a review of services provided by THESL to other companies.

At the time of the OEB Decision, most of the shared services were provided by THC to THESL, TH Energy and Telecom; that is, all of the costs were incurred by THC, then charged by THC to THESL and the other companies. The OEB Decision primarily addresses costs that are incurred by THC and charged to THESL.

In a recent reorganization, many of the transactional and support shared services were moved from THC into THESL. As a result, to ensure the completeness of the Inventory, it was necessary to review both of the following potential sources of transactions:

- Services provided by THC and *charged to THESL*. Prior to the reorganization, this comprised most of the shared services. For these costs, the OEB requirement is to justify the costs that are being *charged to THESL*.

- Services performed by THESL and *charged by THESL* to the other companies. For these costs, the OEB requirement is to identify services performed by THESL for other companies in order to ensure that an appropriate amount is being *charged by THESL*.

To supplement the steps performed by THESL, BV discussed with THESL representatives the responsibilities of each THESL group, in order to ascertain whether such THESL group does in fact provide services to other THC or other companies. BV also considered whether THC and the other companies had the resources to perform such services for themselves. For example, BV verified that THESL does not perform Human Resource functions for TH Energy or Telecom because they share an employee (who is not a THESL cost).

Table 1 – Review of THESL Groups for Potential Shared Services Provided to Other Companies, below, shows for each THESL group whether it provides services to the other companies (THC, TH Energy or Telecom) and if so, the basis for charging costs from THESL to the other companies.

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Table 1 – Review of THESL Groups for Potential Shared Services Provided to Other Companies	
THESL Group (Department)	**Provides Services to Other Companies**
Customer Service	**No**: THC doesn't need; TH Energy and Telecom have own Customer Service groups
Accounting (Financial Planning)	**No**: Other companies have their own Financial Planning functions
Accounting (LDC)	**No**: Services relate to THESL 100%
Accounting (Accts. Payable, Payroll)	**Yes:** Services are provided to other companies
CDM	**No**: Services relate to THESL 100%
Communications	**Yes:** Services are provided to other companies
Environment, Health & Safety	**Yes:** Services are provided to other companies
Information Technology	**Yes:** Services are provided to other companies
Legal Services (Commercial, Litigation, Real property, Claims)	**Yes:** Services are provided to other companies
Human Resources	**Yes:** Services are provided to THC **No:** TH Energy, Telecom share HR person
Treasury	**Yes:** Services are provided to other companies
Rates and Regulatory	**No:** Services relate to THESL 100%
Asset Management (Facilities)	**Yes:** Services are provided to other companies
Asset Management (Fleet)	**Yes:** Services are provided to other companies
Asset Management (Acquisition Services)	**Yes:** Services are provided to other companies

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Table 1 – Review of THESL Groups for Potential Shared Services Provided to Other Companies	
THESL Group (Department)	**Provides Services to Other Companies**
Asset Management (Other departments)	**No**: Services relate to THESL 100%
Business Transformation	**No**: Services relate to THESL 100%
Chief Operating Officer	**No**: Services relate to THESL 100%
Distribution Grid	**No**: Services relate to THESL 100%
Distribution Services	**No**: Services relate to THESL 100%
Services charged on Unit of Usage Basis	**Yes:** Services are provided to other companies See Section II.G. Unit of Usage Charges

Finding 3. Based on the steps performed by THESL and the additional review performed by BV, THESL has identified all shared services and inter-affiliate transactions.

D. OEB Three-Prong Test

The THESL Methodology includes a review for compliance with the OEB's three-prong test. Originally (OEB Decision with Reasons in EBRO 493/494) the test applied to charges from a corporate entity to its utility subsidiaries; for THESL that would represent *costs charged by THC to THESL*. The THESL Methodology expands the test to apply to *costs charged by THESL* to the other companies.

1. Cost incurrence

Cost Incurrence addresses the questions: Are the services for which costs are being charged actually provided to the recipient? Are they needed by the recipient?

The THESL Methodology includes the following checks to ensure that this is the case, for both *costs charged to THESL* and *costs charged by THESL*.

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- Initial assessment by the Project Team to ensure that services for which costs are charged are applicable to THESL (Section 3.1.5 of THESL Report).

- Cross-check of information provided by service providers and service recipients in development of Shared Services Inventory (Section 3.1.4 of THESL Report).

- Review and sign-off as to accuracy and completeness by senior management of the provider and recipient companies (Section 3.1.5 of the THESL Report).

BV: (a) reviewed the process employed by THESL to ensure the appropriateness of Cost Incurrence, (b) reviewed and discussed the services for which THESL is being charged by THC, and (c) reviewed the Inventory to ensure that services provided by THESL to other companies are included. These steps provide reasonable assurance that the costs charged to THESL meet the Cost Incurrence test and that THESL is charging other companies for services it provides to them.

2. Cost Allocation

Cost Allocation addresses the question: Were the costs for the service appropriately allocated to the recipients?

The THESL Methodology applies a lower of cost or FMV (if FMV is applicable) to *costs charged to THESL*, and a greater of cost or FMV (if FMV is applicable) to *costs charged by THESL*. Costs reflect direct assignment, time reporting and appropriate allocator proxies. This Report concludes that these cost allocation methods are appropriate.

Subject to appropriate development of FMVs and appropriate application of the FMV's in determining transfer prices (see Section II.H. Development of Fair Market Values), both of which THESL management informs us will be completed in the future, the THESL Methodology meets the Cost Allocation test.

3. Cost / Benefit

Cost / Benefit addresses the question: Did the benefit received equal or exceed the cost?

In developing the Shared Service Inventory, each transaction was reviewed for compliance with the cost / benefit test of the OEB's three-prong test. However the THESL Report does not provide an explanation of how the cost / benefit review was conducted, and there does not appear to be documentation for the information relied on or judgments reached in performing the analysis.

Finding 4. The THESL Methodology includes a review of transactions for compliance with the OEB's three-prong test. However the THESL Report does not provide an explanation of how the cost / benefit review

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was conducted, and there does not appear to be documentation for the information relied on or judgments reached in performing the analysis.

Recommendation 1: The THESL Report should include an explanation of how the cost / benefit review of the OEB's three-prong test was conducted, and should document the information relied on and judgments reached in performing the analysis.

E. Development of Costs

The THESL Methodology utilizes two models to develop and allocate costs. In addition, charges for some services are based on Unit of Usage Charges which are discussed in Section II.G. Unit of Usage Charges.

The THESL Model develops and allocates costs incurred by THESL and the THC Model develops and allocates costs incurred by THC. Both models develop costs using direct assignment, time reporting and appropriate allocator proxies.

The models are described and discussed in Section III, THESL and THC Shared Services Cost Allocation Models.

Finding 5. As discussed in Section III.A. THESL Shared Services Cost Allocation Model, the development of costs follows the OEB requirements as well as current industry practice, including:

a. Direct assignment of costs where possible.

b. Where direct assignment is not possible, allocation of costs based on time/cost tracking of individual efforts when possible.

c. Where necessary, selection of appropriate "allocator proxies" based on cost causation or benefits received.

This reflects the following supporting findings:

THESL Model

- ✓ The nature of the items included in the THESL costs (including additions and adjustments) to be assigned and allocated among the THESL departments and THC, TH Energy and Telecom is appropriate (Section III.A. 2).
- ✓ The re-allocations of the costs for the Facilities, Information Technology and Fleet Departments among THESL departments and

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the other companies are based on appropriate usage factors including square footage, numbers of users and numbers of vehicles (Section III.A. 3).

- ✓ As noted in Finding 3, all shared services and inter-affiliate transactions in which THESL departments are providing services to other companies have been identified.

- ✓ The THESL departmental costs charged to other companies appropriately include direct costs (payroll and payroll-related costs), indirect costs (facilities, IT and fleet costs) and capital costs (depreciation and return on assets).

- ✓ The bases for charging THESL costs to other companies, including time studies and allocator proxies, as identified in Section III.A. 4, are reasonable. The test applied by BV is that the allocator proxy should have a *causal relationship* to the costs incurred in performing the activity; and if there is no reasonably available allocator proxy with a causal relationship, then selecting an allocator proxy based on *benefits received* is a fair and consistent treatment.

<u>THC Model</u>

- ✓ The nature of the items included in the THC costs to be assigned and allocated among the THC departments and THESL, TH Energy and Telecom is appropriate (Section III.B. 2).

- ✓ The distribution of THC costs among the departments is reasonable based on the nature of the costs (Section III.B. 3).

- ✓ The THC departmental costs charged to other companies appropriately include direct costs (payroll and payroll-related costs), indirect costs (facilities, IT and fleet costs) and capital costs (depreciation and return on assets).

- ✓ The basis for assigning and allocating THC costs among THC, THESL, TH Energy and Telecom, which include time studies, direct assignment and allocator proxies, are reasonable.

  The use of time studies for labor and labor-related costs is specifically required by the OEB Decision and consistent with current utility practice.

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The use of allocator proxies is reasonable. The test applied by BV is that the allocator proxy should have a *causal relationship* to the costs incurred in performing the activity; and if there is no reasonably available allocator proxy with a causal relationship, then selecting an allocator proxy based on *benefits received* is a fair and consistent treatment.

F. THC and THESL Time Studies

THC and THESL each conducted time studies in order to obtain the information necessary to allocate the costs of shared services, as required by the OEB decision and in accordance with current industry practice.

1. THC Time Study

THC provided each employee with a timesheet template and asked them to keep track of their hours on a daily basis over the 14-week period February 26, 2007 through June 3, 2007. Each employee reported the number of hours each day that were spent on each company- THC, THESL, TH Energy or Telecom, with a brief description of the work. Approximately 95% of employee timesheets were completed.

A properly performed time study measures cost causation and is widely accepted as a basis for allocating costs, and complies with the OEB Decision and current industry practice. BV reviewed the time study method used by THC and found it to be appropriate and a proper basis for allocating costs. Approximately $6,661,000 of THC costs (53% of total) were allocated based on the results of the THC time study.

2. THESL Time Study

Estimates of 2007 time for THESL employees were based on actual historical time records (adjusted for known upcoming changes) for some departments (representing 43% of costs allocated based on time), and on the judgments of managers and supervisors for areas for which they are directly responsible for other departments (representing 57% of costs allocated based on time). This is an appropriate basis of estimating 2007 time, especially considering the small number of employees in THESL whose costs were allocated based on time, and management's beliefs that such a study would require a significant level of effort and would not have a material impact on the results of the allocation methodology. Approximately $685,000 of THESL costs (13% of total allocated to other companies) were allocated based on the results of the THESL time study.

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Finding 6. The time studies conducted by THC and THESL are appropriate for allocating the payroll and related costs of the shared services to which they were applied.

G. Unit of Usage Charges

In addition to THESL costs that are allocated using the THESL Model, THESL provides some services to TH Energy and Telecom and charges for the services based on Unit of Usage Charges pursuant to Service Level Agreements ("SLAs"). Some of these services are provided on a time basis (i.e., charge per hour) and some on a job basis (i.e., charge per completed task). Examples of these services are:

- Overhead line relocations to accommodate installation of Telecom fibre attachments to THESL poles (Services provided to Telecom)
- Overhead & Underground street light equipment installation, removal, and/or transfer as part of emergency corrective maintenance requirements (Services provided to TH Energy)
- Overhead & Underground street light equipment installation, removal and/or transfer as part of planned projects. Civil street light infrastructure installations as part of planned projects (Services provided to TH Energy)
- Upon requests from the Street Lighting Division, the Locates Dept. will complete locate services related to third party locate requests (Services provided to TH Energy)

To review these charges, BV:

- Reviewed the Shared Services Inventory to identify those services for which THESL charges based on Unit of Usage Charges pursuant to Service Level Agreements
- Identified the Unit of Usage upon which charges are based for each such service
- Reviewed the computations of the Unit of Usage Charges for some of the services. The Usage Charges include direct labor costs, equipment costs and an estimate for indirect labor (supervisory, design, billing). While the amounts computed using this method are reasonably reflective of costs, it is recommended that the computation of Usage Charges more closely reflect the THESL Methodology, including

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Occupancy, IT and Fleet charges, and charges for indirect labor only where explicitly indicated.

Finding 7. The services for which Unit of Usage Charges are used, and the basis for charging for those services, are appropriate. The Unit of Usage Charges are reasonably reflective of costs.

Recommendation 2: The computation of Usage Charges should more closely reflect the THESL Methodology, including Occupancy, IT and Fleet charges, and charges for indirect labor only where explicitly indicated.

H. Development of Fair Market Values

THESL has established the following process with regard to Fair Market Value (FMV):

- Each shared services and inter-affiliate transaction is reviewed to determine if the FMV can be estimated from reasonably available information
- If so, the source of the information is identified, and the time required to obtain the FMV is estimated
- If not, the reason is identified, and in some cases an alternative such as benchmarking costs is considered.

The process is described in Section 3.3 of the THESL Report, with details provided in the document "*THC/THESL Business Analysis of the Findings of the Fair Market Value Expert Panel*".

The review process is comprehensive and the determination of whether FMV information is reasonably available considers:

- The time and cost that would be required to obtain the information, relative to the size of the transaction
- The complexity of the data (indicating the difficulty of making an apples-to-apples comparison)
- Whether the price is separately established by the OEB or other regulatory body (indicating FMV would not be used to set the price)
- Whether the service would ever be outsourced due to reasons of proprietary technology or business confidential information (indicating there is no third party that can provide comparable service)

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Finding 8. The process that THESL has established to estimate FMV for shared services and inter-affiliate transactions is well-thought out and considers relevant information. The potential sources of information that are identified are likely to provide useful information. Where it was determined that the FMV is not reasonably available, the judgments appear reasonable and consistent.

THESL Management has informed us that transfer prices for services provided by THESL will be charged out at the greater of the cost developed for each service or its FMV if applicable, and that transfer prices for services received by THESL will be charged to THESL at the lesser of the cost developed for each service cost or its FMV if applicable.

I. THESL Documentation

As part of our Review, we read the following reports:

- THESL Report
- Shared Services Inventory
- Report of the Expert Panel on Fair Market Value
- THC/THESL Business Analysis of the Findings of the Fair Market Value Expert Panel
- Shared Services: Fair Market Value Steering Committee Findings
- Corporate organization chart for THC and subsidiaries

As part of our Review, we reviewed and analyzed the following models and supporting calculations:

- THESL Shared Services Cost Allocation Model
- THESL Summary of Cost Allocation Model
- THC Shared Services Cost Allocation Model
- Facilities (Occupancy) charge calculation, including supporting documentation
- Information Technology (IT) charge calculation, including supporting documentation
- 2007 Operating Budgets for THESL, THC, TH Energy and Telecom

The reports, models and calculations identified above (taken as a whole the "THESL Documentation") provide:

- A clear and comprehensive overview of the THESL Methodology
- A description of the steps taken to develop the THESL Methodology
- Identification of the personnel involved and their roles

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- An auditable trail for all calculations (assuming the validity of the numbers)

- Support for the information used and judgments reached in:

  - The three-prong test (except as discussed in Section II.D. 3 Cost / Benefit)
  - Development of costs, including direct assignments, time/cost tracking and "allocator proxies"
  - Determination of whether the estimated FMV for each transaction is reasonably available

Finding 9. The THESL Documentation adequately documents:

a. The THESL Methodology for allocating the cost of shared services

b. The calculations of fully burdened costs as well as the amounts charged from THESL to THC, TH Energy and Telecom and from THC to THESL

c. The information used and judgments reached in the three-prong test (except as discussed in Section II.D. 3 Cost / Benefit); development of costs, including direct assignments, time/cost tracking and "allocator proxies" and determination of whether the estimated FMV for each transaction is reasonably available

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III. THESL AND THC SHARED SERVICES COST ALLOCATION MODELS

The THESL Methodology utilizes two models to develop and allocate costs. The *THESL Model* develops and allocates costs incurred by THESL and the *THC Model* develops and allocates costs incurred by THC.

This Section will describe and discuss the models.

A. THESL Shared Services Cost Allocation Model

This section provides an overview of the THESL Model, then describes each of the steps that the THESL Model uses to allocate costs.

1. Overview

The THESL Model starts with the THESL 2007 Operating Expense budget by department of $192.9 million.

Then, several additions and adjustments are made resulting in $182.7 million total costs.

Next, costs are re-allocated *from* the Facilities, Information Technology and Fleet departments, *among* all THESL departments and other companies.

Finally, each THESL department is reviewed to determine if it provides services to other companies (THC, TH Energy, Telecom) in addition to THESL. For those departments that provide services to other companies, costs are assigned or allocated based on direct assignment, time studies or allocator proxies.

2. Total THESL Costs Including Additions and Adjustments

The components of THESL total costs, including additions and adjustments to the THESL 2007 Operating Expense departmental budget, are shown in Table 2.

Table 2 – Development of THESL 2007 Total Costs

Item	Amount ($ 000s)
Operating Expense Budget (Includes payroll, indirect costs and expenses)	$192,933
Property taxes	7,348
Payments in lieu of Capital taxes and Income taxes	7,008
Warehouse costs charged to Overhead	(7,972)

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Table 2 – Development of THESL 2007 Total Costs	
Item	**Amount ($ 000s)**
Recoveries (CDM revenue)	(19,146)
Regulatory assets (Smart Meters, HR, EDR, System Reliability)	(4,470)
Charge from THC	6,977
Total THESL Costs	**182,678**
Cost Recoveries and Allocations:	
Unit of Usage - Radio	(496)
Unit of Usage - Procurement	(316)
Unit of Usage - Cable locates, Other Street lighting	(390)
Subtotal- Unit of Usage	(1,202)
Subtotal	181,476
Facilities (Occupancy)	(612)
Information Technology	(966)
Fleet	(755)
Stewardship	(2,646)
Subtotal- Assignments and Allocations	(4,979)
Net THESL Costs	**$176,497**

3. Re-Allocations for Facilities, Information Technology and Fleet Departments

The Operating Expense budget costs for the Facilities, Information Technology and Fleet departments are re-allocated *out of the respective departments* and *into all THESL departments and other companies*. Unit costs are developed for the Facilities, Information Technology and Fleet departments. The unit costs are based on usage: square feet for Facilities; users for IT; and vehicles for Fleet. Then, the respective unit costs for Facilities, Information Technology and Fleet are re-allocated among all THESL departments and other companies on the basis of their square feet utilized, numbers of users, and numbers of vehicles.

A similar treatment is applied to Lab Service department costs and Tool Crib department costs, except that these costs are not charged to any other companies because they relate 100% to THESL operations.

The Facilities, Information Technology and Fleet charges are discussed below.

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(a) Facilities (Occupancy) Charge

The Facilities (Occupancy) charge includes the following items:

Table 3 – Items Included in Facilities (Occupancy) Charge	
Item	**Amount ($ 000s)**
Labor and Vehicles	$4,845
Direct and material costs	5,197
Utilities, Supplies, Employee costs, Rentals	5,421
Property and Municipal tax	7,348
Return on assets	8,791
Depreciation	3,586
IT charge	211
Other	1,025
Total	**$36,424**

The total Facilities cost is split among the different types of facilities- Office, Station, Warehouse and Outdoor- based on an analysis of the labor and non-labor costs associated with each type of space.

Then, a rate per square foot is developed for each type of space. The square footage used in developing the rates is the total square feet for each THESL department as well as for THC, TH Energy and Telecom, including common areas.

Table 4 – Development of Facilities Charge by Type of Space			
Type of Space	**Portion**	**Sq Ft**	**$ / Sq Ft**
Office	52%	618,630	$30.62
Station	23%	805,363	$10.40
Warehouse	15%	269,400	$20.28
Outdoor	10%	4,398,703	$0.83
Total	**100%**		

The rate per square foot is applied is to the usage of space by each THESL department and by each of THC, TH Energy and Telecom. This is done as a two-step process- first for usable square footage and then for common areas.

The Facilities costs allocated to each THESL department and to THC are included in the amounts subsequently allocated out of each THESL department and THC.

(b) Information Technology Charge

The Information Technology ("IT") charge includes the following items:

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Table 5 – Items Included in Information Technology Charge	
Item	**Amount ($ 000s)**
Network, Telephony, Desktop, Laptop, Workstation and Tablet operating expense budget (a)	$6,571
Depreciation	395
Return on assets	133
IT Charge- Network, Telephony, Desktop, Laptop, Workstation, Tablet	7,099
Ellipse and Hyperion	3,246
Subtotal	10,345
Applications direct to THESL (CIS Banner, Outage Management, Distribution Management, GEAR, other engineering applications)	8,262
Programs and projects direct to THESL	2,266
Total IT Budget	**$20,873**
(a) Includes Labor and Vehicles; Direct and material costs; Utilities, Supplies, Employee costs, Rentals	

The costs for Network, Telephony, Desktop, Laptop, Workstation and Tablet are split based on capital budget costs for 2002-2006. Then, a rate per user is developed for each component. The number of users used in developing the rates is the total users for each THESL department as well as for THC, TH Energy and Telecom.

Table 6 – Development of IT Charge by Component			
IT Service	**Cost ($000s)**	**Users**	**$ / User**
Network	$2,630	1,738	$1,513
Telephony	1,376	2,301	$598
Desktop	1,841	1,058	$1,739
Laptop	854	385	$2,218
Workstation	388	210	$1,848
Tablet	10	4	$2,413
Subtotal	7,099		
Ellipse and Hyperion (a)	3,246	1,769	$1,835
Total	**$10,345**		
(a) Allocated based on FTEs not users.			

The rate per user for each type of IT service is applied to the numbers of users in each THESL department and in each of THC, TH Energy and Telecom.

The IT costs allocated to each THESL department and to THC are included in the amounts allocated out of each department and THC.

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(c) Fleet Charge

The Fleet charge reflects $13.8 million in costs. The total is divided between Trucks- 60% and Automobiles- 40%. Unit rates are developed for Trucks and Automobiles and the costs are allocated among the THESL departments and each of THC, TH Energy and Telecom, based on their numbers of Trucks and Automobiles.

4. Allocations of THESL Departmental Costs to Other Companies

After the Facilities, IT and Fleet costs are re-allocated into each THESL department, each department is reviewed to determine if it provides services to other companies (THC, TH Energy, Telecom) in addition to THESL. The results of this review are summarized in Table 1 – Review of THESL Groups for Potential Shared Services Provided to Other Companies above.

For those THESL departments that do provide services to other companies, costs are assigned or allocated based on direct assignment, time studies or allocator proxies. The basis for charging out the costs of each department is also listed in Table 7 below.

Table 7 – Basis for Charges for Services THESL Provides to Other Companies

THESL Group (Department)	Services Provided to Other Companies	Basis for Charges
Accounting (Accts. Payable)	• Process and pay supplier invoices, check requisitions, customer refunds, employee expense reimbursements • Maintain Ellipse modules and business processes related to AP • Manage accruals (THESL and THC) • Audit/review and summary of expense claims, executive expenditures • Maintain internal controls on physical supplies and periodic review of risks • Monthly AP reconciliations (THESL and THC) • Interface and assist Tax and Treasury with AP related matters • General client support	# invoices

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Table 7 – Basis for Charges for Services THESL Provides to Other Companies		
THESL Group (Department)	**Services Provided to Other Companies**	**Basis for Charges**
Accounting (Payroll)	• Process payroll; Prepare T4's, T4A's • Prepare and submit related remittances to government, other agencies • Maintain related Ellipse modules, ADP applications and business processes • Maintain internal controls and periodic review of risks • Monthly payroll account reconciliations • Interface and assist HR payroll related matters and general client support	# FTEs
Communications (Public Affairs)	• Assist in execution of public and stakeholder relations programs to the public, media, shareholder and stakeholders • Provide brand oversight	Time estimate
Communications (Community Involvement)	• Strategic planning, development and execution of community involvement, corporate sponsorship and corporate responsibility	# employees
Environment, Health & Safety	• Provide recommendations and advice on EHS issues • Conduct and co-ordinate health & safety educations and trainings, maintain health and safety records • Accident/incident investigations	# union employees
Information Technology	See section III.A. 3(b), Information Technology Charge	IT Charge

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Table 7 – Basis for Charges for Services THESL Provides to Other Companies		
THESL Group (Department)	**Services Provided to Other Companies**	**Basis for Charges**
Legal Services	• Commercial- Legal advice on commercial contracts; general corporate policies, procedures • Litigation- Initiation and defense of legal proceedings for and against TH & Affiliates • Real Property- Initiation, drafting and review of legal documents (Offer to Connect, Supply Agreement, Alternative Bid Proposal, Easement) related to real property development and supply arrangements thereto; Advice on and preparation of legal documents for execution for TH real property transactions; Investigate and respond to easement inquiry letters from purchasers of property • Claims- Revenue recovery processes	Time

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Table 7 – Basis for Charges for Services THESL Provides to Other Companies		
THESL Group (Department)	**Services Provided to Other Companies**	**Basis for Charges**
Human Resources	• Support for organizational staff planning • Design and administer active and retiree benefits programs and compensation • Salary administration • Job evaluation • Manage Human Resources Information System and reporting requirements • Support design and implementation of HR strategic initiatives • Design, assess and audit internal HR policies, programs and processes • Provide data to financial/regulatory reporting and rate filing • Supports: Labour & employee relations; recruitment, selection & on-boarding; Job analysis & design; Employee performance and attendance management; Legislative compliance; supporting corporate initiatives; providing data to financial/regulatory reporting and rate filing; and the development of HR policies and procedures	# employees
Treasury	• Cash management • Credit management • Debt management • Financing Strategy • Insurance management • Investor Relations • Monthly accounting/reporting:	Time
Asset Management (Facilities)	See section III.A. 3(a), Facilities (Occupancy) Charge	Facilities Charge
Asset Management (Fleet)	See section III.A. 3(c), Fleet Charge	Fleet Charge
Asset Management (Acquisition Services)	• Process purchase orders, RFPs, bulk purchasing	# POs

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For those THESL departments that do provide services to other companies, Table 8 – Summary of Direct Assignment, Time Study or Allocator Proxies for Costs Allocated from THESL, summarizes the amounts assigned or allocated based on direct assignment, time studies or allocator proxies.

Table 8 – Summary of Direct Assignment, Time Study or Allocator Proxies for Costs Allocated from THESL to Other Companies ($ 000s)

Department	Total	Direct Assign-ment	Time Studies (a)	Alloc-ator Proxies
Accounting	$327	$0	$0	$327
Communications	208	128	80	
Environment, Health & Safety	45			45
Information Technology	1,313			1,313
Legal Services	668	378	290	
Human Resources	99	2	97	
Treasury	733	515	218	
Asset Management (b)	1,586	612		974
	$4,979	**$1,635**	**$ 685**	**$2,659**

(a) Includes Support costs and Facilities (Occupancy), IT and Fleet costs charged to the respective THESL departments
(b) Includes Facilities (Occupancy), Fleet and Acquisition Services costs charged to other companies

Table 9 – Summary of THESL Costs Allocated Among All Companies summarizes the mounts assigned or allocated *from* THESL, *to* each company, by group, based on the bases for charging listed in Table 7 and the direct assignments, time studies and allocator proxies listed in Table 8.

Table 9 – Summary of THESL Costs Allocated Among All Companies ($ 000s)

Department	Total	THESL	THC	TH Energy	Telecom
Customer Services	$42,959	$42,959	$0	$0	$0
Finance and Accounting	3,708	3,381	82	109	136
CDM	3,570	3,570			
Communications	3,815	3,607	175	17	16
EH&S	2,619	2,574		4	41
IT	22,186	20,873	351	411	551
Legal	3,314	2,646	522	76	70
Human Resources	4,276	4,177	99		

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Table 9 – Summary of THESL Costs Allocated Among All Companies ($ 000s)					
Department	**Total**	**THESL**	**THC**	**TH Energy**	**Telecom**
Stewardship & Governance	12,763	12,763			
Treasury	11,112	10,378	408	203	123
Asset Management (a)	12,881	11,296	603	716	266
Business Transformation	6,103	6,103			
COO	546	546			
Distribution Grid	36,116	36,116			
Distribution Services	15,508	15,508			
Total	**$181,476**	**$176,497**	**$2,240**	**$1,536**	**$1,203**
(a) Includes Facilities, IT, and Fleet charges, and Acquisition Services					

B. THC Shared Services Cost Allocation Model

This section provides an overview of the THC Model, then describes each of the steps that the THC Model uses to allocate costs.

1. Overview

The THC Model starts with the THC 2007 Operating Expense budget by department of $10.2 million.

Then, the charges from THESL for Facilities, IT, Fleet, as well as the departmental allocations based on time studies and allocator proxies, are added to the THC Operating Expense budget, resulting in $12.4 million total costs for THC to allocate. The charges from THESL are spread among THC's department's as discussed in subsection III.B. 2 below.

Next, the fully-burdened labor cost for each THC department is allocated among THC, THESL, TH Energy and Telecom based on time studies. The charges from THESL for items that are causally related to labor, including Facilities, IT, Fleet and certain other costs, are allocated proportionately to labor costs.

Then, where possible, non-labor costs for each THC department are directly assigned to THC, THESL, TH Energy and Telecom.

Finally, the remaining costs in each THC department, which include non-labor costs in the Operating Expense budget and amounts charged from THESL, are allocated among THC, THESL, TH Energy and Telecom in the same proportion as the fully-burdened labor costs, except in two cases case where other allocator proxies are used.

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2. Development of Total THC Costs

THC total costs are shown in Table 10, indicating the $10.2 million incurred by THC (i.e., THC Operating Expense budget) as well as the costs that were allocated from THESL. Table 10 also shows if the amounts of costs allocated or assigned based on direct assignment, time studies or allocator proxies.

Table 10 – Development of THC 2007 Total Costs ($ 000s)

Item	Total	Time Study	Direct Assign-ment	Allocator Proxy (a)
THC 2007 Budget	$10,157	$5,351	$3,074	$1,732
From THESL:				
Facilities	486	486		
IT	269	269		
Fleet	78	78		
Treasury	408			408
Accounting	82	82		
Legal	522		210	312
Communications	176	176		
Human Resources	99	99		
Acquisition Services	39	39		
Ellipse / Hyperion	81	81		
Total	**$12,397**	**$6,661**	**$3,284**	**$2,452**

(a) Allocator for Treasury costs is Long Term Debt. Allocator proxy for $500,000 of costs related to corporate events and fundraising is headcount. Allocator proxy for each other cost is the appropriate departmental time study.

3. Development of Departmental THC Costs

The costs from THESL for Facilities, IT and Fleet were spread among the THC departments based on square footage, numbers of users and numbers of vehicles, respectively, which are the bases that were used to allocate the costs among the companies, as discussed in Section III.A. 3, Re-Allocations for Facilities, Information Technology and Fleet Departments.

The costs from THESL for Treasury were charged to the Finance- Corporate Control department.

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The costs from THESL for Accounting, Communications, Human Resources and Acquisition Services were allocated among the THC departments based on headcount, which is reasonable because these are support services.

4. Allocation of THC Costs Among the Companies

(a) Time Studies

THC conducted time studies for each department. In the time studies, each employee indicated the percent of time spent on each company- THC, THESL, TH Energy and Telecom. The THC Model allocates the fully-burdened labor costs for each department among the companies based on the results of the time studies. The total time-related costs were $6,661,000.

(b) Direct Assignment

THC identified the following items for direct assignment to specific companies ($000s):

• Consulting projects and studies (Note A)	$1,194
• Provincial capital tax (THC)	697
• Audit fees (all companies)	670
• Board of Directors per diem fees (all companies)	318
• Legal costs (THC)	210
• Property taxes (THC)	120
• Corporate memberships (THC)	75
Total	$3,284

Note A: Corporate consulting for THC- $750,000; Human Resources consulting primarily for THESL- $224,000; IT consulting for THESL- $220,000.

(c) Allocator Proxies

The remaining costs were charged from THC to the companies using allocator proxies, as follows:

Treasury costs from THESL, $408,000, were allocated based on utilization of the proceeds of the Long Term Debt, reflecting that the most relevant causal factor was that these costs relate to debt management, investor relations and financing strategy.

Costs for items such as corporate events, fundraising and teambuilding, $500,000, were allocated based on headcount, reflecting that these costs are related to the number of employees.

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Remaining costs, $1,544,000, were allocated in the same proportion as the labor time study results for each department. THC estimated that approximately half of these costs are employee-related expenses, such as training and general costs, and are therefore causally related to labor time. The balance of costs comprise numerous items, each too small to examine individually. For these items the use of the time study as a default allocator is reasonable considering that to examine the many small items would take considerable time.

Table 11 summarizes the total costs for each THC department, the amounts remaining with THC and the amounts assigned and allocated to THESL.

Table 11 – Summary of THC Costs Remaining in THC or Charged to THESL ($ 000s)

Department	Total	THC	THESL
Stewardship and Governance	$2,327	$1,188	$861
Legal	1,414	447	696
Financial	6,718	1,819	4,218
Communications and Marketing	744	551	170
EH&S and Human Resources	1,194	141	1,032
Total	**$12,397**	**$4,146**	**$6,977**

Table 12 summarizes the THC costs remaining with THC and the amounts assigned and allocated to THESL, based on the assignment or allocation method - time studies, direct assignment or allocator proxies.

Table 12 – Summary of THC Costs Allocated Among Companies By Direct Assignment, Time Study or Allocator Proxies ($ 000s)

Method	Total	THC	THESL
Time studies	$6,661	$1,684	$4,339
Direct assignment	3,284	1,979	929
Allocator proxies	2,452	483	1,709
Total	**$12,397**	**$4,146**	**$6,977**

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GLOSSARY

ARC means the Affiliate Relationships Code for Electricity Distributors and Transmitters of the OEB

BV means Black & Veatch Corporation

Fair Market Value means fair market value

Inventory means the services and inter-affiliate transactions identified by THESL and listed in the Shared Services Inventory

OEB means the Ontario Energy Board

OEB Decision means the Decision with Reasons in OEB EB-2005-0421

OEB three-prong test means the test described in Decision with Reasons, EBRO 493/494

SLA means Service Level Agreement, an agreement that specifies the nature and quality of service, price and terms and conditions for the provision of services

THC means Toronto Hydro Corporation, which owns 100% of THESL and is 100% owned by the City of Toronto

THESL Documentation means the reports, models and supporting calculations identified in Section II.I. THESL Documentation of the Report

THESL Methodology means THESL's methodology for allocating the cost of shared services as described in the THESL Report

THESL Report means the Report on Affiliate Transactions Regulatory Compliance: Methodology and Implementation prepared by THESL to document its response to the OEB Decision

THESL means Toronto Hydro-Electric System Limited, an electric distribution utility serving Toronto and regulated by the OEB, which is 100% owned by THC

TH Energy means Toronto Hydro Energy Services Inc, an unregulated company providing street lighting and expressway lighting services and development of energy efficiency products and services

Telecom means Toronto Hydro Telecom Inc., an unregulated company providing fibre optic capacity and managing data communications services

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SHARED SERVICES PROJECT

THESL PAID AND SOLD TO AFFILIATES - SUMMARY OF ASSUMPTIONS

Highlights

The "THESL Paid to THC" document (Appendix A) summarizes the costs to Toronto Hydro-Electric System Limited for services received from Toronto Hydro Corporation ("THC").

The "THESL Sold to Affiliates" document (Appendix B) summarizes all costs charged by THESL to THC, Toronto Hydro Energy Services Inc. ("TH Energy") and Toronto Hydro Telecom Inc. ("THTI") for services rendered by THESL.

The "THESL Paid to THC" and "THESL Sold to Affiliates" tables include details of all allocations by fiscal year and functional group and reflect the following information:

- 2006 costs are based on historical information.
- In 2006 THC initiated a number of changes to minimize the shared services inter-affiliate transactions to develop a high level of autonomy amongst affiliates, and to achieve greater regulatory clarity. The intent was to reduce the amount of shared service costs being transferred between THESL and non-regulated entities. As a result there was a reduction of $43.0M in services purchased by THESL from THC between 2006 and 2007. There was also a decrease of $1.1M in services purchased by THC from THESL between 2006 and 2007.
- As a result of the reorganization, the amounts that THESL sold to TH Energy and THTI increased between 2006 and 2007. Correspondingly, there was a decrease in the amounts that THC sold to TH Energy and THTI in the same time period.

Effective January 1, 2007, the following functional groups were reorganized and some groups and activities previously contained in THC were transferred to THESL.

Other groups and activities were split between THC and THESL. These changes are shown on Table 1 below.

Table 1: Reorganization

THC 2006	THC 2007	THESL 2007
Governance	→	
Finance:		
Accounts Payable & Payroll	→	→
Reporting & Planning	→	→
Tax	→	
Treasury	→	→
Rates & Regulatory Affairs	→	→
Organizational Effectiveness	→	→
Legal	→	→
Communications	→	→
Information Technology Services	→	→
Environmental, Health & Safety	→	→

Assumptions - THESL Paid to THC

- 2008 costs increase from 2007 based on expected increase in external costs (2.30%).
- 2009 costs increase from 2008 based on expected increase in external costs (2.40%).
- 2010 costs increase from 2009 based on expected increase in external costs (2.10%).

Assumptions - THESL Sold to Affiliates

- 2008 costs increase from 2007 based on expected increase in external costs (2.30%).
- 2008 Finance, OE, Legal, Communication and EH&S services no longer provided to THC and Finance services no longer provided to TH Energy and THTI.

- 2009 costs increase from 2008 based on expected increase in external costs (2.40%).
- 2010 costs increase from 2009 based on expected increase in external costs (2.10%).

Shared Services
Toronto Hydro-Electric System Limited
THESL Paid to THC

Amounts in Base Dollars

Functional Group	2006 Historical	2007 Bridge	2008 Test	2009 Test	2010 Test
	$	$	$	$	$
Governance	3,796,005	2,884,187	3,234,773	3,345,844	3,449,778
Finance	7,267,017	3,891,066	4,446,516	4,555,769	4,670,698
Treasury	3,876,258	-	-	-	-
Organization Effectiveness	3,484,303	593,593	636,543	696,671	681,539
Legal	2,959,255	367,785	575,021	597,364	620,896
Communications	4,060,240	123,301	134,873	140,864	147,377
ITS & Management	18,670,446	-	-	-	-
Environmental, Health, & Safety	2,587,462	414,213	447,924	464,591	483,434
Rates	862,835	-	-	-	-
Regulatory Affairs	3,682,188	-	-	-	-
GRAND TOTAL	**51,246,009**	**8,274,145**	**9,475,650**	**9,801,102**	**10,053,722**

Assumptions

1- 2006 Costs based on historical information
2- 2006 CDM Program not included ($170,689)
3- 2007-2010 Costs based on THESL EDR Application

Shared Services
Toronto Hydro-Electric System Limited
THESL Sold to Affiliates

Amounts in Base Dollars

2006 Historical			
Functional Group	**Sold to THC**	**Sold to TH Energy**	**Sold to Telecom**
	$	**$**	**$**
Asset Management	3,077,574	[redacted]	[redacted]
Finance	-	-	-
Treasury	-	-	-
Organization Effectiveness	-	-	-
Legal	-	-	-
Communications	-	-	-
ITS & Management	-	-	-
Environmental, Health, & Safety	-	-	-
GRAND TOTAL	**3,077,574**	[redacted]	[redacted]

Assumptions

1- 2006 Costs based on historical information
2- 2006 includes Fleet Charges and Occupancy Costs provided by THESL. 2006 IT Shared Services were provided by THC

Shared Services
Toronto Hydro-Electric System Limited
THESL Sold to Affiliates

Amounts in Base Dollars

2007 Bridge			
Functional Group	**Sold to THC**	**Sold to TH Energy**	**Sold to Telecom**
	$	**$**	**$**
Asset Management	1,179,151	[redacted]	[redacted]
Finance	-	-	-
Treasury	500,000	[redacted]	[redacted]
Organization Effectiveness	-	[redacted]	[redacted]
Legal	-	[redacted]	[redacted]
Communications	-	[redacted]	[redacted]
ITS & Management	269,947	[redacted]	[redacted]
Environmental, Health, & Safety	-	[redacted]	[redacted]
GRAND TOTAL	**1,949,098**	[redacted]	[redacted]

Assumptions

1- 2007 THC/THESI/THTI Costs based on EDR Application
2- 2007 Costs increase from 2006 due to THC and THESL Restructuring

Shared Services
Toronto Hydro-Electric System Limited
THESL Sold to Affiliates

Amounts in Base Dollars

2008 Test			
Functional Group	**Sold to THC**	**Sold to TH Energy**	**Sold to Telecom**
	$	**$**	**$**
Asset Management	1,255,596	[redacted]	[redacted]
Finance	-	-	-
Treasury	500,000	[redacted]	[redacted]
Organization Effectiveness	-	[redacted]	[redacted]
Legal	-	[redacted]	[redacted]
Communications	-	[redacted]	[redacted]
ITS & Management	276,156	[redacted]	[redacted]
Environmental, Health, & Safety	-	[redacted]	[redacted]
GRAND TOTAL	**2,031,752**	[redacted]	[redacted]

Assumptions

1- 2008 Costs based on 2008 Shared Services Model for EDR Purpose
2- 2008 Costs increase from 2007 based on expected general increase in costs (2.30%)
3- Finance Costs no longer provided to THESI (&THSLI) and THTI in 2008

Shared Services
Toronto Hydro-Electric System Limited
THESL Sold to Affiliates

Amounts in Base Dollars

2009 Test			
Functional Group	**Sold to THC**	**Sold to TH Energy**	**Sold to Telecom**
	$	**$**	**$**
Asset Management	1,287,844	[redacted]	[redacted]
Finance	-	-	-
Treasury	500,000	[redacted]	[redacted]
Organization Effectiveness	-	[redacted]	[redacted]
Legal	-	[redacted]	[redacted]
Communications	-	[redacted]	[redacted]
ITS & Management	282,784	[redacted]	[redacted]
Environmental, Health, & Safety	-	[redacted]	[redacted]
GRAND TOTAL	**2,070,628**	[redacted]	[redacted]

Assumptions

1- 2009 Costs based on 2009 Shared Services Model for EDR Purpose
2- 2009 Costs increase from 2008 based on expected general increase in costs (2.40%)

Shared Services
Toronto Hydro-Electric System Limited
THESL Sold to Affiliates

Amounts in Base Dollars

2010 Test			
Functional Group	**Sold to THC**	**Sold to TH Energy**	**Sold to Telecom**
	$	**$**	**$**
Asset Management	1,336,464	[redacted]	[redacted]
Finance	-	-	-
Treasury	500,000	[redacted]	[redacted]
Organization Effectiveness	-	[redacted]	[redacted]
Legal	-	[redacted]	[redacted]
Communications	-	[redacted]	[redacted]
ITS & Management	288,722	[redacted]	[redacted]
Environmental, Health, & Safety	-	[redacted]	[redacted]
GRAND TOTAL	**2,125,187**	[redacted]	[redacted]

Assumptions

1- 2010 Costs based on 2010 Shared Services Model for EDR Purpose
2- 2010 Costs increase from 2009 based on expected general increase in costs (2.10%)