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

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order or Orders approving and fixing just and reasonable rates effective May 1, 2006.

Application to the Ontario Energy Board by Toronto Hydro-Electric System Limited for 2006 Electricity Distribution Rates

RP-2005-0020 / EB-2005-0421

August 2, 2005

Rick Zebrowski, Vice-President
Regulatory Services
Toronto Hydro Corporation
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Toronto, ON M5B 1K5
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RP-2005-0020
EB-2005-0421

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, being 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, 2006.

Title of Proceeding:	An Application by **TORONTO HYDRO-ELECTRIC SYSTEM LIMITED** for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2006.
Applicant's Name:	**TORONTO HYDRO-ELECTRIC SYSTEM LIMITED** ("THESL")
Applicant's Address:	14 Carlton Street Toronto, Ontario M5B 1K5
Applicant's Counsel:	J. Mark Rodger Borden Ladner Gervais LLP Suite 4100 40 King Street West Toronto M5H 3Y4 Telephone: (416) 367-6190 Fax: (416) 361-7088 E-mail: mrodger@blgcanada.com

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, being 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, 2006.

APPLICATION

1. Introduction

(a) **TORONTO HYDRO-ELECTRIC SYSTEM LIMITED** ("THESL") hereby applies to the Ontario Energy Board (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, effective May 1, 2006.

(b) Except where specifically identified in the Application, THESL followed the methodology set out in the OEB's 2006 Electricity Distribution Rate Handbook, issued on May 11, 2005 (the "DRH"). THESL has chosen the "forward test year" filing option for its Application.

2. Proposed Distribution Rates and Other Charges

(a) The Schedule of Rates and other Charges proposed in this Application is identified in Exhibit A attached to this Form of Application.

(b) The material being filed in support of this Application sets out THESL’s approach to its 2006 distribution rates and charges.

3. Proposed Effective Date of Rate Order

(a) THESL requests that the OEB make its Rate Order effective May 1, 2006, in accordance with the DRH.

4. Proposed Distribution Rates and Other Charges are Just and Reasonable

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

(i) the proposed rates for the distribution of electricity have been prepared in accordance with the OEB's DRH;

(ii) 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;

(iii) this Application is authorized by Rick Zebrowski, Vice President Regulatory Services, Toronto Hydro Corporation; and

(iv) such further and other grounds as may be set out in the Summary accompanying this Form of Application.

5. Proposed Modification of Account 1508 or Establishment of Variance Account

(a) THESL requests that the OEB modify the scope of Account 1508 – Other Regulatory Assets – sub-account OEB Cost Assessments ("Account 1508") or establish a new variance account to allow the recording, for reconciliation at a later date, of the differences, if any, between the amounts recoverable in THESL's OEB-approved revenue requirement on account of Electrical Safety Authority fees and regulatory costs associated with regulatory proceedings, (including, without limitation, intervenor, consultant, and legal costs) and the actual costs incurred by THESL in this regard. These may include, without limitation, ratemaking proceedings; combined proceedings on matters relating to OEB Codes; or policy-oriented proceedings conducted by the Board.

(b) THESL further requests that estimates of the above-mentioned costs be factored into the derivation of rates effective May 1, 2006 and that the account track the variance of estimated-to-actual costs for reconciliation in future rate adjustments, as appropriate.

(c) THESL submits that the modification of the scope of Account 1508 or establishment of a new variance account is just and reasonable in light of:

(i) the significant costs that can arise out of participation in the OEB's proceedings and initiatives and the uncertainty from year to year as to the numbers of proceedings the Board will convene and their anticipated cost;

(ii) the desire to protect the ratepayer or the shareholder from benefiting at the expense of the other party with regard to the costs associated with these proceedings; and

(iii) the fact that the underlying circumstances associated with this risk are beyond THESL's ability to control.

6. Relief Sought

(a) THESL applies for an Order or Orders approving the adjusted 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* being Schedule B to the *Energy Competition Act*, *1998*, S.O. 1998, c.15, effective May 1, 2006.

(b) THESL requests that the OEB modify the scope of Account 1508 – Other Regulatory Assets – sub-account OEB Cost Assessments ("Account 1508") or establish a new variance account to allow the recording, for reconciliation at a later date, of the differences, if any, between the amounts recoverable in THESL's OEB-approved revenue requirement on account of Electrical Safety Authority fees and regulatory costs associated with regulatory proceedings, (including, without limitation, intervenor, consultant, and legal costs) and the actual costs incurred by THESL in this regard.

Dated at Toronto, Ontario this 2nd day of August, 2005.

All of which is respectfully submitted,

BORDEN LADNER GERVAIS LLP

J. Mark Rodger
Borden Ladner Gervais LLP
Suite 4100
Scotia Plaza
40 King Street West
Toronto M5H 3Y4
Telephone: (416) 367-6190
Fax: (416) 361-7088
E-mail: mrodger@blgcanada.com

Counsel to Toronto Hydro-Electric System Limited

Exhibit "A"

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
PROPOSED SCHEDULE OF RATES
EFFECTIVE MAY 1, 2006

RESIDENTIAL

Standard

Customer Charge	(per 30 days)	$12.62
Distribution Charge	(per kWh)	$0.0162
Transmission Charge	(per kWh)	$0.0102
Rate Rider	(per kWh)	$0.0032

GENERAL SERVICE

Monthly demand of less than 50 kW

Standard

Customer Charge	(per 30 days)	$16.91
Distribution Charge	(per kWh)	$0.0194
Transmission Charge	(per kWh)	$0.0103
Rate Rider	(per kWh)	$0.0015

Monthly demand 50 to 1,000 kW

Non Interval Meters

Customer Charge	(per 30 days)	$26.92
Distribution Charge	(per Max kVA/30 days)	$5.25
Transmission Charge	(per Max kW/30 days)	$3.91
Transformer Allowance	(per Max kVA/30 days)	$0.62
Rate Rider	(per kVA/30 days)	$0.31

Interval Meters

Customer Charge	(per 30 days)	$27.17
Distribution Charge	(per Max kVA/30 days)	$5.23
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.27
- Connection	(per Max kW/30days)	$1.71
Transformer Allowance	(per Max kVA/30 days)	$0.62
Rate Rider	(per Max kVA/30 days)	$0.09
Standby Charge	(per kVA)	$5.23

Monthly demand 1,000 to 5,000 kW

Customer Charge	(per 30 days)	$754.81
Distribution Charge	(per Max kVA/30 days)	$4.38
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.40
- Connection	(per Max kW/30 days)	$1.77
Transformer Allowance	(per Max kVA/30 days)	$0.62
Rate Rider (per Max kVA/30 days)		$0.07
Standby Charge	(per kVA)	$4.38

Large User
Monthly demand 5,000 kW or greater

Customer Charge	(per 30 days)	$2,902.06
Distribution Charge	(per Max kVA/30 days)	$3.74
Transmission		
- Network	(per Peak kW/30 days)	$2.50
- Connection	(per Max kW/30 days)	$1.80
Transformer Allowance	(per Max kVA/30 days)	$0.62
Rate Rider	(per Max kVA/30 days)	$0.07
Standby Charge	(per kVA)	$3.74

STREET LIGHTS

Customer Charge	(per service location/30 days)	$0.27
Distribution Charge	(per kVA/30 days)	$3.78
Transmission		
- Network	(per Peak kW/30 days)	$2.75
- Connection	(per Max kW/30 days)	$2.03
Rate Rider	(per kVA/30 days)	$0.08

SMALL UNMETERED SCATTERED LOADS
(E.g. Phone Booths, Sentinel Lights, Bill Boards, Crosswalks and Traffic Lights)

Administration and Processing Per Customer	(per 30 days)	$2.09
Service Charge Per Site	(per connection/30 days)	$0.31
Distribution Charge	(per kWh)	$0.0189
Transmission Charge	(per kWh)	$0.0103
Rate Rider	(per kWh)	$0.0014

SPECIFIC SERVICE CHARGES

Duplicate invoices for previous billing	$15.00
Easement Letter	$15.00
Income Tax Letter	$15.00
Returned cheque charge (plus bank charges)	$15.00
Account set up Charge	$30.00
Special meter reads	$30.00
Collection of account charge – no disconnection	$30.00
Disconnect/Reconnect at meter – during regular hours	$65.00
Install/Removal load control devise – during regular hours	$65.00
Disconnect/Reconnect at meter – after regular hours	$185.00
Install/Removal load control devise – after regular hours	$185.00
Disconnect/Reconnect at pole – during regular hours	$185.00
Disconnect/Reconnect at pole – after regular hours	$415.00
Meter Dispute charge plus Measurement Canada fees (if meter found correct)	$30.00
Specific Charge for Access to the power poles $/pole/year	$22.35
Standby Administration Charge (per customer per month)	$200.00

2006 ELECTRICITY DISTRIBUTION RATE APPLICATION INDEX

CHAPTER 1 – APPLICATION SUMMARY

1.1 Introduction

1. Toronto Hydro–Electric System Limited ("THESL") hereby files with the Ontario Energy Board (the "OEB" or the "Board") its application for 2006 electricity distribution rates, with an effective date of May 1, 2006.

2. In the OEB's May 11, 2005 Report respecting the 2006 Electricity Distribution Rate Handbook ("DRH"), the OEB observed (at p.10) that "a forward test year is the preferred approach to setting cost of service rates." While the OEB determined that "it must establish a practical approach to setting 2006 rates and that a historical test year should be the basis of the 2006 rate applications", the OEB has given applicants the option of filing on the basis of a 2006 forward test year. THESL agrees with the OEB's initial observation, and has prepared an application based on a 2006 forward test year. THESL believes that this approach lends itself to rates that will more accurately reflect its costs of providing distribution service to its customers in 2006, which in turn will lessen the need for retroactive recoveries in subsequent years. For example, THESL anticipates its labour costs increasing in the coming years, as well as depreciation costs, which have already increased significantly. While the OEB has established Tier 1 adjustments that (in part) allow distributors filing historical test year ("HTY") applications to update certain aspects of their costs of service, labour and depreciation

cost changes are specific cost elements that are not included as Tier 1 adjustments.

3. THESL wishes to emphasize, however, that notwithstanding its forward test year ("FTY") application, its ratepayers will see reductions in their distribution rates – THESL's revenue requirement is in fact projected to be approximately $33.2 million lower in 2006 compared to its initial Market Adjusted Revenue Requirement that was phased in over the 2001-2005 period. This is, in large part, a reflection of THESL's success to date in consolidating the individual electricity distributors of the municipalities that comprised the former Metropolitan Toronto into THESL. Not only have costs been managed well, but THESL has also experienced extraordinary improvement in its safety performance. Both of these factors contribute to lower electricity distribution rates.

4. THESL notes that cost reductions have not come at the expense of system reliability, nor will they. THESL is committed to increasing its investments in capital plant in the coming years, and this application speaks to several material capital projects that are planned for 2006 that will maintain the adequacy, reliability and quality of electricity distribution service to THESL's customers. THESL is focused on planning, building and maintaining its distribution facilities to provide a high level of service to all of its customers, and intends to make prudent use of existing and new technologies in order to provide increasingly efficient and effective levels of customer service.

5. Finally, THESL will be working diligently through 2006 to implement its OEB-approved Conservation and Demand Management ("CDM") Plan for 2005-2007, in support of the Ontario Government's desire to

establish a "culture of conservation" in Ontario. The THESL plan provides for $39.8 M in spending on CDM activities, corresponding to the third *tranche* of THESL's OEB-approved Market Adjusted Revenue Requirement. The plan provides for a blend of capital and operating expenditures and contains activities that will both assist THESL in improving its system in areas such as losses, and assist THESL's customers in using electricity more efficiently. Put simply, the plan contains initiatives that THESL believes will bring CDM-related benefits on both sides of the customer connection point.

1.2 Test Year and Application

6. The DRH provides four options to utilities in regard to the form of test year to be used as a cost basis for the derivation of rates. THESL has elected to adopt the FTY approach.

7. The 2006 EDR Model and other supporting documentation have been adapted to report all projected balances for the FTY. The application also includes actual balances for 2002, 2003 and 2004, reflecting restatements to 2002 and 2003 balances as submitted to the OEB in the past.

8. In other areas, THESL conforms as much as possible to the intent and the filing requirements associated with applications that are based on an HTY. Specifically, in preparing its estimates of 2006 cost levels, adjustments have been made to 2004 reported data to remove all material, unusual and non-recurring items to form the basis of 2006 projections.

9. This Application Summary is accompanied by several Schedules setting out information specified in the DRH, as well as an electronic rate determination model and an associated PILs determination model. The OEB-provided 2006 EDR Model and the 2006 OEB Tax Model are adapted where necessary to provide for setting out 2005 and 2006 forecasts.

1.3 Relief Requested

10. THESL hereby makes application to the OEB for authorization to implement the distribution rates and other charges as set out in this Application, effective May 1, 2006.
11. The distribution rates and other charges for which approval is requested are set out in Appendix 1-A.
12. In most instances, the subject distribution rates have already been established by the Board and THESL simply seeks adjustment of their levels. In the case of specific service charges, THESL requests authorization to implement the standard schedule of charges as set out in the Board-issued 2006 Electricity Distribution Rate Handbook ("DRH"), in place of the existing charges.
13. In the case of Standby Facilities rates, THESL seeks approval to harmonize the existing disparate rates according to the methodology proposed herein. These disparate rates were carried over from the period prior to the amalgamation of the current City of Toronto. The process of harmonizing Standby Facilities rates within the amalgamated Toronto Hydro was interrupted in 2002 by the passage of Bill 210.

14. THESL has received correspondence from the Board dated July 5, 2005, concerning retail transmission rate adjustments. Following the procedure set out in that correspondence to evaluate the need for adjustments to its retail rates, THESL requests approval to adjust the Retail Transmission Connection Charge.

15. THESL requests approval to recover additional costs over a twenty-three month period beginning on May 1, 2006, as increments to the existing Board-approved rate riders. These new cost elements consist of 2004 RSVA balances, incremental OEB fees and OMERS pension costs, and Hydro One Low Voltage ("LV") charges.

16. In addition to the foregoing, and in addition to any treatment of the recovery of OEB assessments, THESL requests that the scope of Account 1508 be modified, or that a new variance account be established, to allow the recording, for reconciliation at a later date, of the differences, if any, between the amounts recoverable in THESL's OEB-approved revenue requirement on account of Electrical Safety Authority fees and regulatory costs associated with regulatory proceedings (including, without limitation, intervenor, consultant, and legal costs), and the actual costs incurred by THESL in this regard. The basis for this request is discussed in Chapter 8 of this Summary.

Appendix 1-A

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
PROPOSED SCHEDULE OF RATES
EFFECTIVE MAY 1, 2006

RESIDENTIAL

<u>Standard</u>

Customer Charge	(per 30 days)	$12.62
Distribution Charge	(per kWh)	$0.0162
Transmission Charge	(per kWh)	$0.0102
Rate Rider	(per kWh)	$0.0032

GENERAL SERVICE

Monthly demand of less than 50 kW

<u>Standard</u>

Customer Charge	(per 30 days)	$16.91
Distribution Charge	(per kWh)	$0.0194
Transmission Charge	(per kWh)	$0.0103
Rate Rider	(per kWh)	$0.0015

Monthly demand 50 to 1,000 kW

<u>Non Interval Meters</u>

Customer Charge	(per 30 days)	$26.92
Distribution Charge	(per Max kVA/30 days)	$5.25
Transmission Charge	(per Max kW/30 days)	$3.91
Transformer Allowance	(per Max kVA/30 days)	$0.62
Rate Rider	(per kVA/30 days)	$0.31

<u>Interval Meters</u>

Customer Charge	(per 30 days)	$27.17
Distribution Charge	(per Max kVA/30 days)	$5.23
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.27
- Connection	(per Max kW/30days)	$1.71
Transformer Allowance	(per Max kVA/30 days)	$0.62
Rate Rider	(per Max kVA/30 days)	$0.09
Standby Charge	(per kVA)	$5.23

Appendix 1-A

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
PROPOSED SCHEDULE OF RATES
EFFECTIVE MAY 1, 2006

Monthly demand 1,000 to 5,000 kW

Customer Charge	(per 30 days)	$754.81
Distribution Charge	(per Max kVA/30 days)	$4.38
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.40
- Connection	(per Max kW/30 days)	$1.77
Transformer Allowance	(per Max kVA/30 days)	$0.62
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Large User
Monthly demand 5,000 kW or greater

Customer Charge	(per 30 days)	$2,902.06
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Transmission		
- Network	(per Peak kW/30 days)	$2.50
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Rate Rider	(per Max kVA/30 days)	$0.07
Standby Charge	(per kVA)	$3.74

STREET LIGHTS

Customer Charge	(per service location/30 days)	$0.27
Distribution Charge	(per kVA/30 days)	$3.78
Transmission		
- Network	(per Peak kW/30 days)	$2.75
- Connection	(per Max kW/30 days)	$2.03
Rate Rider	(per kVA/30 days)	$0.08

Appendix 1-A

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
PROPOSED SCHEDULE OF RATES
EFFECTIVE MAY 1, 2006

SMALL UNMETERED SCATTERED LOADS
(E.g. Phone Booths, Sentinel Lights, Bill Boards, Crosswalks and Traffic Lights)

Administration and Processing Per Customer		
	(per 30 days)	$2.09
Service Charge Per Site	(per connection/30 days)	$0.31
Distribution Charge	(per kWh)	$0.0189
Transmission Charge	(per kWh)	$0.0103
Rate Rider	(per kWh)	$0.0014

SPECIFIC SERVICE CHARGES

Duplicate invoices for previous billing	$15.00
Easement Letter	$15.00
Income Tax Letter	$15.00
Returned cheque charge (plus bank charges)	$15.00
Account set up Charge	$30.00
Special meter reads	$30.00
Collection of account charge – no disconnection	$30.00
Disconnect/Reconnect at meter – during regular hours	$65.00
Install/Removal load control devise – during regular hours	$65.00
Disconnect/Reconnect at meter – after regular hours	$185.00
Install/Removal load control devise – after regular hours	$185.00
Disconnect/Reconnect at pole – during regular hours	$185.00
Disconnect/Reconnect at pole – after regular hours	$415.00
Meter Dispute charge plus Measurement Canada fees (if meter found correct)	$30.00
Specific Charge for Access to the power poles $/pole/year	$22.35
Standby Administration Charge (per customer per month)	$200.00

CHAPTER 2 – COMPONENTS OF THE APPLICATION AND SCHEDULES

2.0 Introduction

This application is presented in four sections. The first section, Section A, contains the written application summary and corresponding Schedules. The second section, Section B, presents 2002, 2003 and 2004 historical data in the 2006 EDR Model format. The third section, Section C, presents a hard copy of the completed 2006 EDR Model. The fourth section, Section D, presents a hard copy of the completed 2006 OEB Tax Model.

The application contains all relevant information outlined in the DRH as well as additional information to help the Board review and evaluate the application. The summary is organized wherever possible in a manner consistent with the order and naming convention of the DRH chapters. The summary is divided into chapters that correspond to those of the DRH. Each chapter, where applicable, is comprised of three subsections: 1) narrative; 2) supporting schedules; and 3) Appendices.

2.1.1 Description of THESL

Attached is Schedule 2-1 - Description of THESL - that provides general corporate information.

2.1.2 Corporate Structure

Attached is Schedule 2-2 - Description of THESL - that provides a corporate organizational chart, describes the nature of each affiliate's business, the services provided to and received from each affiliate and corporate eservices shared with THESL.

2.1.3 Audited Financial Statements and Reconciliations

Attached is Schedule 2-3 - Audited Financial Statements and Reconciliations - that provides audited corporate financial statements for 2002, 2003 and 2004. Attached is an addendum to Schedule 2-3 Audited Financial Statements and Reconciliations that provides explanation to reconcile audited corporate financial statements for 2002, 2003 and 2004 to the data submitted for Reporting and Record-Keeping Requirements ("RRR") and entered into the 2006 EDR Model.

2.1.4 Compliance with Licence

THESL confirms that is no special licence condition or exemption in force that affects the review of this Application.

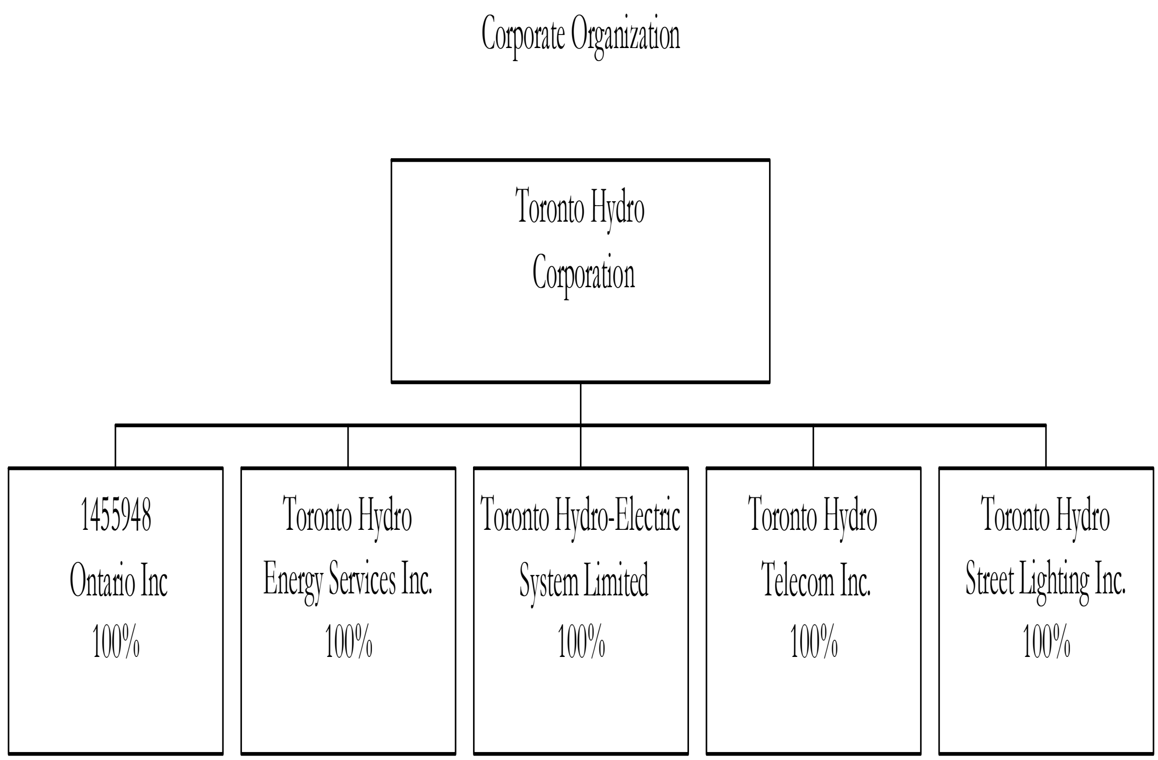
2.1.5 Complete Listing of Rates and Charges

Attached is Schedule 2-4 - Complete Listing of Rates and Charges that provides a complete listing of rates and charges that have been approved by the Board and are currently in effect.

SCHEDULE 2-1: DESCRIPTION OF THESL

Name of Distributor:	Toronto Hydro-Electric System Limited
License Number:	ED-2002-0497
Community Served:	City of Toronto
Adjacent Distributors:	Veridian Connections Inc.; PowerStream Inc.; Enersource Hydro Mississauga; Hydro One Brampton
Service Area Characteristics:	High Density Urban, Urban, and Suburban
Supply Status:	Transmission connected with minor embedded supply from Hydro One Distribution
Mailing Address:	14 Carlton Street, Toronto, Ontario M5B 1K5
Contact Person:	Mr. R. Zebrowski Vice President, Regulatory Services tel: 416.542.2572 fax: 416.542.2776 e-mail: regulatoryaffairs@torontohydro.com

SCHEDULE 2-2: CORPORATE ORGANIZATION CHART



Nature of Affiliate Businesses

Toronto Hydro Corporation

1. Toronto Hydro Corporation ("THC") is a holding company that wholly owns Toronto Hydro-Electric System Limited, Toronto Hydro Energy Services Inc., Toronto Hydro Telecom Inc., Toronto Hydro Street Lighting Inc. and 1455948 Ontario Inc. THC is wholly owned by the City of Toronto.

Toronto Hydro-Electric System Limited

2. Toronto Hydro-Electric System Limited ("THESL") was incorporated under the Ontario Business Corporations Act on June 23, 1999. Its principal business is the distribution of electricity in the City of Toronto.

Toronto Hydro Energy Services Inc.

3. Toronto Hydro Energy Services Inc. ("THESI") was incorporated under the Ontario Business Corporations Act on June 23, 1999. THESI currently holds electricity retailer, marketer, wholesaler and generator licenses, manages an existing portfolio of electricity contracts, and is engaged in the development and sale of energy efficiency products and services.

Toronto Hydro Telecom Inc.

4. Toronto Hydro Telecom Inc. ("THTI") was incorporated under the Ontario Business Corporations Act on September 26, 2000. It provides 'dark' fibre optic capacity and 'lit' data communications services to its customers.

Toronto Hydro Street Lighting Inc.

5. Toronto Hydro Street Lighting Inc. ("THSLI") was incorporated under the Ontario Business Corporations Act on December 28, 2001. It provides street lighting services and related ancillary services to its customers.

1455948 Ontario Inc.

6. 1455948 Ontario Inc. was incorporated under the Ontario Business Corporations Act on December 21, 2000. It is a partner with OPG EBT Holdco Inc. in the EBT Express Partnership. EBT Express Partnership own a majority of the shares in The SPi Group Inc. which operates the main electricity data communication HUB system in the Province of Ontario.

Products and Services Transacted Between THESL and Affiliates

7. THESL provides Facilities, Fleet, Procurement services and Information Technology assets to THC, THESI, THTI and THSLI. In addition, it provides water heater management and maintenance services to THESI.

8. THTI provides Internet services to THESL and other affiliates and THSLI provides Construction, Connection, Line Protection, Insulator Washing and Street Lighting Design services to THESL.

9. THESL has entered into Service Agreements ("SAs") in each of those areas with each of THC, THESI, THTI and THSLI. The SAs set out the services to be provided by THESL and the corresponding cost to the affiliate.

10. All of the arrangements concerning services supplied by THESL comply with the Affiliate Relationships Code.

Shared Services

11. THC provides several shared services to THESL and other affiliates. These services include Finance, Treasury, Risk Management, Rates, Human Resources, Organizational Development and Performance, Environment, Health and Safety, Legal, Regulatory Services, Communications, Corporate Governance and Information Technology Support Services.

12. THESL has concluded SAs in each of the subject areas with THC. The SAs set out the services to be provided to THESL and the corresponding cost to THESL.

13. All of the arrangements concerning services provided to THESL comply with the Affiliate Relationships Code.

SCHEDULE 2-3: AUDITED FINANCIAL STATEMENTS

1. Attached are the THESL audited financial statements for the years ended December 31, 2004, restated December 31, 2003 and restated December 31, 2002.

2. For the year ended December 31, 2002, the Statement of Retained Earnings, Statement of Income and Statement of Cash Flows have been provided. The December 31, 2002 restated financial statements exclude the audited Balance Sheet.

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2004

Financial Statements

Toronto Hydro-Electric System Limited

DECEMBER 31, 2004

Contents **Page**

ERNST & YOUNG

AUDITORS' REPORT

To the Shareholder of
Toronto Hydro-Electric System Limited

We have audited the balance sheets of **Toronto Hydro-Electric System Limited** [the "Corporation"] as at December 31, 2004 and 2003 and the statements of retained earnings, income and cash flows for each of the years in the three-year period ended December 31, 2004. 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 financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Toronto, Canada,
March 4, 2005 [except as to note 23,
which is as of March 31, 2005].

Chartered Accountants

Toronto Hydro-Electric System Limited

BALANCE SHEET

[in thousands of dollars]

As at December 31

	2004	2003
	$	$
		[restated]
ASSETS		
Current		
Cash and cash equivalents	**289,125**	206,158
Accounts receivable, net of allowance for doubtful accounts *[notes 5 and 17]*	**143,249**	149,454
Unbilled revenue *[note 17]*	**233,270**	236,153
Inventories	**19,373**	22,491
Prepaid expenses	**81**	271
Total current assets	**685,098**	614,527
Long-term loan receivable from related party *[note 17]*	**-**	6,991
Property, plant and equipment, net *[note 6]*	**1,518,186**	1,537,399
Intangible assets, net *[note 7]*	**45,329**	51,500
Regulatory assets *[note 8]*	**71,003**	86,032
Other assets *[note 9]*	**3,685**	4,618
Total assets	**2,323,301**	2,301,067
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities *[notes 5 and 17]*	**278,186**	277,164
Promissory note payable *[note 11]*	**980,231**	980,231
Current portion of other long-term liabilities *[note 10]*	**16,557**	14,020
Total current liabilities	**1,274,974**	1,271,415
Long-term liabilities		
Long-term note payable to related party *[note 17]*	**180,000**	180,000
Post-employment benefits *[note 12]*	**108,397**	103,677
Customers' advance deposits and other deposits	**45,967**	42,522
Asset retirement obligations *[notes 3[k] and 13]*	**4,274**	4,040
Other long-term liabilities *[note 14]*	**4,007**	4,666
Total long-term liabilities	**342,645**	334,905
Total liabilities	**1,617,619**	1,606,320
Commitments and contingencies *[notes 18, 20 and 21]*		
Shareholder's equity		
Share capital *[note 15]*	**527,817**	527,817
Retained earnings	**166,474**	155,539
Contributed surplus	**11,391**	11,391
Total shareholder's equity	**705,682**	694,747
Total liabilities and shareholder's equity	**2,323,301**	2,301,067

STATEMENT OF RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31

	2004	2003	2002
	$	$	$
		[restated]	*[restated]*
Retained earnings, beginning of year			
As previously reported	**155,539**	80,696	7,339
Change in accounting policy *[note 3[k]]*	**-**	4,044	-
As restated	**155,539**	84,740	7,339
Net income	**60,135**	75,799	73,357
Dividends *[notes 15 and 23]*	**(49,200)**	(5,000)	-
Retained earnings, end of year	**166,474**	155,539	80,696

Toronto Hydro-Electric System Limited

STATEMENT OF INCOME

[in thousands of dollars]

Year ended December 31

	2004	2003	2002
	$	$	$
		[restated]	*[restated]*
Revenues *[note 17]*			
Sale of electricity	**2,235,154**	2,374,635	2,385,257
Other income	**27,240**	22,212	4,822
	2,262,394	2,396,847	2,390,079
Costs *[note 17]*			
Purchased power	**1,798,008**	1,934,501	1,960,852
Operating expenses	**166,617**	159,569	160,775
Depreciation and amortization	**122,526**	117,682	121,994
	2,087,151	2,211,752	2,243,621
Income before interest and provision for payments in lieu of corporate taxes	**175,243**	185,095	146,458
Interest income	**10,325**	12,555	2,428
Interest expense			
Long-term notes *[note 17]*	**(78,673)**	(67,091)	(66,656)
Other interest	**(2,935)**	(13,049)	(4,520)
Income before provision for payments in lieu of corporate taxes	**103,960**	117,510	77,710
Provision for payments in lieu of corporate taxes *[note 16]*	**43,825**	41,711	4,353
Net income	**60,135**	75,799	73,357

Toronto Hydro-Electric System Limited

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31

	2004	2003	2002
	$	$	$
		[restated]	*[restated]*
OPERATING ACTIVITIES			
Net income	**60,135**	75,799	73,357
Adjustments for non-cash items			
Depreciation and amortization	**122,526**	117,682	121,994
Net change in other liabilities and assets	**3,835**	(1,229)	(3,557)
(Loss) gain on disposal of property, plant and equipment	**(1,043)**	(397)	236
Changes in non-cash working capital balances			
Decrease (increase) in accounts receivable	**6,205**	24,243	(36,579)
Decrease (increase) in unbilled revenue	**2,883**	6,463	(78,190)
Decrease (increase) in inventories	**3,118**	(2,259)	3,989
Decrease (increase) in prepaid expenses	**190**	591	(435)
Increase in accounts payable and accrued liabilities	**1,022**	4,147	24,727
Increase in current portion of long-term liabilities	**1,717**	1,711	1,673
Net cash provided by operating activities	**200,588**	226,751	107,215
INVESTING ACTIVITIES			
Purchase of property, plant and equipment	**(92,894)**	(96,143)	(103,794)
Purchase of intangible assets	**(6,848)**	(4,727)	(12,049)
Decrease (increase) in regulatory assets	**15,029**	(3,963)	(51,036)
Decrease (increase) in notes receivable from related parties	**-**	71,729	(71,729)
Decrease in long-term loan receivable from related party	**6,991**	13,074	-
Proceeds on disposal of property, plant and equipment	**5,397**	476	4,982
Net cash used in investing activities	**(72,325)**	(19,554)	(233,626)
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness and bankers' acceptances	**-**	(210,000)	151,455
Increase in customers' advance deposits	**5,795**	7,788	7,160
Increase in deferred debt issue costs	**-**	(2,988)	-
Repayment of capital lease liability	**(1,891)**	(1,775)	(1,268)
Dividend paid *[note 15]*	**(49,200)**	(5,000)	-
Increase in long-term note payable to related party	**-**	180,000	-
Net cash provided by (used in) financing activities	**(45,296)**	(31,975)	157,347
Net increase in cash and cash equivalents	**82,967**	175,222	30,936
Cash and cash equivalents, beginning of year	**206,158**	30,936	-
Cash and cash equivalents, end of year	**289,125**	206,158	30,936
Supplementary cash flow information			
Total interest paid	**79,889**	75,486	71,731
Payments in lieu of corporate taxes	**52,828**	5,253	3,808

NOTES TO FINANCIAL STATEMENTS

[all tabular amounts in thousands of dollars]

December 31, 2004

1. INCORPORATION

On June 23, 1999, Toronto Hydro Corporation [the "Corporation"] was incorporated under the Business Corporations Act (Ontario) ["BCA"] along with two wholly-owned subsidiary companies, Toronto Hydro-Electric System Limited ["THESL"] and Toronto Hydro Energy Services Inc. ["THESI"]. 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 electricity distribution to THESL in consideration for the issuance of equity securities of THESL and long-term notes payable to the City.

The equity securities of THESL 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.
THESL distributes electricity to customers located in the City.

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.

Open Access

On May 1, 2002, the Province of Ontario 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, THESL and other electricity distributors have been purchasing their electricity requirements from the wholesale market administered by the Independent Electricity System Operator [the "IESO"] and recovering the cost of electricity and certain other costs at a later date in accordance with procedures mandated by the Ontario Energy Board [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 fulfill obligations to connect and service customers.

THESL 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):

[a] *Electricity Price*. The electricity price represents a pass through of the commodity cost of electricity. See "Price protection and rate caps" below.

The volume of electricity consumed by THESL's customers during any period is governed by events largely outside THESL'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).

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

[c] *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.

[d] *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.

THESL is required to satisfy and maintain prudential requirements with the IESO which include credit support with respect to outstanding market obligations.

Price protection and rate caps

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. In December 2002, the Province passed Bill 210 which, among other things:

[a] fixed the price of electricity payable by consumers of electricity who annually utilize less than 250,000 kWh ["Low Volume Consumers"] and consumers comprised principally of municipalities, universities, schools, hospitals, charities, health and community service organizations, consumers with a demand of 50 kW or less and multi-unit residential buildings ["Designated Consumers"] at 4.3¢ per kWh (retroactive to May 1, 2002);

[b] capped distribution rates at current levels and deferred rate increases and certain cost recoveries by electricity distributors (including scheduled third adjustment for market-based rate of return); and

[c] deemed certain costs and variance account balances of distributors to be "regulatory assets" which are required to be reflected in a distributor's balance sheet until the manner and timing of disposition is determined by the OEB.

In November 2003, the Province:

[a] announced its intention to increase (effective April 1, 2004) 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¢ per kWh thereafter;

[b] directed the OEB to develop new pricing mechanisms (to take effect no later than May 1, 2005) for setting the price of electricity payable by Low Volume Consumers and Designated Consumers; and

[c] announced initiatives with respect to the recovery of regulatory assets and the third distribution rate adjustment to achieve a market-based rate of return.

During the period that the price protection is in effect, it is expected that electricity distributors will be compensated by the Ontario Electricity Financial Corporation for amounts by which the purchase price of the electricity purchased by them in the IESO-administered wholesale market on behalf of Low Volume Consumers and Designated Consumers is greater than the fixed price per kWh charged to customers.

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 market-based rate of return. The adjustment was being phased in over three adjustment periods (2001, 2002 and 2003) to lessen the impact on customers. Effective on each of December 1, 2000 and March 1, 2002, the OEB authorized THESL to increase its distribution rates to allow for the recovery of additional annual revenue of $39.8 million.

On January 17, 2005, THESL 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 adjustment necessary to achieve a market-based rate of return). As mandated by the OEB in December 2004, the rate increase is subject to a financial commitment by THESL to invest $39.8 million in conservation and demand management activities over the next three years.

Regulatory assets

Under Bill 210, electricity distributors are required to reflect certain prescribed costs on their balance sheets until the manner and timing of disposition is determined by the OEB. These costs are:

[a] transition costs resulting from the ramp-up to Open Access;

[b] variances between the cost of electricity purchased by THESL from OPG and the revenue that THESL was permitted to receive for electricity supplied by it to customers during the period January 1, 2001 to April 30, 2002; and

[c] variances between amounts charged by THESL to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by it in the wholesale market administered by the IESO.

See note 2, note 3[a] and note 8.

In November 2003, the OEB announced its intention to permit electricity distributors to make rate applications to the OEB with respect to the recovery of regulatory assets. The recoveries are being phased in over a three-year period which commenced in March 2004.

In September 2004, a public hearing was held to review THESL's regulatory assets for prudence and make a final determination of the amounts to be recovered. On December 9, 2004, the Corporation received the OEB's decisions in regard to the hearings which provided authorization to recover all regulatory asset balances as of December 31, 2003. On January 17, 2005, THESL filed the related rate application with the OEB for the recovery of the approved regulatory assets.

Electricity sector reorganization

In December 2004, the Province initiated a further restructuring of Ontario's electricity industry with the passage of the *Electricity Restructuring Act, 2004*. The restructuring was intended, among other things, to ensure efficient and effective management of electricity, promote the expansion of new electricity supply and capacity, encourage electricity conservation and renewable energy and regulate prices in parts of the electricity sector.

The *Electricity Restructuring Act, 2004*:

[a] established the Ontario Power Authority [the "OPA"], an independent, non-profit, self-financed corporation, with a broad mandate to ensure adequate long-term electricity supply in the Province;

[b] reorganized the Independent Electricity Market Operator as the IESO, a non-share corporation, which will continue to operate the wholesale market and be responsible for the operation and reliability of the integrated power system; and

[c] established a Conservation Bureau within the OPA responsible for assuming a leadership role in planning and coordinating electricity conservation measures and load management in the Province.

Under the *Electricity Restructuring Act, 2004*, the commodity cost of electricity for certain customer classes will be determined by the OEB on an annual basis based on a combination of regulated (i.e., electricity generated by existing generation assets principally owned by OPG), contract (i.e., new capacity under contract between generators and the OPA) and competitive market (i.e., spot market) prices for electricity. Customers that do not wish to or are not eligible to participate in the regulated plan may purchase electricity in the competitive market or through licenced retailers.

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, including payments in lieu of corporate taxes ["PILs"] recoveries, that THESL may charge and the costs that THESL may recover, including the balance of its regulatory assets.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements of THESL 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 a non-regulated environment:

Regulatory assets

Under Bill 210, certain costs and variance account balances are deemed to be "regulatory assets" and are reflected in THESL's balance sheet until the manner and timing of disposition is determined by the OEB. The principal regulatory assets of THESL are comprised of transition costs, a pre-market opening energy variance, settlement variances and other regulatory assets.

[a] Transition costs:
Costs incurred to align systems and practices with the requirements of the competitive electricity market in Ontario in accordance with the Act have been deferred in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the AP Handbook. Under such regulation, certain costs are allowed to be deferred that would be expensed when incurred under Canadian GAAP for unregulated businesses *[note 8]*.

Effective January 1, 2003, transition costs have been increased for the capitalized OEB prescribed rate of return and calculated and recorded using simple interest on the carrying value, in accordance with criteria set out in the AP Handbook. The offsetting credit is recorded as interest income.

[b] Pre-market opening electricity variance:
At December 31, 2004, THESL recognized the pre-market opening electricity variance for the period January 1, 2001 to April 30, 2002, the date of market opening, in accordance with the AP Handbook *[note 8]*. The pre-market opening variance represents the difference between the utility'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.

In December 2004, the pre-market opening electricity variance has been increased for capitalized carrying costs, calculated and recorded using simple interest on the carrying value for the period January 1, 2001 to December 31, 2004, in accordance with a December 9, 2004 OEB Decision.

[c] Settlement variances:
THESL has recognized settlement variances for the period May 1, 2002 to December 31, 2004 in accordance with criteria set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges and imported power charges *[note 8]*. The nature of the settlement variances is such that the balance will fluctuate between assets and liabilities over time and are reported at period-end dates in accordance with rules prescribed by the OEB.

Settlement variances costs are increased for capitalized carrying costs, calculated and recorded using simple interest on the carrying value, in accordance with criteria set out in the AP Handbook. The offsetting credit is recorded as interest income.

[d] Other regulatory assets:
Commencing in 2004, the OEB has allowed for the deferral of OEB Annual Cost Assessments for the OEB's fiscal year 2004 and subsequent fiscal years in accordance with criteria set out in the OEB's AP Handbook. Under such regulation, certain costs are allowed to be deferred that would be expensed when incurred under Canadian GAAP for unregulated businesses *[note 8].* Subject to OEB review, THESL will be able to recover the amounts deferred beginning in 2006.

THESL continually assesses the likelihood of recovery of regulatory assets. If full recovery through future rates was no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment was made. For any future recovery decisions made by the OEB or the Minister of Energy to allow recovery of the regulatory assets, the recovery is accounted for based upon the nature of the regulatory assets and the accounting treatment applied initially recognize such regulatory assets.

Business Protection Plan ["BPP"]

Consumers other than designated consumers who annually utilize more than 250,000 kWh are eligible to receive BPP rebates from IESO to the extent that electricity prices exceed certain prescribed thresholds.

THESL and other electricity distributors are required to pass these rebates through to eligible consumers and other market participants (including retailers). THESL includes amounts due from IESO in accounts receivable and includes amounts due to eligible consumers and market participants in accounts payable and accrued liabilities.

Payments in lieu of corporate taxes

THESL is exempt from tax under the *Income Tax Act (Canada)*, if not less than 90% of its capital is owned by the City and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City. A corporation exempt under the *Income Tax Act (Canada)* is also exempt from tax under the *Corporations Tax Act.*

THESL is a “municipal electric utility” [“MEU”] 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 *Income Tax Act (Canada)* and the *Corporations Tax Act* is required to make, for each taxation year, a payment in lieu of corporate taxes, comprised of income tax and large corporation tax, to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay under the *Income Tax Act (Canada)* and the *Corporations Tax Act* if it were not exempt from tax.

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 [“CICA”] and the OEB.

The OEB's Electricity Distribution Rate Handbook provides for the recovery of PILs by THESL 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 is tracked by THESL as a variance amount in accordance with OEB guidelines for regulatory assets and with criteria set out in the AP Handbook.

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.

Contributions in aid of construction

Capital contributions are required contributions received from outside sources used to finance additions to property, plant and equipment. 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 and meters

Spare transformers and meters are items that are expected to substitute for original distribution plant transformers and meters 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. Spare transformers and meters are treated as capital assets *[note 6].*

b) Cash and cash equivalents

Cash equivalents are highly liquid investments with terms to maturity of five months or less from their date of acquisition. Temporary investments are accounted for at the lower of cost and market.

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) Deferred debt issue costs

During 2003, THESL 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 9].* 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.

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 income.

[all tabular amounts in thousands of dollars]

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%
Distribution stations	2.9% to 5.0%
Distribution lines - overhead and underground	2.5% to 4.0%
Distribution transformers	3.3% to 4.0%
Distribution 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 20.0%
Equipment and tools	10.0%

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

f) Intangible assets

Intangible assets, 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 paid	4.0%

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

g) Workplace Safety and Insurance Act

THESL is a Schedule 1 employer for workers' compensation under the Workplace Safety and Insurance Act [“WSIA”]. As a Schedule 1 employer, THESL 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.

Other income revenues, which include revenues from electricity distribution services, pole attachment, duct rentals and other miscellaneous revenues, are recognized as the service activity is performed.

i) Employee future benefits

Pension plan

THESL provides a pension plan for its full-time employees through the 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. THESL 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 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.

Effective January 1, 2003, THESL transferred employees associated with the Corporation and transferred their proportionate share of the accrued benefit obligation of $4,756,000 *[note 12].* The proportionate share was determined based on active employee data used for the current actuarial valuation.

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 income for 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

Effective January 1, 2004, THESL adopted the new CICA standard for accounting for asset retirement obligations [“ARO”]. Under the new standard, THESL 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 ARO is incurred.

[all tabular amounts in thousands of dollars]

The effect of the adoption of the new standard was recorded retroactively with the restatement of the year ended December 31, 2003 and an adjustment to January 1, 2003 opening retained earnings. The effect of the adoption is presented below:

	January 1, 2003 $
Balance sheet:	
Property, plant and equipment - ARO assets *[note 6]*	3,125
Property, plant and equipment - accumulated depreciation on ARO assets *[note 6]*	(89)
ARO liability	(3,125)
Provision for environmental costs liability – current portion	800
Provision for environmental costs liability – long-term	3,333
Opening retained earnings	4,044

	Year ended December 31 2004 $	**2003 $**
Statement of income:		
Operating expenses - reversal of future removal and site restoration accrual	—	**(1,618)**
Operating expenses - accretion expense	**235**	**193**
Depreciation and amortization	**121**	**103**
Net income	**356**	**(1,322)**

l) Use of estimates

The preparation of THESL'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.

4. AMENDED AND RESTATED RESULTS FOR 2003 AND 2002

In May 2004, the IESO informed LDC of a variance in consumption data recorded at the Ellesmere wholesale metering sub-station. In August 2004, LDC received its monthly wholesale power invoice from the IESO which included a credit in connection with the variance in consumption data for the period of May 1, 2002 to January 31, 2004. Following notification by the IESO of the metering variance, LDC commenced an in-depth review of its revenue, cost of power and regulatory assets calculation model and related market assumptions.

As a result of the findings from this review and the adjustment received from the IESO, the Corporation restated its consolidated financial statements as at and for the years ended December 31, 2003 and 2002. The restatement was recorded to correct for:

[a] Net revenue and regulatory asset variances caused by over-billings for electricity purchased during the relevant period from the wholesale market administered by the IESO as a result of a third party metering error at the Ellesmere wholesale metering sub-station;

[b] Changes in underlying assumptions used by LDC during the relevant period to calculate distribution revenue and regulatory assets for electricity distributed to its large customers; and

[c] Changes in the carrying charge allowance for regulatory assets following OEB direction.

[all tabular amounts in thousands of dollars]

The effects of the resulting adjustments – increase or (decrease) - to the originally issued 2003 and 2002 annual consolidated financial statements were recorded retroactively as follows:

Consolidated balance sheet:	**2003** **$**	**2002** **$**
Assets		
Unbilled revenue	15,757	10,023
Regulatory assets	(7,197)	567
Liabilities		
Accounts payable and accrued liabilities	7,081	83

Consolidated statement of income:	**2003** **$**	**2002** **$**
Revenues	(15,136)	4,629
Costs - purchased power	(22,683)	(14,071)
Interest income	1,191	1,148
Provision for PILs	7,259	83
Net income	1,479	10,507

Consolidated statement of cash flows:	**2003** **$**	**2002** **$**
Operating activities:		
Income from continuing operations	1,479	10,507
Changes in non-cash working capital balances		
Increase in unbilled revenue	(15,757)	(10,023)
Increase in accounts payable and accrued liabilities	7,081	83
	(7,197)	567
Investing activities:		
Decrease (increase) in regulatory assets	7,197	(567)

The changes in underlying assumptions related to the calculation of distribution revenue, regulatory assets and the changes in the carrying charge allowance for regulatory assets following OEB direction have been reflected in the 2004 financial statements.

[all tabular amounts in thousands of dollars]

5. BUSINESS PROTECTION PLAN REBATES

At December 31, 2004, "Accounts receivable, net of allowance for doubtful accounts" include $44,739,000 [2003 - $26,313,000] receivable from IESO regarding the BPP rebates and "Accounts payable and accrued liabilities" include $33,609,000 [2003 - $15,937,000] payable to customers, electricity retailers and wholesale suppliers in connection with BPP rebates. The remaining $11,130,000 represents the portion allocated to THESI [2003 - $10,376,000; 2002 - $nil].

6. PROPERTY, PLANT AND EQUIPMENT, NET

Property, plant and equipment consist of the following:

	2004			**2003**		
	Cost **$**	**Accumulated Depreciation** **$**	**Net Book value** **$**	**Cost** **$** *[restated]*	**Accumulated Depreciation** **$** *[restated]*	**Net Book value** **$** *[restated]*
Land	**4,153**	**—**	**4,153**	5,871	—	5,871
Buildings	**140,635**	**40,107**	**100,528**	143,360	37,727	105,633
Distribution stations	**177,362**	**88,364**	**88,998**	170,039	82,757	87,282
Distribution lines – overhead and underground	**1,877,718**	**868,982**	**1,008,736**	1,815,429	798,016	1,017,413
Distribution transformers	**451,328**	**230,665**	**220,663**	431,210	215,309	215,901
Distribution meters	**123,007**	**71,585**	**51,422**	119,086	67,524	51,562
Other capital assets	**32,672**	**27,312**	**5,360**	32,387	26,003	6,384
Communications	**21,280**	**17,909**	**3,371**	23,677	18,804	4,873
Computer hardware	**35,560**	**31,566**	**3,994**	32,998	29,142	3,856
Rolling stock	**48,912**	**38,309**	**10,603**	48,969	36,761	12,208
Equipment and Tools	**25,603**	**21,157**	**4,446**	23,542	20,294	3,248
Construction in progress	**15,912**	**—**	**15,912**	23,168	—	23,168
	2,954,142	**1,435,956**	**1,518,186**	2,869,736	1,332,337	1,537,399

[all tabular amounts in thousands of dollars]

At December 31, 2004, spare transformers and meters with carrying amounts of $4,467,000 and $180,000, respectively [2003 - $5,408,000 and $1,111,000, respectively], are included in "Property, plant and equipment, net" *[note 3[a] " Spare transformers and meters"].*

7. INTANGIBLE ASSETS, NET

Intangible assets consist of the following:

	2004			2003		
	Cost $	Accumulated Amortization $	Net Book value $	Cost $	Accumulated Amortization $	Net Book value $
Land rights	**9,946**	**1,615**	**8,331**	9,884	1,417	8,467
Computer software	**88,318**	**54,859**	**33,459**	84,357	41,805	42,552
Capital contributions paid	**2,043**	**34**	**2,009**	—	—	—
Software in development	**1,530**	**—**	**1,530**	481	—	481
	101,837	**56,508**	**45,329**	94,722	43,222	51,500

8. REGULATORY ASSETS

Regulatory assets consist of the following*:*

	2004 $	2003 $
		[restated]
Transition costs	**37,310**	35,077
Pre-market opening energy electricity variance	**22,879**	21,401
Settlement variances	**9,421**	29,554
Other regulatory assets	**1,393**	—
	71,003	86,032

For the year ended December 31, 2004, THESL recovered settlement variances of $17,701,000 through permitted distribution rate adjustments [2003 - $nil] *[notes 2 and 3[a]].*

For the year ended December 31, 2004, interest of $2,254,900 and $2,785,000 was capitalized in the balances above for transition costs and settlement variances, respectively [2003 restated - $2,233,000 and $3,513,000, respectively].

[all tabular amounts in thousands of dollars]

9. OTHER ASSETS

Other assets consist of the following:

	2004 $	2003 $
Deferred debt issue costs, net of accumulated amortization of $493,000 [2003 - $194,000]	**2,496**	2,795
Long-term advances and deposits	**744**	1,378
Other	**445**	445
	3,685	4,618

10. CURRENT PORTION OF OTHER LONG-TERM LIABILITIES

	2004 $	2003 $ *[restated]*
Current portion of obligations under capital leases *[note 18]*	**2,514**	2,328
Customers' advance deposits	**14,043**	11,692
	16,557	14,020

During 2004, $858,000 was charged to interest expense for the interest credited to the customers' deposit accounts [2003 - $1,044,000].

11. PROMISSORY NOTE PAYABLE

THESL 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 THESL 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/common equity structure of THESL [65:35] permitted by the OEB. At the same time, the Initial Note was replaced by a promissory note ["Replacement Note"] issued by THESL, 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 issue by the Corporation to the City of a new promissory note [the "City Note"].

On May 7, 2003, the terms of the Replacement Note, between THESL and the Corporation, were restructured to payable on demand and interest bearing at the Debt Cost Rate ["DCR"] plus 5 basis points. The DCR is a rate of interest per annum that at all times is equal to the debt cost rate prescribed from time to time by the OEB in the OEB Electricity Distribution Rate Handbook for utilities in the same rate class as THESL, which is currently 6.8% per annum. Interest is calculated and payable quarterly in arrears on the last day of March, June, September and December of each year and commenced on June 30, 2003.

12. EMPLOYEE FUTURE BENEFITS

Pension

For the year ended December 31, 2004, THESL's current service pension costs were $5,848,000 [2003 - $1,898,000; 2002 - $nil]. Because of a surplus under the plan, a contribution holiday had been in effect from August 1998 to December 2002. Current service pension cost contributions recommenced in January 2003 at one-third of the full contribution rates. Beginning January 1, 2004, THESL returned to full contribution rates.

Employee future benefits other than pension

THESL has a number of unfunded benefit plans providing retirement and post-employment benefits [excluding pension] to most of its employees.

[a] Medical and life insurance benefits

THESL pays certain medical and life insurance benefits under unfunded defined benefit plans on behalf of its retired employees.

[b] Accumulated sick leave credits

THESL pays accumulated sick leave credits, up to certain established limits based on service, in the event of retirement, termination or death of certain employees.

[all tabular amounts in thousands of dollars]

[c] Voluntary exit incentive program liability

In October 1994, the former Toronto Hydro-Electric Commission introduced the voluntary exit incentive program for eligible employees. Under the terms of the program, certain employees receive a retirement supplement payment over the term of their retirement and the life of any surviving spouse.

[d] Information about THESL's defined benefit plans

THESL 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, 2003. The December 31, 2004 year-end accrued benefit obligation reflects a December 31, 2004 discount rate. This result was achieved by updating the January 1, 2003 actuarial valuation using the December 31, 2004 discount rate of 5.9% while keeping all other assumptions constant.

i) Accrued benefit obligation:

	2004 **$**	**2003** **$**	**2002** **$**
Balance at beginning of year	**113,188**	94,454	93,907
January 1, 2003 transfer of employees to the Corporation	**—**	(4,756)	
January 1, 2002 transfer of employees to the Corporation, Toronto Hydro Telecom Inc. ["THTI"] and Toronto Hydro Street Lighting ["THSLI"]	**—**	—	(1,988)
Current service cost	**1,897**	1,428	1,366
Interest cost	**7,308**	7,057	5,917
Benefits paid	**(5,230)**	(4,592)	(4,748)
Actuarial losses	**11,140**	11,156	—
Plan amendments	**—**	8,441	—
Balance at end of year	**128,303**	113,188	94,454

[all tabular amounts in thousands of dollars]

ii) Reconciliation of the accrued benefit obligation to the balance sheet accrued benefits liability:

	2004 $	2003 $	2002 $
Accrued benefit obligation	**128,303**	113,188	94,454
Unamortized net actuarial (loss) gain	**(13,721)**	(2,581)	8,575
Unamortized past service costs	**(6,185)**	(6,930)	766
Post-employment benefits liability	**108,397**	103,677	103,795

iii) Components for net periodic defined benefit costs:

	2004 $	2003 $	2002 $
Current service cost	**1,897**	1,428	1,366
Interest cost	**7,308**	7,057	5,917
Actuarial losses	**11,140**	11,156	—
Plan amendments	**—**	8,441	—
Elements of employee future benefit costs before Adjustments	**20,345**	28,082	7,283
Adjustments to recognize the long-term nature of employee future benefit costs			
Difference between actuarial loss recognized for year and actuarial loss on accrued benefit obligation for the year	**(11,140)**	(11,156)	—
Difference between amortization of past service costs for the year and actual plan amendments for the year	**745**	(7,696)	(100)
	(10,395)	(18,852)	(100)
Defined benefit costs recognized	**9,950**	9,230	7,183
Capitalized as part of property, plant and equipment	**2,985**	3,046	2,299
Charged to operations	**6,965**	6,184	4,884

[all tabular amounts in thousands of dollars]

iv) Significant assumptions:

	2004 %	2003 %	2002 %
Accrued benefit obligation as of December 31:			
Discount rate	**5.9**	6.5	6.5
Rate of compensation increase	**3.3**	3.3	4.0
Benefit costs for years ended December 31:			
Discount rate	**6.5**	6.5	6.5
Rate of compensation increase	**3.3**	3.3	4.0
Assumed health care cost trend rates at December 31:			
Rate of increase in dental costs	**4.5**	4.5	4.5

For December 31, 2004 and 2003, medical costs are assumed to increase at 10.5% graded down by 1.0% annual decrements to 4.5% in 2009 and thereafter.

For December 31, 2002, medical costs are assumed to increase at 12.0% graded down by 1.6% annual decrements to 4.0% in 2007 and thereafter.

v) 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 2004:

	Increase $	Decrease $
Net periodic benefit cost (at 6.5%)	**1,370**	**(1,684)**
Accrued benefit obligation at December 31, 2004 (at 5.9%)	**18,190**	**(13,703)**

[all tabular amounts in thousands of dollars]

13. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, THESL adopted the new CICA standard for accounting for ARO *[note 3[k]]*. A reconciliation between the opening and closing ARO liability balances is provided below:

	2004 $	2003 $
Balance January 1	**4,040**	3,125
ARO liabilities incurred in the year	**139**	1,233
ARO liabilities settled in the year	**(140)**	(511)
Accretion expense	**235**	193
Balance December 31	**4,274**	4,040

At December 31, 2004, THESL estimates the undiscounted amount of cash flows required over the next ten years to settle the ARO is $5,278,000 [December 31, 2003 - $5,240,000]. Discount rates ranging from 4.91% to 5.93% were used to calculate the carrying value of the ARO liabilities. No assets have been legally restricted for settlement of the liability.

14. OTHER LONG-TERM LIABILITIES

	2004 $	2003 $
Obligations under capital leases *[note 18]*	**3,802**	4,299
Other	**205**	367
	4,007	4,666

During 2004, THESL acquired "Property, plant and equipment" through capital lease transactions totaling $1,615,000 [2003 - $2,061,000; 2002 - $4,079,000]. These non-cash transactions have been excluded from the statement of cash flows.

[all tabular amounts in thousands of dollars]

15. SHARE CAPITAL

Share capital consists of the following:

	2004 $	2003 $
Authorized		
The authorized share capital of THESL 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 2003, the board of directors of THESL declared and paid dividends totaling $5,000,000 to the Corporation.

During 2004, the board of directors of THESL declared and paid dividends totaling $49,200,000 to the Corporation.

[all tabular amounts in thousands of dollars]

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

	2004 $	2003 $	2002 $
		[restated]	*[restated]*
Rate reconciliation			
Income from continuing operations before PILs	**103,960**	117,510	77,710
Statutory Canadian federal and provincial income tax rate	**36.12%**	36.62%	38.62%
Expected taxes on income	**37,550**	43,032	30,012
Increase (decrease) in income taxes resulting from			
Large corporations tax net of surtax	**2,806**	3,665	4,299
Utilization of temporary differences previously not benefited	**(96)**	(8,444)	(22,797)
Other	**3,565**	3,458	(7,161)
Provision for PILs	**43,825**	41,711	4,353
Effective tax rate	**42.16%**	35.50%	5.60%
Components of provision for PILs			
Current tax provision	**43,825**	41,711	4,353
Provision for PILs	**43,825**	41,711	4,353

Balance sheet

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2004, future income tax assets of $227,979,000 [2003 - $232,941,000], based on substantively enacted income tax rates, have not been recorded. As at December 31, 2004, the Corporation has accumulated a deferred PILs amount, representing the difference between actual billings that relate to the recovery of PILs and the OEB-approved PILs, totaling an under-recovery of $13,489,000 [2003 - $13,122,000]. Cumulative interest included in the amount, which was calculated using the DCR as prescribed by the OEB at 6.8% totaled $2,313,000 [2003 - $1,563,000].

[all tabular amounts in thousands of dollars]

17. RELATED PARTIES

	2004 $	2003 $
Long-term loan receivable from related parties		
From THSLI	—	6,991
	—	6,991

During 2004, the long-term loan receivable from THSLI was repaid to THESL.

	2004 $	2003 $
Long-term note payable to the Corporation	**180,000**	180,000

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. At December 31, 2004, the fair value of the long-term note payable is $196,529,000 [2003 - $185,593,000], 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. THESL incurred total debt issue costs of $2,989,000, all incurred in 2003 *[note 9]*.

Included in "Accounts receivable, net of allowance for doubtful accounts" are amounts due from related parties as follows:

	2004 $	2003 $
Due from THTI	**472**	428
Due from THSLI	**148**	431
Due from THESI	—	5,900
	620	6,759

[all tabular amounts in thousands of dollars]

Included in "Accounts payable and accrued liabilities" are amounts due to related parties as follows:

	2004 $	2003 $
Due to the Corporation	**13,259**	4,120
Due to THESI	**11,168**	—
	24,427	4,120

At December 31, 2004, the promissory note of $980,231,000 was payable to the Corporation [2003 – $980,231,000]. For the year ended December 31, 2004, interest expense was paid to the Corporation in the amount of $67,255,000. For the year ended December 31, 2003, interest expense was paid to the City and to the Corporation, in the amounts of $23,208,000 and $43,676,000, respectively, on the promissory note [2002 – interest expense of $66,656,000 was paid to the City] *[note 11]*.

For the year ended December 31, 2004, streetlighting electricity was provided to the City in the amounts of $9,590,000 [2003 - $11,139,000; 2002 - $10,023,000].

During 2004, THESL purchased corporate and management services from the Corporation totaling $80,324,000 [2003 - $75,876,000; 2002 $32,052,000] in the ordinary course of business, with these services charged to operating expenses and measured at their exchange amounts.

During 2004, THESL provided water heater services to THESI totaling $4,624,000 [2003 - $4,241,000; 2002 - $3,451,000], with the recovery of these services charged to operating expenses and measured at their exchange amounts.

During 2004, THESL provided procurement and fleet services to THTI, the Corporation and THSLI in the amounts of $84,000, $1,815,000 and $405,000, respectively, in the ordinary course of business and measured at their exchange amounts.

For the year ended December 31, 2004, THESL incurred property taxes payable to the City of $7,825,000 [2003 - $8,485,000; 2002 - $7,458,000].

For the year ended December 31, 2004, THESL billed THTI pole attachment and duct rental services totaling $4,854,000 [2003 - $4,605,000; 2002 - $7,668,000 at prevailing market prices and normal trade terms.

[all tabular amounts in thousands of dollars]

During 2004, THESL purchased project management services from THESI for $569,000 [2003 - $3,068,000; 2002 - $26,400,000].

During 2004, THESL purchased electricity of $1,065,000 [2003 - $1,004,000; 2002 - $767,000] from THESI. At December 31, 2004, included in “Accounts payable and accrued liabilities” is $277,000 [2003 - $374,000; 2002 - $625,000].

For the year ended December 31, 2004, THESL earned electricity revenues of $230,518,000 [2003 – $275,031,000; 2002 - $169,585,000] from THESI. At December 31, 2004, included in “Unbilled revenue” is $22,412,000 [2003 – $24,562,000] of unbilled revenue due from THESI related to electricity revenues.

18. LEASE COMMITMENTS

Operating lease obligations

As at December 31, 2004, the future minimum annual lease payments under property and computer hardware operating leases with remaining lease terms from one to three years are as follows:

	$
2005	**1,034**
2006	**651**
2007	**191**
Total minimum lease payments	**1,876**

[all tabular amounts in thousands of dollars]

Capital lease obligations

As at December 31, 2004, the future minimum annual lease payments under vehicle capital leases with remaining lease terms from one to seven years are as follows:

	$
2005	**2,514**
2006	**2,156**
2007	**1,518**
2008	**576**
2009	**336**
Thereafter	**102**
Total amount of future minimum lease payments	**7,202**
Less interest	**886**
	6,316
Current portion *[note 10]*	**2,514**
Long-term portion *[note 14]*	**3,802**

19. FINANCIAL INSTRUMENTS

Credit risk

Financial assets expose THESL to credit risk. Credit risk is the loss from non-performance by suppliers, customers or financial counter-parties. At December 31, 2004, 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 and promissory note payable approximates their fair value due to the immediate or short-term maturity of these financial instruments.

20. FINANCIAL GUARANTEES

Participants in the wholesale market for electricity that is administered by the IESO 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, 2004, no parental guarantees have been issued on behalf of THESL [2003 - nil].

At December 31, 2004, $80,000,000 [2003 - $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 THESL.

21. CONTINGENCIES

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 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. THESL is not a party to the Consumers' Gas class action. It is, however, subject to the two class actions described below.

The first is an action commenced against a predecessor of THESL 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 as the parties were awaiting the outcome of the Consumers' Gas class action.

The second is an action commenced against a predecessor of THESL 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 THESL and the definitions of the plaintiff classes are identical in both actions. As a result, any damages payable by THESL in the first action would reduce the damages payable by THESL 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.

THESL 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 THESL 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. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2004 financial statements.

23. SUBSEQUENT EVENTS

Dividends

On March 31, 2005, the board of directors of THESL declared dividends in the amount of $24,026,000. The dividends will be paid on March 31, 2005.

ADDENDUM TO SCHEDULE 2-3: Audited Financial Statements and Reconciliations

The purpose of this schedule is to reconcile the 2004, 2003 and 2002 audited financial statement net income to the respective OEB filed Trial balances, with an explanation of any reconciling items.

<u>THESL audited financial statement Net Income reconciliation:</u>

(in thousands of dollars)

A. For the Year ended December 31, 2004:

<u>Net Income</u>	<u>$</u>
Per audited Statement of Income	60,135
Per OEB Filed Trial Balance – USoA account 3046	<u>61,404</u>
Difference	1,269

The difference of $1,269,000 represents a manual adjustment booked to the December 31, 2004 OEB Trial Balance to reclassify CDM activities to a balance sheet deferral account from THESL operating expenses at December 31, 2004.

B. For the Year ended December 31, 2003:

Net Income	**$**
Per audited Statement of Income	75,799
Per OEB Filed Trial Balance – USoA account 3046	75,798
Difference (rounding)	1

C. For the Year ended December 31, 2002:

Net Income	**$**
Per audited Statement of Income	73,357
Per OEB Filed Trial Balance – USoA account 3046	78,140
Difference (rounding)	4,783

The difference of $4,783,000 represents a manual adjustment booked to the December 31, 2002 OEB Trial Balance to reduce the 2002 operating expenses for 2002 charges related to a retroactive billing adjustment to THESL from THTI for the prior periods of 2001 and 2000[1].

[1] **Per December 31, 2003, THESL "Related Party" financial statement note, note # 18:**

For the year ended December 31, 2002, THTI billed THESL "dark" fibre optic capacity and data communication services totalling $9,725,0000, at prevailing market prices and under normal trade terms. Included in the charges of $9,725,000, were amounts related to fiscal 2001 and 2000 charges of $3,826,000 and $957,000, respectively, which total $4,783,000, to retroactively reflect the terms of a new fibre rental agreement which bills THESL a market rate for the services previously provided by THTI.

<u>RRR Data</u>

A. Trial Balance Information Agrees to OEB Filed Data

The 2002, 2003 and 2004 Trial Balance information provided by OEB Chief Regulatory Auditor on July 8, 2005, was reviewed and all balances were verified to the OEB Trial Balances filed for 2002, 2003 and 2004.

B. PBR Information Agrees to OEB Filed Data

All the 2002, 2003 and 2004 PBR information provided by OEB Chief Regulatory Auditor on July 8, 2005, was reviewed and these row values were verified to the respective PBR information filed for 2002, 2003 and 2004.

SCHEDULE 2-4: COMPLETE LISTING OF (CURRENT) RATES & CHARGES

TIME PERIODS FOR APPLICATION OF TRANSMISSION NETWORK CHARGES

Peak: 0700 to 1900 (local time) Monday to Friday inclusive, except for public holidays
Off-Peak: All other hours

Public Holidays: New Year's Day, Good Friday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Thanksgiving Day, Christmas & Boxing Day

RESIDENTIAL

Standard

Customer Charge	(per 30 days)	$13.64
Distribution Charge	(per kWh)	$0.0173
Transmission Charge	(per kWh)	$0.0104
Rate Rider	(per kWh)	$0.0028

Time of Use

Customer Charge	(per 30 days)	$14.78
Distribution Charge	(per kWh)	$0.0173
Transmission Charge	(per kWh)	$0.0104
Rate Rider	(per kWh)	$0.0028

GENERAL SERVICE

Monthly demands of less than 50 kW

Customer Charge	(per 30 days)	$18.27
Distribution Charge	(per kWh)	$0.0207
Transmission Charge	(per kWh)	$0.0105
Rate Rider	(per kWh)	$0.0012

Monthly demands 50 to 1,000 kW - Non Interval Meters

Customer Charge	(per 30 days)	$28.93
Distribution Charge	(per kVA/30 days)	$ 5.64
Transmission Charge	(per kW/30 days)	$ 4.00
Transformer Allowance	(per kVA/30 days)	($0.62)
Rate Rider	(per kVA/30 days)	$0.26

Monthly demands 50 to 1,000 kW - Interval Meters

Customer Charge	(per 30 days)	$29.23
Distribution Charge	(per kVA/ 30 days)	$ 5.63
Transmission Charge		
- Network	(per Peak kW/30 days)	$ 2.27
- Connection	(per Max kW/30 days)	$ 1.80
Transformer Allowance	(per Max kVA/30 days)	($0.62)
Rate Rider	(per kVA/30 days)	$ 0.05

Monthly demands 1,000 - 5,000 kW

Customer Charge	(per 30 days)	$803.72
Distribution Charge	(per kVA/30 days)	$4.66
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.40
- Connection	(per Max kW/30 days)	$1.86
Transformer Allowance	(per Max kVA/30 days)	($0.62)
Rate Rider	(per kVA/30 days)	$ 0.04

Large User (Monthly demands 5,000 kW or above)

Customer Charge	(per 30 days)	$3,070.72
Distribution Charge	(per kVA/30 days)	$3.95
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.50
- Connection	(per Max kW/30 days)	$1.89
Transformer Allowance	(per Max kVA/30 days)	($0.62)
Rate Rider	(per kVA/30 days)	$0.05

STREET LIGHTS

Customer Charge		
Variable Portion	(per connection/30 days)	$0.29
Distribution Charge	(per kVA/30 days)	$4.08
Transmission Charge		
- Network	(per Peak kW/30 days)	$2.75
- Connection	(per Max kW/30 days)	$2.14
Rate Rider	(per kVA/30 days)	$0.03

SMALL UNMETERED SCATTERED LOADS
(E.g. Phone Booths, Sentinel Lights, Bill Boards, Crosswalks and Traffic Lights)

Administration and Processing	(per Customer/30 days)	$ 2.26
Service Charge	(per connection/30 days)	$ 0.29
Distribution Charge	(per kWh)	$0.0201
Transmission Charge	(per kWh)	$0.0105
Rate Rider	(per kWh)	$0.0012

COGENERATION STANDBY/BACKUP:
These rates were effective before market marketing opening and have been grandfathered.

<u>For any customer with demand less than 5,000 kW and local generation</u>

<u>Etobicoke Office</u>
Standby Facility Charge (per kW/Month of reserved capacity)

Customer owned transformer*	(per kW)	$1.00
Utility owned transformer*	(per kW)	$1.60

*Standby charge will be applied to reserved capacity greater than billing demand.

<u>North York Office</u>
Standby Facility Charge*

Customer owned transformer	(per kW)	$1.00
Utility owned transformer	(per kW)	$1.60

*Applicable to the difference between the greater of the contracted demand or the maximum demand in the previous eleven months, and the billing demand for the current month.

<u>Toronto Office</u>
Standby Facility Charge** (per kW) $1.34

Demand is calculated only if back-up is required at the time of Toronto Hydro's peak.
**Applicable to firm demand above contract demand and should not exceed the manufacturer's rated output of the generator.

<u>York Office</u>
Standby Facility Charge for capacity reserved (per kW) $3.36
(Includes York Office's share @ $1.10/kW/month)

<u>For any customer with demand greater than 5,000 kW and local generation</u>

<u>North York Office</u>		
Standby Facility Charge	(per kW)	$1.00
<u>Toronto Office</u>		
Standby Facility Charge**	(per kW)	$1.34

SPECIFIC SERVICE CHARGES

<u>Customer Administration</u>

Account Set up Charge		$ 8.80
Arrears Certificate		$15.00
Dispute Involvement Charge		$10.00

<u>Non Payment of Account</u>

Overdue Account Interest Charge	- Monthly	1.5%
	- Per Annum	19.56%
Returned Cheque Charge		$15.00
Collection of Account Charge		$ 9.00
Reconnection-during regular working hours		$20.00
Reconnection-after regular working hours		$50.00

<u>Billing Related</u>

Special Meter Reading	$10.00
Duplicate invoices for previous billing	$ 2.00
Micro fiche and other historical data record	$ 3.00

<u>Miscellaneous</u>

Service Calls

- Visits to customer premises for service beyond the meter $25.00 (Plus Materials)
- Timer Control for Water Heater $ 2.90 per month

Debt Retirement Charge	(per kWh)	$ 0.0070
Wholesale Market Service Rate (includes Rural Rate Protection)	(per kWh)	$ 0.0062

<u>Regulated Price Plan (RPP)</u>

For residential, low volume and designated consumers

April 1, 2005 to Oct 31, 2005		
First 750 kWh	(per kWh)	$.0500
Balance kWh	(per kWh)	$.0580
November 1, 2005 to April 30, 2006		
First 1,000 kWh	(per kWh)	$.0500
Balance kWh	(per kWh)	$.0580
RPP Administration Charge	(per customer per 30 days)	$0.25

<u>Retail Service Charges</u>

- 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 charge of $0.30 per month per customer, collected from retailers, for a distributor-consolidated, bill-ready service
- Retailer-consolidated billing avoided cost credit f $0.30 per month, per customer, will be paid to a retailer that chooses retailer-consolidated billing.

<u>Service Transaction Requests (STR)</u>

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

<u>Loss Factors</u>

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	.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

CHAPTER 3 – TEST YEAR AND ADJUSTMENTS

3.0 Introduction

1. As previously noted, THESL is filing this Application for 2006 distribution rates using an FTY, calendar year 2006, as its cost basis. This provides a more realistic view of cost levels expected at the time the new rates come into effect than using as its cost basis an HTY, specifically calendar year 2004, with the specific adjustments available to THESL as described in the DRH.
2. The Application includes projections of all account balances for calendar year 2006. The approach and assumptions used to develop these projections are described in Chapter 4 (Rate Base), Chapter 6 (Distribution Expenses) and Chapter 8 (Revenue Requirement), including any adjustments beyond those permitted as Tier 1 and Tier 2 adjustments for a filing based on an HTY.
3. There are no restatements or changes in accounting policy affecting the opening 2004 balances reported in this filing. In an addendum to Schedule 2-3: Audited Financial Statements and Reconciliations, THESL has explained any necessary reconciliations of audited corporate financial statements for 2002, 2003 and 2004 to the data submitted for RRR and entered into the 2006 EDR Model.

3.1 Historical Test Year versus Forward Test Year

4. As mentioned above, of the four options outlined in the DRH, THESL has elected to use an FTY, calendar 2006, as the cost basis for deriving rates to be effective May 1, 2006.
5. In the prevailing circumstances, THESL forecasts significant differences in the levels of certain component costs within the overall revenue requirement. Labour costs and depreciation represent the most significant cost differences. Costs in these areas are not subject to adjustment under the HTY 'Tier 1' adjustments. Consequently, and as directed in the DRH, THESL must file an FTY Application.

3.2 Tier 1 Adjustments

6. Tier 1 Adjustments are not performed when using an FTY cost basis. Accordingly, completed Schedules 3-1 and 3-2 of the DRH are not applicable and therefore not included as part of this Application.
7. THESL is not seeking in this 2006 rate Application approval of CDM spending incremental to the third tranche amounts. Accordingly, a completed Schedule 3-4 of the DRH is not applicable and therefore not included as part of this Application.
8. All adjustments made to 2004 balances to derive the FTY balance projections are described in Chapter 4 (Rate Base), Chapter 6 (Distribution Expenses) and Chapter 8 (Revenue Requirement).

3.3 Tier 2 Adjustments

9. Tier 2 Adjustments are not performed when using an FTY cost basis. Accordingly, a completed Schedule 3-3 of the DRH is not applicable and therefore not included as part of this Application.

CHAPTER 4 – RATE BASE

4.0 Definition of Rate Base

1. Unadjusted rate base information for the years 2002, 2003 and 2004 is included in this Application, as well as projected balances for years 2005 and 2006 to support the FTY cost basis. The projections reflect both expected capital asset additions as well as depreciation expense on all fixed assets expected in 2005 and 2006.
2. Non-distribution assets are not included in these balances. Any such assets controlled by THC are held by affiliates other than THESL.
3. Under the FTY approach, the rate base used to determine the revenue requirement is defined as net fixed assets calculated as an average of 2005 and 2006 ending balances, plus a working capital allowance that is 15 percent of the sum of the cost of power and controllable expenses, both of which are based on 2006 projected costs.
4. The 2005 and 2006 projections include capitalized amounts for CDM assets, rather than projected deferral account balances. In an FTY cost based situation, the use of deferral account projections (as programmed in the 2006 EDR Model for HTY applications) would unduly reduce the rate base by the amount of unspent third tranche funding.
5. All revenue generated by joint use assets included in the rate base is deducted from the Service Revenue Requirement to derive the Base Revenue Requirement.
6. Leased assets are included where they meet the Canadian "GAAP" standards for classification as capital leases.

4.1 Amortization Rates

7. The amortization rates outlined in Appendix B of the DRH are used for this filing. However, DRH Appendix B is silent on the amortization rates for purchased software assets.

8. Attached in this chapter, as Appendix 4-A, is THESL's Computer Software Capitalization Policy that explains the accounting policy and recommended treatment to account for computer software. Paragraph 1.6 of this policy outlines the amortization rates used by the Applicant for computer software.

4.2. Capital Investments

9. THESL's capital investments consist of investments in both its distribution plant and general plant. These investments are described separately in sections 4.2.1 and 4.2.2 respectively. Smart meters, a special type of distribution plant, are also described separately in section 4.2.3.

10. In order to set the context for presenting planned distribution plant investments, the extent of THESL's distribution plant and the asset management model used to manage the plant are described. This is followed by a description of the capital project pools and a summary of historical and planned investments for 2006. Further description and justification for the capital project pools is provided in Appendix 4-B.

11. General plant and investment in general plant are also described followed by a summary of historical investments and planned investments for 2006. Further description and justification for the proposed general plant investment is provided in Appendix 4-C.

12. The following Table 1 summarizes the historical and projected capital expenditures for combined Distribution Plant and General Plant.

Table 1 - Historical and Projected Capital Expenditures

Capital Investments	2003 Actual ($ 000)	2004 Actual ($ 000)	2005 Projected ($ 000)	2006 Projected ($ 000)
Total (without Smart Meters)	98,846	101,496	130,953	154,640
Total (with Smart Meters)	98,846	101,496	130,953	203,317

4.2.1 Distribution Plant Capital Investments

Description of Distribution Plant

13. THESL operates $1.58 billion of net capital assets comprised primarily of an electricity distribution system that delivers electricity to approximately 673,000 customers located in the City of Toronto. THESL is the largest municipal electricity distribution company in Canada and distributes approximately 18 percent of the electricity consumed in Ontario.

Distribution System

14. Electricity produced at generating stations is moved across transmission lines owned by Hydro One Inc. to terminal stations where the voltage is reduced (or stepped down) to a voltage level more appropriate for distribution. The electricity is then moved by THESL over its

distribution system to transformers where the voltage is further reduced for delivery to customers.

15. THESL's distribution system includes a single control centre, 34 terminal stations, 198 municipal substations, more than 58,000 distribution transformers, 25,000 primary switches, 9,100 kilometres of overhead wires supported by over 159,000 poles and 7,500 kilometres of underground wires.

Control Centre

16. THESL has a single control centre that co-ordinates and monitors the distribution of electricity across its service territory. The control centre is linked to the rest of the distribution system by a voice and data communications network. THESL utilizes Supervisory Control and Data Acquisition ("SCADA") systems to monitor the distribution system. SCADA systems are extensively used to monitor and operate the 27.6 kV & 13.8 kV primary feeders in all service areas except the former East York. In the former Toronto district, the 4.16 kV system is also monitored and operated via SCADA.

Terminal Stations

17. The City of Toronto is supplied via 34 transformer terminal stations; 18 owned by Hydro One, 15 jointly owned by Hydro One and THESL, and one owned solely by THESL. Seventeen of the stations are supplied at 115 kV and the other 17 are supplied at 230 kV. At 19 of the transformer stations voltage is stepped down to 27.6 kV, and at the other 15, to 13.8 kV.

Distribution Transformers and Municipal Substations

18. Electricity is moved from the terminal stations at distribution primary voltages to distribution transformers that are typically located in buildings or vaults, or mounted on poles or surface pads and are used to step down voltages to utilization levels for delivery to customers. The THESL distribution system includes over 58,000 distribution transformers.

19. In addition to the terminal stations at 27.6 kV and 13.8 kV there is also a substantial 4.16 kV system involving 188 stations that are located in various parts of the City of Toronto and that are used to step down electricity primary voltage prior to delivery to customers.

Wires

20. In total, power is distributed at 27.6 kV via 253 feeders, at 13.8 kV via 636 feeders, and at 4.16 kV via 730 feeders. THESL distributes electricity through a network of over 9,100 kilometres of overhead wires supported by over 159,000 poles as well as over 7,500 kilometres of underground wires installed in self-contained cable chambers and duct systems. Voltage is further stepped down to intermediate levels for the use of customers in the City of Toronto via more than 58,000 distribution transformers. These transformers are located in buildings, below grade vaults, surface mounted pads or mounted on the poles.

21. Power is distributed throughout the city via radial, loop, and network systems both in underground and overhead plant configurations.

Meters

22. 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.

Distribution Plant Asset Management

23. 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 that 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 service providers, internal and external, to perform those tasks.

24. 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. In addition, the asset manager is responsible for supply chain management, distribution plant standards and distribution plant material selection. The capital projects summarized in this section and further elaborated on in the following sections have been developed by the asset manager. The asset manager has used methods that have been continually

improved since 1998 in accordance with what THESL believes to be industry best practice.

25. The specifics of project identification and selection are explained in the following sections. To ensure capital projects are completed at the lowest possible cost while at the same time maintaining safe and reliable service, THESL obtains its material and civil construction through a competitive tendering process and uses internal labour and equipment for distribution plant installation.

Capital Project Pools

26. Planned 2006 capital investments are listed in Schedule 4-1: Capital Expenditures. Investment is made through projects that involve a number of different assets. Although the distribution plant capital projects planned for 2006 number in the hundreds, the projects can be divided into pools of similar projects. These pools are: A) Rebuilds and Conversions, B) New Feeders and Upgrades, C) Services, D) Stations, and E) Relocations.

27. Projects in each pool are similar in nature and generally not interdependent but involve performing the same types of activities and installing similar equipment in different locations. The justification for performing the projects is provided on a project pool basis in this filing rather than on a project-by-project basis. Projects within each pool that exceed the materiality threshold of $500,000 are identified.

A. Rebuilds and Conversions

28. THESL maintains its distribution plant according to a thorough assessment that uses a Reliability Centred Maintenance methodology. 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.

29. 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.

30. Projects in this pool, for the most part, benefit customer reliability. After being rebuilt, distribution plant assets are more maintainable and reduce safety risks to the general public and staff as they are designed to current standards. In the case of rebuilds involving voltage conversion, low voltage substation equipment is decommissioned and bypassed with higher energy capacity equipment. The higher voltage distribution equipment has lower energy losses. This has the dual benefits of conserving electricity and saving costs that would ultimately be passed on to customers. This work therefore results in a financial benefit to customers.

B. New Feeders and Upgrades

31. The need to increase the capacity of the distribution system arises primarily due to load growth caused by 1) new customer connections and service upgrades, and 2) incremental growth in the demand of existing customers, and may include replacement of deteriorated equipment.

32. Projects in this pool represent an increase in distribution capacity that benefit many customers. They are not strictly for the benefit of single customers.

33. New feeder and upgrade projects permit customer needs to be met in a reliable way. Available capacity is used as much as possible by periodically reconfiguring existing circuits and equipment. Capacity is increased only once these options have been exhausted. Capacity increases permit THESL to operate equipment within optimal rating parameters and to operate the distribution system according to accepted industry practices. This increases service reliability and allows unimpeded customer growth.

C. Services

34. Individual customers and developers initiate service projects. Prospective customers request new service connections, while existing customers typically request increases to individual service capacity. Service projects are done to meet customer needs and carry out THESL's obligations according to its Conditions of Service. Where the prescribed economic evaluation indicates that the future revenue associated with new services is insufficient to pay for the capital cost and

ongoing maintenance costs of the distribution system expansion, the customer pays the difference in the form of a capital contribution.

D. Stations

35. Station projects deal with equipment that transforms and switches power at electricity bulk transfer points. Due to the high volume of electricity that flows through stations, equipment outages can affect tens of thousands of customers at a time. Although stations have higher reliability performance than most other distribution plant, the need to mitigate station outage risks is a critical and leading reason for carrying out station-related projects.

36. Projects in this pool benefit customers by increasing reliability through the planned mitigation of lower probability but higher impact events on station equipment. Station projects are also commonly aligned with New Feeders and Upgrades as capacity increases in the distribution system generally require increased capacity at an upstream station.

E. Relocations

37. Due to the congested nature of many of the City of Toronto's thoroughfares, distribution plant is located in close proximity to other utility plant as well as to City of Toronto infrastructure. In relocation projects, THESL is requested to relocate its distribution plant to accommodate other utility work or City of Toronto work.

38. Projects in this pool benefit customers by increasing reliability by replacing typically older and usually less reliable plant with permanent relocations that are built to modern standards.

4.2.2 General Plant Capital Investments

Description of General Plant

39. 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: A) computer hardware and software equipment, B) transportation equipment and tools, and C) land, building, fixtures and furnishings.

General Plant Projects

A. Computer Equipment

Computer equipment is used in almost all facets of utility operations and is a key enabler in THESL's initiatives to improve reliability, improve service, and reduce costs. The computer equipment projects planned for 2006 generally fall into one of the following three categories:

1. *Consolidation of various systems used by the six pre-amalgamation utilities to common platforms (e.g. projects to consolidate control rooms).* These projects facilitate the harmonization of work practices, increased levels of safety, improved customer service and cost containment.
2. *Enhancement to outage response and customer service delivery system projects.* These projects are aimed at improving customer satisfaction, increasing service reliability, reducing operating costs and improving outage response (e.g. Outage Management System).

3. *Technology upgrade projects intended to keep the software and hardware environments current.* By adhering to what THESL believes to be general industry best practices, these projects enable THESL to retain technical support for its critical applications, minimize service interruptions, meet new technical standards and control maintenance and other costs (e.g. server and workstation upgrades).

40. Communication and supervisory equipment have been included with computer equipment for the purposes of project description and justification.

B. Transportation Equipment and Tools

41. These projects 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.

C. Buildings and Facilities

42. Projects for buildings and facilities involve the improvement and upgrades needed for continued efficient and safe operation of work centres and offices.

4.2.3 Smart Meters

Project Description

43. 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 approximately 673,000 meters within its service territory. Smart meter deployment involves the installation of the meters, the implementation of the information technology systems required, and the development and implementation of the necessary business processes.

Objectives

44. THESL has two main objectives regarding the Smart Meter Program. One objective is to meet, or ideally improve upon, the Government's timeline with respect to the deployment of smart meters to customers. The other objective is to implement the mandated time-differentiated rate structures in accordance with the government's directives.

Implementation Plan

45. The smart meter deployment project is multi-year and multi-faceted. The important project components that need to be carried out include the following:

Smart Meter Technology Selection

- Specification of metrological and communication requirements to meet the needs of THESL.
- Assessment of available technologies.
- Selection of the most cost effective system, or systems, for implementation (the physical location of the meters will likely require two different technologies).

Systems Implementation

- Selection and implementation of a fieldwork management system to support the high volume of meter deployment
- Implementation of interfaces to the Provincial central meter data management system for the smart meter system and billing system
- Integration of THESL's internal systems with the central meter data management system and the smart meter system
- Modification and enhancement of the billing/settlement/EBT systems to support the mandated meter data and rate structures

Business Process Implementation

- Development and implementation of business processes impacted by smart metering in the areas of billing, customer service, meter services, etc.

Meter Deployment

- Planning of meter installation work schedule to meet installation targets (the deployment strategy will likely require focusing on the non-downtown areas first to meet the installation targets)
- Planning of resources for the work volumes required
- Development and implementation of meter installation and data update processes
- Dispatching, management and tracking of meter installations

Customer Communication

- Development of a communication plan to inform and educate customers regarding smart meter and time-of-use rates
- Implementation of a customer communication plan

Table 2 Projected 2006 Smart Meter Expenditures

	Residential	**Commercial & Industrial**	**Total**
Number of Smart Meters Installed	150,000	7,500	$157,500
Material Cost	$34,375,000	$9,567,000	$43,942,000
Labour Cost	$2,575,000	$1,480,000	$4,055,000
Vehicle Cost	$500,000	$180,000	$680,000
IT Cost	$2,857,000	$143,000	3,000,000
Totals	**$40,307,000**	**$11,370,000**	**$51,677,000**

Notes:

a) System costs pertaining to the implementation of the smart metering system and fieldwork management system are included in the above summary. System costs related to billing system, interfaces, and back-office systems integration are not included at this time, as the roles of distributors, the Ontario Government, and other agencies and/or third parties is not yet clear. If THESL and other distributors are to be involved in these activities, it will be necessary for them to recover the associated costs.

b) The Customer Communication Cost will be a one-time expense for educating customers on smart metering.

c) Installed Meter Unit Cost is $250 for Residential smart meters and $1500 for Commercial & Industrial interval meters, based on the OEB Implementation Plan dated January 26, 2005, Appendix C-2. Monthly Operating Unit Cost of $1.42 and Benefit of $0.39 are taken from the same Appendix.

d) A 15-year depreciation period has been used.

4.3 Interest on Deferral Accounts and Construction Work in Progress

46. The interest rate used for deferral accounts is the rate set by the OEB at the time the deferral account is established. THESL does not use any Allowance for Funds Used During Construction in its account balances.

4.4 Capitalization Policy

47. Attached in this chapter, as Appendix 4-D, is a document outlining THESL's capitalization policy for property, plant and equipment and intangible properties.

48. As mentioned earlier in section 4.1, attached in this chapter, as Appendix 4-A, is THESL's Computer Software Capitalization Policy that explains

the accounting policy and recommended accounting treatment for computer software.

4.5 Contributed Capital

49. Contributed capital collected by THESL on or after January 1, 2000 is not included in the calculation of rate base, and associated amortization is not charged to distribution expenses.
50. Contributed capital included in the rate base under the Ontario Hydro regulatory regime remains in the rate base, and associated amortization is charged to distribution expenses, until such assets are fully depreciated.

4.6 Treatment of Capital Gains and Losses

51. No gains or losses on non-depreciable property are included in the FTY projections, from which the base revenue requirement is determined. In 2004, THESL recognized gains of $958,821 from substation disposals.
52. The only capital gains included in the future year projections result from vehicle disposals in the ordinary course of business, based on the actual gains realized in 2004.
53. The gains or losses realized in each of 2002, 2003 and 2004, as well as those projected for 2005 and 2006, are below the materiality threshold specified in section 4.2 of the DRH. THESL has included 100 percent of the proceeds in Other Revenues.

SCHEDULE 4-1: CAPITAL EXPENDITURES

Additions to Asset Accounts	2003 Actual ($000)	2004 Actual ($000)	2005 Projected ($000)	2006 Projected ($000)
Intangible Plant	4,728	6,848	0	0
Distribution Plant				
1805 Land Substation	0	0	220	0
1806 Land Rights	0	0	-55	5
1808 Bld - Substation	721	-12	682	440
1830 Poles, Towers and Fixtures	25,460	10,031	2,061	13,474
1835 Overhead Conductors and Devices	6,842	8,249	887	14,392
1840 Underground Conduit	20,258	24,789	44,675	47,873
1845 Underground Conductors and Devices	28,124	25,678	27,517	27,223
1850 Line Transformers	45,507	31,891	32,936	27,924
1855 Services	9,183	10,123	1,163	1,208
1860 Meters	-1,487	4,087	870	5,986
1860 Smart Meters	0	0	0	48,677
1820 Distribution Station	2,838	5,739	6,214	6,892
General Plant				
1905 Land, Admin & Service	0	0	235	0
1906 Land Rights	0	0	-290	29
1908 Buildings and Fixtures	-30	685	1,858	1,200
1910 Lease IMP	5	0	0	0
1915 Office Furniture	185	206	179	311
1920 Computer Equipment Hardware	-7,251	2,563	1,257	1,790
1925 Computer Software	11,230	0	7,460	17,642
1930 Transportation Equipment	5,979	1,585	968	559
1935 Stores Equipment	0	77	0	0
1940 Tools, Shop and Garage Equipment	161	2,011	2,733	1,002
1945 Testing Equipment	484	50	573	210
1955 Commuication Equipment	393	736	21	563
1960 Misc Equipment	0	0	1,324	0
1970 Load Mgmt Controls - Cust	0	0	1,534	0
1975 Load Mgmt Controls - Utilities	0	0	217	0
1980 System Supervisory	210	1,666	4	2,025
1985 Sentinel Lighting Rental units	0	0	-4	0
1995 Capital Contributions	-18,334	-28,519	-16,281	-22,000
CWIP	-36,647	-6,989	11,995	5,892
Other Capital Assets	0	0	0	0
Total Capital Expenditures	98,559	101,494	130,953	203,317

APPENDIX 4-A: COMPUTER SOFTWARE CAPITALIZATION POLICY

ACCOUNTING POLICIES

SUBJECT: Computer Software Capitalization Policy	2002/03/12 V 00	SECTION A1000

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.

(Specify the subjects within the scope or the range of the accounting policy, if applicable. Not applicable.)

1.3 Definitions

1.3.1 Software are computer programs, written in machine-readable language, that control the operations hardware or that enable users to perform certain tasks on the computer. The two principle categories of software are systems and applications programs.

1.3.2 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.

1.4 References

1.4.1 CICA Handbook ("CICA HB") Section 3060 – Capital Assets

1.4.2 CICA HB Section 3450 – Research and Development Costs

1.4.3 OEB Accounting Procedures Handbook for Electric Distribution Utilities ("APHandbook")

1.5 Accounting Policy

1.5.1 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.

Accordingly, expenditures related to the acquisition or betterment of an asset, where future benefits are reasonably assured, should be capitalized as an asset and all other expenditures should be expensed in the accounting period incurred.

1.5.2 General concepts

i. Computer software, developed or obtained for internal use, where future benefits are reasonably assured, is an intangible capital asset. (CICA HB)

ii. Capital assets are expenditures for which the future benefits to the company extend over one or more accounting periods / years.

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.

1.5.3 System software

System software should be capitalized since it is an integral component to the operation of the hardware.

1.5.4 Application software

Application software related to specific software systems should be capitalized, e.g. Customer Information System, Ellipse, LDC Settlement, EARMS, GEAR, etc.

1.5.5 PC Desktop Software

Personal computer desktop software, both system and application software, should be expensed in the accounting period incurred due to its relatively immaterial nature as well as for practical purposes. Some examples would include Microsoft Project 98, Microsoft Windows, Microsoft Office, etc. The rationale for this decision is based upon weighing the costs of administering the asset class and the benefits that the enhanced cost tracking provides from an internal control perspective.

1.5.6 Betterments (capital) versus expense (operating)

Expenditures that meet the definition of a betterment should be capitalized.

i. Betterments costs are those incurred to "enhance" the service potential of "existing" computer software. Service potential may be enhanced when there is an increase in the previous assessed physical 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 a capital 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.

1.5.7 Software costs to be capitalized

Cost

Cost is the amount of consideration given up to acquire, construct, develop, or better a capital asset. It includes all cost directly attributable to the acquisition, construction, development, or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

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 capitalized are:

i. Program development costs

ii. Coding

iii. Testing

iv. Production of training and system documentation

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 a tangible capital 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
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.

1.6 Amortization

Consistent with the CICA HB, the OEB 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.

1.7 Materiality and minimum threshold dollar amounts for capitalization

For practical purposes, once an expenditure has been determined as capital in nature, only those expenditures which 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.

1.8 OEB Uniform System of Accounts

The APHandbook defines computer software 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

1.9 Capital assets definition (CICA HB)

Computer software is a capital asset. Capital assets are defined as identifiable assets comprising property, plant and equipment and intangible properties that meet the following criteria:

i. Are held for use in the production or supply of goods and services, for rental to others, for administrative purposes, or for the development, construction, maintenance or repair of other capital assets;
ii. Have been acquired, constructed or developed with the

intention of being used on a continuing basis; and

iii. Are not intended for sale in the ordinary course of business.

APPENDIX 4-B: DISTRIBUTION PLANT CAPITAL

Rebuilds and Conversions

Total Cost $ 49,704,000

Project Description

1. These projects involve the replacement of deteriorated or damaged distribution structures and electrical equipment.
2. Rebuild projects can involve either the complete rebuilding of deteriorated lines or the selective replacement of line components. Rebuild decisions are based on the need to maintain the integrity, safety and reliability of the system.
3. Rebuild projects may be done at the same voltage level or, in the case of 4.16 kV plant needing rebuilding, the plant may be converted to 13.8 kV or to 27.6 kV.
4. The work planned for 2006 includes approximately 80 rebuild projects at the same voltage level and approximately 20 voltage conversion projects.

Justification

5. THESL maintains its distribution plant according to a thorough assessment that uses a Reliability Centred Maintenance methodology. 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.

6. 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 area. Identified projects are scored against a pre-established set of criteria in categories including reliability, risk mitigation, and financial impact.

7. Projects in this pool, for the most part, benefit customer reliability. After a rebuild, distribution plant assets that are designed to current standards are more maintainable and reduce safety risks to the general public and staff. In the case of rebuilds involving voltage conversion, low voltage substation equipment is decommissioned and replaced with higher energy capacity equipment. The higher voltage distribution equipment has lower energy losses leading to cost savings. This results in a financial benefit to customers.

Expenditures

8. Table 1 below summarizes the projected 2005 and 2006 rebuilds and conversions expenditures

Table 1 – Projected 2005 and 2006 Rebuilds and Conversions Expenditures

	2005 ($ 000)	2006 ($ 000)
Rebuild to 13.8 kV from lower voltage	9,204	7,106
Rebuild to 27.6 kV from lower voltage	17,545	9,585
Rebuilds at same voltage	26,429	33,014
Total	**53,178**	**49,704**

9. Of the work planned for 2006, individual projects that equal or exceed $500,000 are listed in Table 2. These figures are also reflected in Table 1 above.

Table 2 – 2006 Individual Rebuilds and Conversions Projects Equalling or Exceeding $500,000

Project Number	Description	Project Cost ($ 000)
7911	CS 2006 CAPITAL REPLACEMENT U/G EQUIP	7,283
7853	CS 2006 CAPITAL REPLACEMENT O/H EQUIP	5,809
6987	W06207 Remte Sw. Inst. 27.6 kV-CMO Impr. IPHL RC3160- install sw at new locations	2,231
7125	DC_W06170 Design for 2007 Const.Project [1]	1,918
7124	DC_E06152 Design for 2007 Const.Project [1]	1,648
7329	E5144 Brimley NA502M30 UG feed_NAH9M25	1,395
7045	W06085, King St West VC B-9-PQ OH&UG Install & Removal	1,263
6984	W06206 NY Remote Switch Repl. phase 1 IPHL RC 3160	1,161
6854	E5308 BROADVIEW PRETORIA B1HW OH VC	1,119

	RLBT CONVERSION 4kV TO 27kV	
6800	E6188 Doris Ave Ext M27 to 31 UG Rehab	1,119
6957	E06199 NY Remote Switch Replacement IPHL	1,108
8012	ST CLAIR DU-4KV OH VC PHASE- I (OVERHEAD) - IPHL	1,026
7535	W5274 Bloor St. W. 27.6KV U/G VC Montgomery & Prince Edward	1,005
8014	DUFFERIN TS UG VC FOR ST CLAIR PHASE - II (UNDERGROUND) - IPHL	986
6885	E06192 Remote SW Inst 27.6kv-CMO Impr IPHL-Revision for 9 switches only	981
7777	W06074 Queen St West VC B-6-PQ OH & UG	941
7538	W6020 Bloor-West Mall VDF2F4 UG VC	923
4064	E06008 Mossbrook Cable repl, NA502M28 Replacement Mossbrook and Jordanroch	887
7179	DC_W06031 Civil Infrastructure W-CC roof 2006	875
7314	E5291 Pharmacy-Victoria Park WAF2, Ph.3	821
7174	DC_E06030 Civil Infrastructure E-CC roof 2006	817
7283	E6091 Carlton Sherbourne B-5-SE OH VC Rebuild	759
7082	E06071Parkview Hills Ph1	750
5970	WBS4/LU Wildcat W05226	741
6720	E06077Parkview Hills Ph2 JF3OH VC sfty	740
7990	E-6050, SOUTHWOOD A-20,21,30,31-MN UG EN	722
6800	E6188 Doris Ave Ext M27 to 31 UG Rehab	721
7200	W4247 RATHBURN M.S. V.C. PHASE 1	654
7406	N06098 Danforth Woodycrest Network conversion from 120/240 to 120/208V	601
4827	E5265 Pharmacy / Craigton WAF2 VC, Ph. 4 IPHL	567
7960	N06252 St Clair_Vgn A4-52-B UG VC RC3360	563
5137	E5243 Anaconda/Chestnut 43M26 OH VC	505

[1] THESL collects design time for future year projects in a single capital project for budget purposes. The time is then divided to projects retroactively after design.

10. The project budget estimate is based on detailed engineering estimates of the individual project components.
11. Some capital projects in the rebuild and conversion project pool are multi-year projects. Generally, rebuild and conversion projects are planned within a three-year time horizon.

New Feeders and Upgrades

Total Cost $35,428,000

Project Description

12. These projects consist of the construction of new feeders, equipment or conductor upgrades on existing feeders (both overhead and underground), and the installation of sections of feeders to accommodate peak demand growth.

13. The work planned for 2006 consists of approximately 40 projects.

Justification

14. The need to increase the capacity of the distribution system arises primarily due to load growth caused by 1) new customer connections and service upgrades, 2) incremental growth in the demand of existing customers, and may include replacement of deteriorated equipment.

15. Projects in this pool represent an increase in distribution capacity that benefits many customers. They are not strictly for the benefit of single customers.

16. New feeder and upgrade projects permit customer needs to be met in a reliable way. Available capacity is used as much as possible by periodically reconfiguring existing circuits and equipment. Only once these options have been exhausted, is capacity increased. Capacity increases permit THESL to operate equipment within optimal rating parameters and to operate the distribution system according to accepted

industry practices. This increases service reliability and allows unimpeded customer growth.

Expenditures

17. New feeders and upgrades expenditures for 2005 and 2006 are summarized in Table 3 below.

Table 3 – Projected 2005 and 2006 New Feeders and Upgrades Expenditures

	2005 ($ 000)	2006 ($ 000)
New feeders	-	2,127
Upgrades[1]	20,795	33,301
Total	**20,795**	**35,428**

[1]Projects are often classified as upgrades when they involve a rebuild or conversion because additional capacity is built in. These figures should be examined together with those of Rebuilds.

18. Of the work planned for 2006, projects that equal or exceed $500,000 are listed in Table 4. These figures are also reflected in Table 3 above.

Table 4 – 2006 Individual New Feeders and Upgrades Projects Equalling or Exceeding $500,000

Project Number	Project Description	Project Cost ($ 000)
8109	System Infras Civil & Cable Enhanc 2006	2,677
7242	DC - Equipment Enhancement - Lock Repl.	2,113
7541	W06006 WR - CE LOAD TRANSFER-Electrical	2,045
7192	DC_E06153Syst Enhancement:UG cable	1,112

	rehab	
7193	DC_W06169Syst Enhancement:UG cable rehab	1,112
7602	DC_Grounding Provisions 2006 Const East	966
7606	DC_Grounding Provisions 2006 Const West	966
6363	W06122Civil Adelaide St W IPHL	856
7837	E6076 Load Transfer A-1-2A to A-1-2-GD	830
7166	E06100 Garnier 80M21 U/G Cable Replace	797
7181	DC_W06227 Syst Enhancement-OH rehab 2006	774
7009	E06052 DUNDAS/HASTING PH1 OH VC	764
7920	E6072 Load Transfer A-7-8A to A-1-2-GD	731
7176	DC_E06226 Syst Enhancement-OH rehab 2006	711
7995	W06238 St Clair &Bathurst UG Conv, Civil IPHL	691
7191	E06066 DUNDAS/HASTING PH2 OH VC	646
7477	Grounding Provisions for 2006 inspection Inspection, review & package preparation	611
7061	N06165 Repl ATS with Stand Alone Protect	579
7039	N06028 CRESCENT TOWN PH4Repl of Equip SF6 SW &3-SINGLE PH TX CONV	574
7332	E06097 HUNTSMILL NA502M28 ELECTRICAL	569
7350	W06118 St. Clair OH Rearr/Bathurst-Gunns IPHL	555
7365	W6018 St Marks Humberview 11M5 OH	519
6519	W06172Civil Const for B & H Tie Feeders IPHL	513
7287	E06211 Doris Av UG Ducts & CC Upgrade	510

19. Some capital projects in the new feeders and upgrade pool are multi-year projects. Generally, new feeders and upgrades are planned within a five-year horizon.

Services

Total Cost $42,588,000

Project Description

20. Projects in this pool 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.

21. The work planned for 2006 includes 9,600 residential services, 390 commercial services, 70 power class services and 181 subdivisions, affecting a total of approximately 10,000 customers.

Justification

22. The new component of this project is justified based on THESL's obligation to serve and to address customers' new service requirements. The replacement component is justified on the basis of the obligation to meet changing customer needs.

Expenditures

23. Table 5 provides below summarizes projected 2005 and 2006 Services expenditures.

Table 5 – Projected 2005 and 2006 Services Expenditures

	2005 ($ 000)	2006 ($ 000)
Services—Residential	5,760	8,520
Services—Commercial	31,656	25,487
Services—Power Class	3,984	1,451
Subdivisions—Residential	-	7,130
Subdivisions—Commercial	-	-
Total	**41,401**	**42,588**

24. The cost of new services collected from customers in the form of capital contributions is estimated at $15,500,000 for 2005 and $22,000,000 for 2006.

25. Of the work planned for 2006, individual projects that equal or exceed $500,000 are listed below in Table 6. These figures are also reflected in Table 5.

Table 6 – 2006 Individual Services Projects Equalling or Exceeding $500,000

Project Number	Description	Project Cost ($ 000)
7633	University Of Toronto Varsity	2,589
7760	CFDC-East 2006 Cut Repair Restorations Costs paid 2006 for prior years'	2,319
7813	Subd'n-submersible TX 4 tapbx-U/G crew Event 21B	2,190
7637	U/G SECONDARY SERVICE BY CONTRACTOR Event 3BSec Ser. Sub. C.C.R'	1,392
7778	CTC SUBD'N - 2006 DRAFT PLAN CFDC-E for 2006 Budget	1,786
7653	UPGRADE O/H SECONDARY SERVICE BY O/H Event 4A O/H - 3	1,785

	Person Crew 06/23	
7730	U/G LINE EXT BY U/G CREWS CFDC-W Event 20B X20	1,192
7652	UPGRADE O/H SECONDARY SERVICE BY O/H Event 4A O/H - 3 Person Crew 06/23	1,372
7638	U/G SECONDARY SERVICE BY CONTRACTOR Event 3BSec Ser. Sub. C.C.R'	696
7526	Modular Vault 1000kVA, 347/600V CFDC-E Event 16 06/21;	1,076
7524	Customer Owned Substation CFDC-W Event 15 06/21;	1,024
7812	Subd'n-minipad & 4 tapboxes by U/G crews Event 21A	1,036
7809	Subd'n-minipad & 4 tapboxes by O/H crews Event 14A	873
7631	U/G SECONDARY SERVICE BY O/H CREWS Event 2 O/H - 3 PERSON CREW 06/23	914
7531	Modular Vault 1000kVA, 347/600V CFDC-W Event 16 X4 06/21;	863
7623	Padmount (Xfmr) Radial 1500 kVA Event 9A6 CCR'	836
7620	Padmount (Xfmr) Radial 1500 kVA Event 9A6 CCR'	743
7657	UPGRADE U/G SEC. SER (RESIDENTIAL) WEST Event 5 <750V-O/H & U/G CCR'	707
7729	U/G LINE EXT BY U/G CREWS CFDC-E Event 20B X10	598
7497	Padmount (Xfmr) Radial 500 kVA Event 9A3 CCR'	605
7485	Padmount (Xfmr) Radial 300 kVA Event 9A2	500
7762	CFDC-West 2006 Cut Repair Restorations Costs paid 2006 for prior years' work	512

26. The estimated requirements for new services in 2006 are based on the known customer requests as well as historical data on connections of similar services.

27. THESL performs an economic evaluation (prepared in accordance with prescribed valuation methodologies) of service projects that require new facilities to be built on the distribution system or those that require an increase in capacity of the distribution system. The economic evaluation is used to 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. If there is a shortfall between the present value of the projected costs and revenues, the customer pays the difference as capital contribution in accordance with the Distribution System Code. In addition, all customers pay for the cost of installing connection assets, less a standard connection allowance.

Stations

Total Cost $9,445,000

Project Description

28. Station projects involve switching and other equipment associated with the receiving and distribution of electricity at terminal stations as well as the transformation, switching and other equipment required for stepping down distribution voltages to lower distribution voltages.

29. Typically, all equipment within the confines of the station area that is used from the high voltage feeder through to the low voltage connection outside the station is included in these types of projects.

30. Approximately 30 projects are planned for 2006.

Justification

31. Stations are the starting point of the distribution system and provide switching points to enable reconfigurations of the distribution system to respond to changing system conditions and outages. Station outages due to equipment failure typically impact large numbers of customers and have a considerable impact on service reliability to those customers. Stations generally have higher reliability performance than most other parts of the distribution system. Station project work is required to mitigate low probability / high reliability impact risks to customers.

Expenditures

32. Table 7 below summarizes projected 2005 and 2006 station expenditures.

Table 7 – Projected 2005 and 2006 Stations Expenditures

	2005 ($ 000)	2006 ($ 000)
Electrical	10,982	7,603
Buildings	1,617	1,842
Total	**12,599**	**9,445**

33. Of the work planned for 2006, projects equalling or exceeding $500,000 are listed below in Table 8. These figures are also reflected in Table 7 above.

Table 8 – 2006 Individual Stations Projects Equalling or Exceeding $500,000

Project Number	Description	Project Cost ($ 000)
7974	Transformer Station Metering RC 4100	1,264
7403	Station Design for 2007 Projects1	1,052
7859	TS Meter Instrument Transformer Upgrades	729
8166	Paving, Door Replacement Roofing Program	575
7547	VARIOUS STNS - REPLACE TWO KSO CB 2006	547

[1] THESL will track design time for future year projects into a single capital project for budgeting purposes. The total time will then be divided into projects retroactively after the design phase.

34. The 2006 estimate is based on detailed engineering estimates of the individual project components.

35. THESL receives almost all of its electricity from facilities that are owned in whole or in part by Hydro One Networks Inc. ("HONI"). As expansions are required, capital contributions are paid to HONI in accordance with the Transmission System Code. Table 9 summarizes the historical and projected capital contributions paid to HONI.

Table 9 – 2002 to 2006 Capital Contributions Paid to HONI.

Year	2002 Actual ($ 000)	2003 Actual ($ 000)	2004 Actual ($ 000)	2005 Projected ($ 000)	2006+ Projected ($ 000)
Cecil TS	-	-	2,223		-
Low voltage line purchase	-	-	1,605		-
Wiltshire TS 1	-	-	-		500
Manby TS 1	-	-	-	-	1,200

[1] Timing uncertain, contributions may be beyond 2006

Relocations

Total Cost $4,371,000

Project Description

36. Due to the congested nature of many of the City of Toronto's thoroughfares, distribution plant is located in close proximity to other utility plant as well as to City of Toronto infrastructure. In relocation projects, THESL is requested to relocate its distribution plant to accommodate other utility work or City of Toronto work. Road widening and closures, bridge re-builds, requests from other utilities, and customer requests for plant relocation, either temporary or permanent are common reasons to re-locate plant.

37. THESL and the City of Toronto cooperate to coordinate work to avoid unnecessary costs and re-work.

Justification

38. Relocation projects are performed primarily because third parties need plant relocated in order to do their work. Projects in this pool benefit customers by increasing reliability as permanent relocations that are built to current standards replace plant that is usually older and less reliable.

Expenditures

39. Table 10 below summarizes 2005 and 2006 projected relocations expenditures.

Table 10 – Projected 2005 and 2006 Relocations Expenditures

	2005 ($ 000)	2006 ($ 000)
Relocation Total	**4,385**	**4,371**

40. Of the work planned for 2006, individual projects equalling or exceeding $500,000 are listed below in Table 11.

Table 11 – 2006 Individual Relocations Projects Equalling or Exceeding $500,000

Project Number	Description	Project Cost ($ 000)
7471	W6073 King St UG Route of VC B-5-6-9-PQ	842
8044	E-5304, LEASIDE BRIDGE REHAB - PHASE 2	816
7205	W6011 LOAD TRANSFER A3-4A TO A5-6CE	590

41. The 2006 estimate is based on detailed engineering estimates of the individual project components.

APPENDIX 4-C: GENERAL PLANT CAPITAL

Computer Equipment, Hardware and Software

Geo Electric Mapping Records ("GEAR") Implementation

Total Cost: $5,452,000

Project Description

1. The GEAR Project involves the implementation of a single-platform Geographic Information System ("GIS") by replacing the existing legacy GIS systems inherited from the pre-amalgamated utilities and completing the migration of data to maintain system records, produce maps and on-line views, and analyze the distribution system.
2. The GEAR Implementation Project was envisioned as a 5-year project that commenced in 2003.
3. The project also includes an interface with our enterprise resource management system, Ellipse.

Justification

4. The GIS system provides records of the electrical distribution system. GIS records are used for planning, design, and construction of supply to new customers or upgrades to existing plant. These records are also used for plant locates prior to third parties performing work in the vicinity of our distribution plant.
5. THESL inherited six different GIS systems from the former utilities, that require on-going separate support and maintenance.

6. Some of the existing platforms are no longer supported by their vendors, thus hindering system enhancements.
7. The single platform will allow symbols harmonization resulting in better clarity to users involved in planning, design and construction. It will also provide a single interface with existing systems such as Ellipse, and the Customer Information System (Banner), THESL's Distribution Management System, and THESL's future Outage Management System.
8. A single solution will:
    - Improve crew safety through accurate data in Distribution Management System;
    - Improve outage response time and customer service quality by having accurate data flow to Outage Management System;
    - Improve asset management analysis and decisions by the availability of uniform distribution system information; and
    - Reduce damage by third parties performing work in the vicinity of THESL's plant, resulting in improved distribution plant records.

Expenditures

9. Table 1 provides a breakdown of the proposed expenditures for 2006 and projected expenditures for 2005.

Table 1 Projected 2005 and 2006 GEAR Expenditures

	2005 ($ 000)	2006 ($ 000)
GEAR implementation	1,405	4,738
Ellipse/GEAR interface	-	714
Total	**1,405**	**5,452**

10. This undertaking is a multi-year project with a technology component going into 2007.

Outage Management and Customer Service Delivery

Total Cost: $3,660,000

Project Description

11. The Outage Management and Customer Service Delivery Project is a combination of process improvements and information system installations designed to improve outage response, service delivery and communication with our customers.

Justification

12. THESL performs over 15,000 customer requested service calls each month. Currently, THESL often cannot give customers a commitment about when service will be provided, nor accurate information about the current status of services that have been previously requested. Much of the internal communication about service orders consists of faxed information, verbal instructions via radio, and hand-written completion reports. Industry surveys have concluded that the top two inquiries from a customer calling to report a power interruption wants to have answered are: 1) Does the utility know about the outage? and 2) How long will the power be off?

13. With the present processes and information systems, these questions usually cannot be answered when customers call. This project is expected to:

    a. Improve customer service quality by making and keeping commitments on when a service will be delivered;

b. Improve customer satisfaction by providing accurate information about the status of a service request or trouble call;
c. Increase service reliability by reducing SAIDI ("System Average Interruption Duration Index");
d. Increase effectiveness of response to multiple power outages that occur during storms;
e. Reduce operating costs by better monitoring and optimizing the distribution of customer service work assignments;
f. Leverage existing information system capabilities to better manage outages and short duration customer work requests; and
g. Improve asset management analysis and decisions by improving the availability of information on customer impacts of equipment failures.

Expenditures

14. Table 2 below summarizes 2005 and 2006 projected computer hardware and software equipment expenditures.

Table 2 Projected 2005 and 2006 Computer Hardware and Software Equipment Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	-	350
Software	-	1,160
Consultant Services	170	1,600
Labour	565	550
Total	735	3,660

15. This project is a multi-year project with a technology component going into 2007 and data and sustainment activities reaching into 2007 and 2008.

Distribution Management System Installation for Control Room Consolidation Project

Total Cost $556,250

Project Description

16. When the six utilities amalgamated in 1998, there were six distinct operations control rooms responsible for the respective distribution systems. The six utility control operations were moved to the 5800 Yonge St. facility in 2002 and 2003, complete with all of their former operating platforms and practices. The new control room was structured to continue to provide service to the field operations and maintain relationships with outside customers and regulating bodies.

17. This project is expected to:
    a. Consolidate the system modeling tool utilized by Power System Controllers to establish a common control platform for the six former district control areas, and
    b. Standardize work practices in the control room to support crews working across former utility borders so technical language and practices are harmonized.

Justification

18. This project is expected to provide the following benefits:
    a. Facilitate cross training of Power System Controllers on all former districts to provide greater flexibility for staffing;

b. Standardize the control room, support harmonization of work practices in the field, and support customer care activities to improve the flow of information to update Customers on outage information; and

c. Consolidate operating practices in the Toronto Hydro Control Room that will further standardize the technical operating language across all former control districts and increase the level of safety by further harmonizing the application of the Toronto Hydro Work Protection Code.

Expenditures

19. Table 3 summarizes the projected 2005 and 2006 Distribution Management System Installation for Control Room Consolidation Project expenditures.

Table 3 Projected 2005 and 2006 Distribution Management System Installation for Control Room Consolidation Project Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	460	-
Software	100	-
Consultant Services	30	431
Labour	15	125
Total	**605**	**556**

Intel Server Technology Upgrade

Total Cost: $706,000

Project Description

20. This is a project to replace a portion of the existing computer servers. Departmental application services, file management and e-mail are hosted on a series of smaller computer servers based on Intel microprocessors.

Justification

21. It is common industry practice to replace Intel computer servers after 4-5 years of operation. An increased incidence of hardware failure, reduced technical support and the higher performance requirements of current generation operating systems and applications drive this lifecycle. Migrating older units to lower performance roles extends the asset life of servers and this has been done to the extent possible and practical. Ultimately, technical obsolescence makes the continued use of these older servers a liability to business operations. As a continuous business process of technology upgrade, servers are acquired in batch purchases, following a uniform standard and competitive process.

Expenditures

22. Table 4 below summarizes the projected 2005 and 2006 Intel Server Technology Upgrade expenditures.

Table 4 Projected 2005 and 2006 Intel Server Technology UpgradeExpenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	325	375
Software	-	306
Labour	25	25
Total	**350**	**706**

Telephony Infrastructure Upgrade

Total Cost: $650,000

Project Description

23. This project continues the telephony system renewal on a multi-year balanced spend schedule, beginning in 2005 and ending in 2007.

Justification

24. THESL operates an internal telephone system to service its customer care centre, its distribution system operations control centre and for general business operations. The system supplier has announced that support and fixes for key elements of the current phone system will cease in 2007. This obsolescence follows the usual industry lifecycle for such equipment.

25. Due to the proprietary nature of phone systems, the replacement of individual components cannot be done independently of the overall product family. As such, the retirement and replacement of the overall system is accomplished by replacing the core telephony servers and systems first, thereby allowing a controlled migration of the peripheral components to a new technical standard.

26. Key business requirements being addressed through this replacement include the core telephony infrastructure used by customers reaching our customer care operations during both normal operations and power outage situations. This investment supports the continued effort to

sustain and improve on key performance indicators directly affecting customers as mandated by the OEB.

Expenditures

27. Table 5 below summarizes the projected 2005 and 2006 Telephony Infrastructure Upgrade expenditures.

Table 5 Projected 2005 and 2006 Telephony Infrastructure Upgrade Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	345	400
Software	-	100
Labour	65	150
Total	**410**	**650**

Smart Meter Related Systems

Total Cost: $3,000,000

Project Description

28. This project encompasses information system changes that are required to support the implementation of Smart Meters. This project will be phased to meet the requirement for Smart Meter billing by the specified date, currently set at April 2006.

29. This project encompasses steps that may be necessitated to prepare existing systems, or as time allows, adopt alternate approaches that would provide longer-term benefit.

Justification

30. THESL actively promotes customer conservation and demand management initiatives. Time of use rates re-introduce a more granular means of costing electricity use that, in turn, more closely reflects periods of higher cost production. The introduction of smart meters and the associated Regulated Price Plan rates for use with such meters introduces new requirements in the areas of billing, account management and the presentation of information to customers.

Expenditures

31. Table 6 below summarizes projected 2006 Smart Meter Related Systems expenditures.

Table 6 Projected 2006 Smart Meter Related Systems Expenditures

	2006 ($ 000)
Software	3,000
Total	**3,000**

SCADA Upgrade and Consolidation

Total Cost: $ 2,307,000

Project Description

32. THESL has consolidated the control centre operations from the original six constituent utilities into a single site with two supporting SCADA systems. All but one geographic region has been converted to a primary system of monitoring and controlling distribution system devices.

33. This project entails a version upgrade of the application, the migration of this application to a different hardware platform and the final phase of consolidation of the geographic regions of THESL into a single monitoring and control system.

Justification

34. During normal business operations SCADA enables the remote operation of key breakers and feeder devices to facilitate distribution system reconfiguration for the purposes of maintenance and construction. During outage situations the same monitoring and control features shorten the diagnosis and resolution of problems, thereby reducing the duration of outages to most customers (when the outage is caused by distribution system equipment failure). The system also permits rapid response to supply emergencies to enable critical loads on the distribution system to receive priority.

35. The manufacturer of the SCADA computer system hardware has announced the end of life for this product line, forcing a controlled migration for all users of this product to an alternate hardware platform.

Expenditures

36. Table 7 below summarizes the projected 2005 and 2006 SCADA Upgrade and Consolidation expenditures.

Table 7 Projected 2005 and 2006 SCADA Upgrade and Consolidation Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	-	300
Software	-	650
Consultant Services	-	1,130
Labour	-	227
Total	**-**	**2,307**

Ellipse Upgrade

Total Cost: $ 3,690,000

Project Description

37. Ellipse is an integrated Enterprise Resource Planning ("ERP") system from Mincom, the system vendor. The Ellipse system was implemented at THESL in March 2002. In addition to its asset management and work management capability, Ellipse provides support in the supply chain, finance and human resources areas. Ellipse is a key enabler for the planning, execution and tracking of THESL's capital and maintenance programs.

38. This project involves a major version upgrade of Ellipse.

39. In addition to being a major technological upgrade, the project presents an opportunity to streamline some of the current work practices with improvements to business processes and technology support for those processes.

Justification

40. Vendors of ERP software typically release major upgrades to their products every two years, and support only the current and previous versions. Industry best practice and prudent systems management dictate that THESL should keep current with supported software versions and upgrade at least every four to five years. As the current version will no longer be supported after May 2007, THESL needs to

initiate the project in 2005 and begin preparatory work for implementation in 2006.

Expenditures

41. Table 8 below summarizes the projected 2005 and 2006 Ellipse Upgrade expenditures.

Table 8 Projected 2005 and 2006 Ellipse Upgrade Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	200	-
Software	1,134	-
Consultant Services	530	1,466
Labour	603	2,224
Total	**2,467**	**3,690**

General Technology Upgrade

Total Cost: $2,026,000

Project Description

42. There are ten different general technology upgrade projects. Three projects involving desktop PCs and laptops, engineering workstations and network printers fall into the category of Upgrade of End User Desktop Services. Two projects fall into the category of Upgrade and Consolidation of Servers. The other five projects are different enough to not be categorized together.

Justification

43. It is a common industry practice to keep both the software and hardware environments up to date. Increased incidence of hardware failure; reduced, or withdrawal of, technical support; new technical standards and higher performance requirements of current operating systems and applications drive this lifecycle. The upgrade of aging servers and consolidation of multiple servers to a more manageable volume provide cost effective migration of workload with higher performance efficiencies and lower maintenance costs. The upgrade of selected network infrastructure and Internet connections is expected to improve network reliability, increase bandwidth and provide the necessary platform to develop more cost effective customer service applications and reduce interface costs to existing applications.

Expenditures

44. Table 9 below summarizes the projected 2005 and 2006 General Technology Upgrade expenditures.

Table 9 Projected 2005 and 2006 General Technology Upgrade Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	949	1370
Software	279	302
Consultant Services	-	218
Labour	108	136
Total	**1,336**	**2,026**

General System Development

Total Cost: $ 726,000

Project Description

45. There are six general system development projects.

46. In addition to major implementation projects such as the Outage Management or GIS projects, THESL regularly undertakes a number of smaller development activities to meet regulatory / OEB requirements, improve safety and reliability, and enhance customer services. Most of these activities involve enhancements to existing applications. THESL business users, IT system delivery staff and IT infrastructure technical staff usually carry out development projects.

Justification

47. The largest project ($191,000) involves Customer Care applications and is set up to address existing regulatory / OEB requirements. A smaller project is designed to enhance customer services using computer telephony integration.

48. Two projects involving IT infrastructure technical staff provide general technical support to all system development activities. These projects provide technical services in database administration, Web services, tools and methods, and other IT infrastructure services.

49. One project in the GIS application area supports transformer load management to improve reliability.

50. Rubber gloves are important personal protective equipment that help ensure the safety of THESL field personnel. One project in the glove test lab is designed to improve the reliability and efficiency of rubber glove testing.

Expenditures

51. Table 10 below summarizes the projected 2005 and 2006 General System Development expenditures.

Table 10 Projected 2005 and 2006 General System Development Expenditures

	2005 ($ 000)	2006 ($ 000)
Hardware	20	40
Software	70	83
Consultant Services	987	55
Labour	1,442	548
Total	**2,519**	**726**

Fleet and Equipment

Total Cost: $6,155,000

Project Description

52. This project provides for the replacement and modification of major tools, equipment and vehicles managed by the Fleet Department to support the construction and maintenance of the electricity distribution system.

Justification

53. This project is justified based on the need to maintain major equipment functionality and provide safe, reliable tools and equipment.

54. The strategic vehicle replacement program will:

    - Replace vehicles in an even fashion avoiding sudden increases in capital acquisitions, and
    - Replace vehicles before they become costly to repair and uneconomic to operate.

55. The vehicle replacement program is based on annual condition surveys and life cycle planning. Surveys and checklists to detail problems, deficient conditions and maintenance needs are maintained as part of the vehicle profile.

56. New vehicles and equipment support productivity through innovation, improve field crew response time, reduce costs from fuel savings, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

57. Tool and Equipment replacement supports a safe working environment, which reduces costs from lost time accidents caused by equipment failure.

Projected Expenditures

58. Table 11 below summarizes the projected 2006 Fleet and Equipment expenditures.

Table 11 Projected 2005 and 2006 Fleet and Equipment Expenditures

	2005 ($ 000)	2006 ($ 000)
Capital Vehicles	3,840	5,405
Major Tools & Equipment	403	750
Total	**4,243**	**6,155**

Real Estate and Facilities Services

Total Cost: $3,951,000

Project Description

59. This project provides for the replacement and modification of buildings, building systems and furnishings.

Justification

60. This project is justified based on the need to maintain building functionality and provide safe, functional and supportive work environments. Funds are used 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/or in-house technical staff. Complementing the comprehensive condition assessments, which are conducted on a 5-year cycle, are annual condition surveys by maintenance and operations staff. The surveys are checklists to detail problems, deficient conditions, and maintenance needs at sites, buildings, and other structures, including, 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.

61. Office equipment refurbishment and ergonomic enhancement reduce occupational injuries. Worn or broken office support equipment reduces the ability to be productive when responding to customer needs.

62. Refurbishment of our operational centres sustains the health and safety of our staff and supports business unit efficiency.

Projected Expenditures

63. Table 12 below summarizes the projected 2006 Real Estate and Facilities Services expenditures.

Table 12 Projected 2005 and 2006 Real Estate and Facilities Services Expenditures

	2005 ($ 000)	2006 ($ 000)
Building & Systems Improvements	2,374	3,621
Furniture & Equipment	80	330
Total	**2,454**	**3,951**

APPENDIX 4-D: CAPITALIZATION POLICY

Capitalization Policy: Date: 6/16/00
Capital Assets - Property, Plant & Equipment & Intangible Properties

Purpose:
This document describes the accounting policies and recommended accounting treatment for the appropriate classification of company expenditures. Whether expenditures should be capitalized on the balance sheet (capital assets) or expensed to operations in the period incurred (expense).

Background:
Accurate recognition of our expenditures as either capital assets or expenses is necessary to: 1) meet the financial reporting requirements of our regulator, the Ontario Energy Board (OEB), Accounting Procedures Handbook for Electric Distribution Utilities (APHandbook); 2) to provide accurate financial reporting to management and our shareholder; and 3) to prepare meaningful annual budgets.

Authority:
This policy is in accordance with the OEB "Accounting Procedures Handbook For Electric Distribution Utilities"; and the CICA Handbook, Section 3061 - Capital Assets.
The OEB Accounting Procedures Handbook (APHandbook) prescribes that "the accounting concepts for the measurement, presentation and disclosure of capital assets are based on CICA Handbook Section 3060 - Capital Assets."

Accounting Policy:

1) **Governing Principle**
The purpose for "capitalizing" expenditures as capital assets is to provide for an equitable allocation of costs among existing and future customers. As assets are expect to provide "future economic 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 / depreciation.
Accordingly, expenditures relating to the acquisition, construction or betterment of an asset, should be capitalized as an asset, and all other expenditures should be expensed in the accounting period incurred.

Capitalization Policy: Date: 6/16/00
Capital Assets - Property, Plant & Equipment & Intangible Properties

2) **General:**

i) "Capital assets" are expenditures for which the future benefits to the company extend over one or more accounting periods / years.
ii) "Expenses" (frequently referred to as operating expenses or maintenance expenses), are expenditures where the benefits do not extend beyond the current accounting period / year.
iii) Future benefit involves a capacity of the asset to contribute directly or indirectly to future net cash flows.

3) **New Capital Assets:**

New capital assets may be:

* purchased in completed state;
* constructed by the company; or
* result from capital lease agreements.

Capital assets are also created from costs incurred for "Betterments", as discussed below.

4) **Capital Assets Definition:**

Capital assets comprise "property, plant and equipment" and "intangible properties" that meet all of the following criteria:

i) are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other capital assets;
ii) have been acquired, constructed or developed with the intention of being used on a continuing basis; and
iii) are not intended for sale in the ordinary course of business.

Property, Plant and Equipment:

These are capital assets that are tangible, comprised primarily of "distribution plant" and "general plant" as defined in the APHandbook uniform system of accounts. Distribution plant and general plant are dstribution assets used to distribute electricity, and include any system, structures, equipment or other asset used for that purpose.

Intangible properties:

These are capital assets that lack physical substance. The value is represented by business rights which confer some operating, financial or income producing advantages to the company. e.g. land rights, computer software, licences, etc. (See separate accounting policy for computer software).

5) **Asset Recognition - Capital versus Expense**
In order to recognize capitals asset (i.e. capitalizing the related costs on the balance sheet versus "expensing" these costs to operations), an expenditure should meet the definition for capital assets provided.

Toronto Hydro specific examples for both capital assets and expenses:
Toronto Hydro has a comprehensive list of examples for both capital assets and expenses. These examples are guidelines only, and in limited cases may be subject to interpretation when reviewing the expenditure background information.

6) **Betterments (capital) versus Expense (operating)**
Expenditures that meet the definition of a betterment should be capitalized, while expenditu that meet the definition of an expense should be expensed.

Discussion for further clarification:

i) Betterments are costs incurred to "enhance" the service potential of an "existing" capital asset. The service potential of an existing capital asset may be "enhanced" when there is an increase in the previous assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. The identification of a betterment is a matter of professional judgment.

ii) Expenses are defined as the costs incurred in the "maintenance" of the service potential of a capital asset. Expenses are costs incurred more or less on a continuous basis to keep the capital asset in normal operating condition, but do not add materially to the use value of the asset, nor prolong its life appreciably.

iii) If a cost has the attributes of both an expense and a betterment, the portion considered to be

7) **Capital Asset costs:**

i) Cost is the amount of consideration given up to acquire, construct, develop, or better a capital asset and includes all costs directly attributable to the acquisition, construction, development, or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

Capitalization Policy: Date: 6/16/00
Capital Assets - Property, Plant & Equipment & Intangible Properties

ii) A capital asset should be recorded at cost, which would include the purchase price and other acquisition costs, such as:

fees; legal fees; survey costs; site preparation costs; freight charges; transportation insurance costs; duties; testing and preparation charges; and option costs when an option is exercised.

iii) **Construction costs: (APHandbook)**
The cost of construction properly included in electric plant capital accounts shall include where applicable:
* the cost of labour; materials and supplies; transportation; work done by others for the

special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes and other similar items as may be properly included in construction costs.

8) **<u>Amortization:</u>**
Consistent with the CICA Handbook, the APHandbook does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, 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 Board may review the selected amortization methods, estimated useful lives and amortization rates, as it considers necessary.

i) The amortization rates currently in use for new capital assets are provided in Appendix E. These rates are based upon past practice, as originally prescribed by our previous regulator Ontario Hydro.
ii) Amortization should be recognized in a rational and systematic manner, appropriate to the nature of the capital asset and its intended use by the company, 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.

Capitalization Policy: Date: 6/16/00
Capital Assets - Property, Plant & Equipment & Intangible Properties

9) **Materiality and Minimum threshold dollar amounts for capitalization:**
Once it has been determined that an expenditure is capital in nature, "for practical purposes", only those expenditures which exceed specified "threshold dollar amounts", should be treated as capital; and those below this amount should be treated as expenses. Toronto Hydro has a listing of the threshold dollar amounts.

10) **OEB Uniform System of Accounts (USoA):**
The APHandbook provides comprehensive definitions for: 1) capital asset accounts; 2) operating expense accounts; and 3) maintenance expense accounts. The listing of these accounts are provided in the AP Handbook.

Account definitions provide the specific OEB accounting guidelines for each capital asset and expense account. A review of the account definitions provides practical references and examples, to enable us to determine the appropriate classification of various expenditures as either a capital asset or an operating expense. OEB account definitions for "Capital assets" accounts and "Expenses" accounts are available upon request.

11) **Expenses - Clarification of Operation and Maintenance Activities:**
The OEB has determined there is value in distinguishing costs between "operating" expenses and "maintenance" expenses. We are required to report our expenses to the OEB under the uniform system of accounts (USoA) provided in the APHandbook. The distribution expenses accounts, for both operation and maintenance expenses, are available in the APHandbook. Please see the accounting policy, "Expenses - Clarification of Operating and Maintenance Expenses" for further guidance.

CHAPTER 5 – COST OF CAPITAL

5.0 Introduction

1. This Application follows and conforms to the guidelines and spreadsheet models issued by the Board for setting the cost of capital, including the allowed return on equity, the capital structure, and the debt rate.

2. In setting these financial metrics, THESL requests:

   a. The maximum allowed return on equity of 9 percent;

   b. The continued use of the deemed 65 percent debt and 35 percent equity capital structure as the basis for deriving the overall cost of capital (and revenue requirement); and

   c. A working capital allowance of $300,689,955.

   These values have been applied in the 2006 EDR Model as part of this Application.

3. The total long-term debt of THESL as at December 31, 2004 was $1,160,230,955, and was held by THC and is expected to remain unchanged through 2006.

4. THESL's weighted average Debt Rate for embedded debt is 6.70 percent, as set out in Schedule 5-1: Weighted Debt Cost.

5. Issuance costs of $298,834, representing one-years' worth of issuance costs are included in the 2006 weighted embedded cost of debt calculation. These costs were incurred in conjunction with THC's $180,000,000 loan (10-year notes) to THESL.

6. As at December 31, 2004, the actual debt-to-equity split of THESL was 62.2 percent debt and 37.8 percent equity, which is within 10 percent of the deemed 65 percent debt and 35 percent equity. Details supporting the derivation of this actual debt-to-equity split are shown in Schedule 5-2 Actual Capital Structure of THESL, as at December 31, 2004.

7. With respect to its actual capital structure, subject to obtaining approval from its Board of Directors, THESL intends to make a cash dividend payment to its parent company, THC, in the third quarter of 2005 to re-balance the company's actual capital structure back to its deemed capital structure of 65 percent debt and 35 percent equity.

5.1 Maximum Allowed Return on Equity

8. In seeking the 9 percent maximum allowed return on equity, THESL accepts, for the purpose of this Application and electricity distribution rates effective May 1, 2006, the Board's decision to use the mechanistic update for setting the maximum allowed return on equity, as set out in Chapter 5 of the DRH.

9. THESL notes, however, that the underlying approach for setting the return on equity for electricity utilities has not been comprehensively reviewed since 1998. Such a review of the overall methodology is urgently needed. For example, the methodology for determining the equity risk premium should be reviewed as soon as possible in light of the volatility experienced in Canadian equity capital markets since 1998. THESL therefore urges the Board to undertake as soon as possible and

for the derivation of rates effective May 1, 2007 the Cost of Capital Review that it has committed to perform.

10. THESL also submits that the current maximum allowed return on equity has been set at a level that is barely sufficient to allow an LDC of THESL's size to maintain a strong and cost-effective investment-grade credit rating. It is important for the Board to note that this is not just THESL's view, but also an opinion that has repeatedly been expressed by bond rating agencies that have based their views largely on comparing allowed Returns on Equity for utilities of similar size and overall risk.

5.2 Debt Rate

11. THESL accepts, for the purpose of this Application and electricity distribution rates effective May 1, 2006, the Board's methodology for setting the debt rate based on the forecast of the Long Canada Bond Rate, and based on the most current data available. THESL's weighted debt costs and debt rate are provided in Schedule 5-1.

12. THESL recognizes the difficulty of establishing a cutoff date for determining the debt rate in time to allow an LDC to calculate its weighted average cost of capital. However, THESL notes that because the Board's methodology is based on a point-in-time consensus forecast, it does not adequately address major changes to interest rates beyond the cutoff date. THESL points out that Canadian bond markets rallied very soon after the Board's consensus forecast was issued. Had a consensus forecast view been developed even a month later, the debt rate may have

been a half percentage point lower than the OEB's proposed deemed debt rate of 5.8 percent. THESL recognizes that the converse logic also applies should interest rates rise soon after the consensus forecast is issued. However, in either case, THESL submits that the Board's current methodology risks sending inappropriate interest rate signals for a significant and extended period of time (i.e. until the next re-basing period). Therefore, in reviewing the debt rate, THESL encourages the Board to consider a mechanism that addresses significant changes to interest rates after a consensus outlook has been issued. THESL believes that a half a percentage point, or higher, change in interest rates constitutes a significant change.

13. Accordingly, THESL emphasizes that a comprehensive review of the overall methodology for establishing a debt rate that will provide an adequate return on rate base, effectively deal with bond market volatility, and send appropriate signals to LDCs for capital investment decisions, is urgently needed.

5.3 Capital Structure

14. THESL is not proposing to change the current deemed capital structure of 65 percent debt and 35 percent equity at this time, prior to a comprehensive review of the allowed return on equity and cost of debt.

15. Despite THESL's acknowledgement of a possible positive correlation between utility size and its ability to assume increasing levels of debt, the deemed debt-to-equity ratio did hamper access to working capital for

THESL in the recent past. The terms and conditions of short-term financing, the cost of this financing, and the amount of short-term financing available to THESL for working capital were more limited and restrictive than if THESL had a lower leverage ratio.

16. While current capital market conditions for additional debt capital remain favourable, it is expected that long-term interest rates will at some point turn higher. Typically, higher long-term interest rate environments are accompanied by generally tighter credit conditions that, other things being equal, tend to favour borrowers with lower leverage ratios. Therefore, should a need to borrow for purposes of replacing or expanding distribution plant arise at the same time as monetary conditions turn restrictive, the current relatively high leverage ratio may compromise THESL's ability to borrow at favourable rates and directly impact customer rates.

5.4 Working Capital Allowance

17. THESL accepts the Board's methodology with respect to setting the Working Capital Allowance, but since it is filing on the basis of an FTY, forecast wholesale kWh and forecast 2006 cost of power values have been used to determine the working capital allowance. However, it is important for the Board to note that the current basis for setting the working capital allowance does not adequately deal with volatility in the Ontario electricity spot market, nor does it adequately deal with prudential requirements set by the IESO.

18. In this regard, THESL's parent company has been obliged (and continues) to arrange for short-term lines and letters of credit over and above the working capital allowance estimated for THESL. It is also instructive to note that the tremendous spot market volatility experienced prior to the passage of Bill 210 brought out the inherent weaknesses of basing a working capital allowance on historical cost of power plus controllable expenses. It is largely because much of the Ontario electricity spot market is currently paying some form of a contract price for electricity that THESL continues to accept the current working capital allowance methodology. However, the current level of spot market prices, the continuation of the IESO's prudential scheme, and the Province's commitment to return to full spot market pricing at a future date, all point to the need for the Board to review the current working capital allowance methodology.

SCHEDULE 5-1: WEIGHTED DEBT COST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
No.	**Description**	**Debt Holder**	**Is Debt Holder (Y/N)**	**Date of Issuance**	**Principal**	**Term (Years)**	**Actual Rate**	**Debt rate used for weighted debt rate cost**
1	Long-Term promissory note due 2013	Parent Company (THC)	Yes	May 7, 2003	$ 980,230,955	10-years	6.80%	6.80%
2	Long-Term debentures due 2013	Parent Company (THC)	Yes	May 7, 2003	$ 180,000,000	10-years	6.17%	6.17%
Total					**$ 1,160,230,955**			**6.70%**

Note: For the second debt issue, the debt rate reflects the inclusion of one-year's worth of issuance costs equal to $298,834.

SCHEDULE 5-2: ACTUAL CAPITAL STRUCTURE OF THESL AS AT DECEMBER 31, 2004

Line		Dollars	%	Deemed Structure	Cost Rate
(1)	Long Term Debt	$ 1,160,230,955	62.18%	65.00%	6.70%
(2)	Unfunded Short Term Debt	$ -			
(3)	Total Debt (3) = (1) + (2)	**$ 1,160,230,955**			
(4)	Preferred Shares	$ -			
(5)	Common Equity	$ 705,682,000	37.82%	35.00%	9.00%
(6)	Total Equity (6) = (4) + (5)	**$ 705,682,000**			
(7)	Total (7) = (3) + (6)	**$ 1,865,912,955**			

CHAPTER 6 – DISTRIBUTION EXPENSES

6.0 Introduction

1. In this Application, THESL files its distribution expenses for the years 2002, 2003 and 2004 consistent with the results filed with the OEB in the second quarter of 2005, including restatements for years 2002 and 2003. Explanation for significant variances between years is included as Appendix 6-A, including the impact of a change in accounting policy for asset retirement obligations.

2. THESL also files projected expenses for the years 2005 and 2006. The adjustments and assumptions used to derive these projections are described in Appendix 6-B.

6.1 Definition of Distribution Expenses

3. THESL conducts no non-distribution activity and, as a result, only distribution expenses are used to calculate THESL's 2006 revenue requirement.

6.2 Detailed Reporting for Specific Distribution Expenses

6.2.1 Insurance Expenses

4. THESL currently maintains insurance programs designed to protect against catastrophic losses. In general, certain risks can be reduced through a variety of loss prevention techniques. Risks can be contractually transferred to another company, or risks can be transferred to an insurance company. THESL's insurance policies are continually evolving with changes designed to enhance the overall program.

5. In 2003, actual insurance costs rose $430,236 compared to 2002. The most notable increase was in the primary and excess liability and automobile insurance policies. The increase in the first two policies was a direct result of higher premiums to offset large claim settlements, in particular the Walkerton Settlement. The Walkerton Settlement negatively impacted the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") reciprocal structure as the local distribution company ("LDC") in Walkerton also provided water services to the town.

6. Effective January 1, 2004, THESL left the MEARIE program, and placed its general liability and automobile insurance with the commercial insurance market. This decision has enabled THESL to increase overall policy limits and conditions, lower premium costs, and redefine its loss prevention programs.

7. THESL notes that one of the main reasons for leaving the MEARIE reciprocal structure in 2004 was the inability to obtain higher limits from

MEARIE at a favourable price. An increase in overall insurance limits for the company had been strongly recommended by an independent third party assessor as part of underwriters' due diligence process into THC's inaugural debt issue in 2003.

8. THESL would also like to bring to the Board's attention that, in filing its 2004 RRR cost data, two insurance expense elements were inadvertently included for THESL's affiliated companies. These expense elements are identified in the attached Schedule 6-1: Insurance Expenses, in the 2004 numbers, and have been excluded for 2005 and 2006. The expense elements pertain to $17,510 paid in premiums for errors and omissions coverage by THESI and $249 paid in premiums for primary liability coverage by THTI.

9. THESL currently manages all third party claims with the help of an independent insurance claims adjuster. Additionally, higher deductibles have been implemented in conjunction with general liability policies. As a result, claim payments can, and do, fluctuate on a yearly basis. The establishment of a claims reserve is required to offset any potential significant losses.

10. THESL maintains a self-funded insurance plan for third party liability and property claims that fall below $100,000 per occurrence. The figures in Schedule 6-1 below include all filed and open claims, as well as an estimate for claims that have been incurred but not yet reported.

11. Directors and officers insurance provides financial protection to THESL directors and officers in the event they are sued in connection with the performance of their duties. Costs continue to rise with the growing incidence of litigation and insurers are adding more and more exclusions

and limitations to their policies. Accordingly, the 2006 forecast is THESL's best estimate of the potential cost of adequate directors and officers insurance.

12. Effective August 1, 2004, THESL placed its property, boiler and machinery insurance with Factory Mutual Global ("FM"). FM offers state-of-the-art loss prevention engineering and research. However, THESL anticipates that costs will continue to rise as a result of higher property values, higher replacement values for machinery and equipment and appraisal services. Nevertheless, it is instructive to note that, over the years, FM has developed a strong reputation in insuring electricity and gas distribution companies and has a robust loss prevention program for its utility customers. THESL believes that judicious implementation of many of FM's recommendations will lower the incidence of property loss in the coming years.

13. The 2005 premium expenses include a mix of both actual and estimated values. All liability figures in Schedule 6-1 are actual values and are in line with previous year results. Increases in directors and officers insurance as well as claims paid and reserved have been noted above.

14. As shown in Schedule 6-1, THESL is forecasting a relatively small increase in overall insurance costs for 2006, since, in general, it is anticipated that the increase in claims paid is offset by the absence of any claims reserve in 2006. However, THESL submits that, insurance premiums alone are forecast to increase by about 18 percent in 2006 compared to 2005. Nevertheless, THESL is pleased to note that its overall insurance costs have been held relatively constant for the past five years, and the company continues to improve and evolve its

insurance program with the primary goal of protecting its distribution plant for the ultimate benefit of ratepayers.

6.2.2 Bad Debt Expense

15. Attached, is Schedule 6-2: Bad Debt Expense, that summarizes reported bad debt expenses for the years 2002, 2003 and 2004, and projects bad debt expenses for 2005 and 2006.

16. There were no material bad debt occurrences in 2004. Materiality is defined as an amount exceeding 0.2 percent of the total distribution expenses, as calculated by the model. As a result, projections for 2005 and 2006 have been maintained at the current 2004 level. No adjustments were required to remove any unusual bad debt.

6.2.3 Information Technology Expenses

IT Organization

17. THESL purchases required technology services from THC through a service level agreement. To realize economies of scale and to ensure optimal operations, all technology costs are centralized within THC's information technology ("IT") division. These costs include all support costs for corporate systems such as enterprise wide infrastructure servers, storage systems, email, and THESL specific applications such as billing, SCADA, and geospatial systems.

18. The IT division is organized around four groups: (1) infrastructure operations, (2) system delivery for electricity distribution, (3) system

delivery for customer care, and (4) system delivery for corporate services.

19. The infrastructure operations group is responsible for the development and operation of infrastructure such as data and voice network, Unix and Intel servers and operating system software, enterprise storage systems, database and middleware software, data center operations, backup and recovery, as well as all desktop support.

20. The system delivery groups provide existing system support and implementation of new systems service to specific client groups.

21. System Delivery Managers are accountable to both the Chief Information Officer and to business unit Vice-Presidents for the performance of existing systems and deliverables for approved IT projects. Performance is evaluated using key performance indicators and monthly project status reviews.

22. An Enterprise Architect reports directly to the Chief Information Officer and supports enterprise-wide systems and data architecture planning. In accordance with industry best practice, this position ensures that acquired systems are evaluated against overall enterprise architecture considerations for optimal deployment and support of current and future business needs while minimizing ongoing support costs.

23. THESL is the primary user of IT services from THC. In 2004, support costs of $17.7 M were allocated to THESL based on its usage of application services, customer bills and computer equipment. These costs are charged to THESL under seven (7) services:

a. workstation;

b. network access;

c. telephony;

d. corporate application services subscription;

e. electrical distribution application subscription;

f. customer care application subscription; and

g. customer bill production.

24. Where THESL is the only user of a service, costs are allocated solely to THESL. Where services are shared by a number of affiliates, costs are charged back based on actual consumption (where drivers are readily identifiable without causing excessive overhead or administrative costs) or allocated based on historical information. Table 6-3 below summarizes the 2004 IT cost allocators.

Table 6-3 – 2004 IT Cost Allocation

	IT Service	**Allocator**	**THESL Allocation (%)**
1.	Workstation	# of workstations	93%
2.	Network Access	# of email userids	92%
3.	Telephony	# of telephone lines	91%
4.	Corporate Application Subscription	historical usage	93%
5.	Electrical Distribution Application Subscription	sole user	100%
6.	Customer Care Application Subscription	sole user	100%
7.	Customer Bill Production	sole user	100%

24. Table 6-4 below summarizes 2004 IT expenses of $17.7 M incurred in the seven services by OEB account.

Table 6-4 – IT Expense by OEB Account

OEB Account	2004 IT Expenses
3500-Distribution Expenses - Operation	$ 4.2 M
3650-Billing and Collecting Total	$1.6 M
3800-Administrative and General Expenses	$11.9 M
Total	**$17.7 M**

25. IT expenses of $4.2 M under the 3500-Distribution Expenses account include the cost of supporting systems and processes such as: SCADA system, GIS, computerized drafting system, electronic document system, transformer load management, asset equipment records and asset maintenance management, construction work planning, work scheduling, work tracking and reporting.

26. The $1.6 million under account 3650-Billing and Collecting represents system and process support costs such as: meter installation and changes, meter reverification, meter reading, billing, retailer settlement, e-bills, payment processing, customer web access, delinquency tracking, collection, revenue reporting, and customer inquiries.

27. The $11.9 million under account 3800-Administrative and General Expenses represents costs of enterprise applications such as: email, office software, corporate portal, intranet, financial systems, general ledger, accounts payable, accounts receivable, treasury, inventory management, material requisition and purchasing, vehicle management system, payroll interface, human resource system, training systems,

network infrastructure, desktop computers, plotters, printers, internet access, audit and security compliance, Affiliate Relationships Code ("ARC") compliance, backup and disaster recovery services, and help desk services. It also includes bill and notice production, telephone systems and Bell line charges including SCADA telecom charges, and call centre telephony applications such as agent routing, interactive voice response, and computer telephony integration.

28. Since amalgamation of the six former utilities in 1998, with the exception of two systems (SCADA and GIS), THC has consolidated its computer systems and infrastructure, resulting in a significant reduction of IT expenses and business process streamlining. The consolidation of GIS and SCADA are in a multi-year conversion program due to their complexity and potential impact on operations. The conversion is expected to be completed in 2007.

29. The IT division within THC adheres to industry best practices for IT. These practices include enterprise architecture planning, the use of enterprise technology standards, technology investment portfolio management and business case evaluation. It has implemented industry best practice processes for technology services organizations from the Information Technology Infrastructure Library ("ITIL") to ensure computer systems support THESL's business processes with a high degree of reliability and at optimal cost.

30. THC IT staff members regularly participate in Ontario-wide working groups and committees to facilitate the development of province-wide standards such as electronic business transaction ("EBT") standards. Throughout market opening, IT staff collaborated with other LDCs to

research and investigate cost-effective approaches for billing and settlement operations. IT staff members also participate in a coalition of LDCs to investigate unified approaches for smart meter implementation.

31. Whenever and wherever possible, the IT division follows an industry best practice of using external suppliers for commodity services when in-house staff members are not expert or cost effective in a certain area. It currently out-sources desktop support (i.e. help desk) services, bill printing services and equipment maintenance to external service providers. THESL submits that the technology costs represented in this Application are reasonable and treated in a manner consistent with the Accounting Procedures Handbook ("APH") and the DRH.

6.2.4. Advertising, Political Contributions, Employee Dues, Charitable Donations, Meals/Travel and Business Entertainment, Research and Development

Advertising Expenses

32. THESL's advertising expenses in 2002 focused on educating consumers about changes to electricity rates, rate structures and the electricity market in general. Types of communication included a series of bill inserts that explained a new bill format as well as adjustments to the rates; letters targeted to specific customer classes announcing and explaining rate changes; flyers and advertisements announcing public "town hall meetings" where THESL staff explained the new market structure to homeowners and small business owners; and the cost of

audio-visual services (microphones and speakers) used at the town hall meetings.

33. THESL's advertising efforts in 2003 continued to focus on public education about the electricity marketplace and involved the continuation of town hall meetings and associated communications in support of them. Bill inserts communicated information about rates and energy conservation, and an advertisement announcing a rate application was published as directed by the OEB.

34. THESL's advertising in 2004 included bill inserts outlining rates information as well as web site development focused on assisting customers in understanding bill format changes. Public information materials such as bill inserts and newspaper advertisements about energy conservation initiatives were published. These included the promotion of home energy audits and the use of seasonal LED lights.

35. THESL's 2005 advertising expenses are in support of programs that are already underway and some that are scheduled to roll out before year-end. All programs have a conservation focus. Communications, including advertising, are designed to benefit customers, in an attempt to educate them on how to conserve energy or by offering energy efficiency tips that they can implement in their homes or businesses.

36. 2005 marked the introduction of CDM programs in THESL. As such, THESL's Marketing, Communications and Public Affairs team has committed to developing and implementing marketing and communications plans to successfully deliver these programs to market. THESL's communications goal is to have customers understand that electricity conservation can be easy and to provide customers with

energy efficiency tips, while concurrently engaging different program partners to assist in building credibility and impact for each CDM program.

37. Expenses in 2005 are incurred for the design of programs, development of marketing and communications materials, and purchase of media space. Costs outlined for 2005 include actual costs, estimated costs based on program development including partner estimates and forecasts based on elements of the marketing plan that have yet to be executed.

38. THESL's 2006 advertising expenses as outlined in the marketing plan forecasts an increase in advertising expenses as the momentum for conservation programs continues to build.

39. THESL's Marketing Communications and Public Affairs team anticipates an increased interest and awareness of CDM initiatives and programs in 2006. THESL is planning to increase the number of programs taken to market in 2006, and an associated increase in advertising expenses.

40. Attached, as Appendix 6-C is a summary of THESL actual and projected advertising expenditures for 2002 to 2006.

Political Contributions

41. THESL's distribution expenses in each year do not include any amounts for political contributions.

Employee Dues

42. THESL's distribution expenses in each year do not include any amounts for employee memberships in organizations that are recreational or social in nature, other than fees or dues related primarily to health and fitness. In the years 2002 to 2005, the fees or dues related primarily to health and fitness were not available to unionized employees. The availability of such a program to unionized employees is an issue that is dealt with through labour contract negotiations. The current labour contract expires on January 31, 2006.

Charitable Contributions

43. Attached is Schedule 6-3: Charitable Donations, that details amounts paid as charitable donations.

Meals/Travel And Business Entertainment Expenses

44. THESL maintains three written policies for management approval of meals, travel and entertainment. Specifically, they are as follows:
    - Business Expenditure Reimbursement Policy – applicable to management employees (Attached as Appendix 6-D)
    - Collective Agreement, Section 33.31 to 33.32 – applicable to inside/outside unionized employees (Attached as Appendix 6-E)
    - Collective Agreement, Article 29 – applicable to engineer employees (Attached as Appendix 6-F)

45. Internal measures exist that ensure staff meals, travel and entertainment-related expenses included in this filing meet approval by THESL's management, based upon a consistently applied corporate policy.

46. All employees are required to obtain approval for any expenses relating to meals, travel and entertainment-related expenses, and to ensure that the expenses fall within the guidelines of the respective policy or Collective Agreement.

47. Management employees are required to follow the expense reporting procedures, as outlined in the policy.

48. Unionized employees are required to submit their information on a timesheet, and get approval from their supervisor, as outlined in the Collective Agreement.

Research and Development

49. THESL's revenue requirement does not include any incremental expenditures relating to research and development. While THESL has claimed and will continue to claim, certain investment tax credits against income taxes payable, the underlying research and development expenses consist solely of existing payroll costs incurred in the ordinary course of business and therefore do not contribute to any additional revenue requirement.

6.2.5 Employee Total Compensation

50. Attached as part of this Application is a completed Schedule 6-4: Employee Compensation, that provides details by employee-type for the number of employees, and the compensation dollars for average yearly

base wage, average yearly overtime, average yearly incentive, and average yearly benefits, for the years 2002, 2003 and 2004 and projections for 2005 and 2006.

51. THESL's reported number of employees and compensation represents full-time equivalent ("FTE") employees of THESL combined with its parent corporation THC. Activities supporting THESL represent the most significant function of THC employees.

52. The reported number of employees includes all FTE employees who received any form of compensation, irrespective of active employment status (for example departed employees who continued to receive payments or benefits from THESL or THC).

53. The estimate of benefits includes statutory benefits funded by the employer (i.e. Canada Pension Plan, Employment Insurance and Employer Health Tax) in addition to employer contributions to Ontario Municipal Employees Retirement System ("OMERS") and other company benefits.

54. THESL includes in its Application employee incentive plan expenses. Attached as part of this Application is a completed Schedule 6-5 that outlines the plan description, the plan performance measures and the plan's annual costs.

6.2.6 Pensions and Post-Retirement Benefits

Pensions: OMERS Members

55. Attached as part of this Application is a completed Schedule 6-6: OMERS Pension Expense and Post-Retirement Benefits, that provides OMERS detail for 2002 to 2006. Schedule 6-7 is not applicable to THESL.

Post-Retirement Benefits

56. Attached, as a part of Schedule 6-6, is information regarding:

- Current account treatment of post-retirement benefits;
- Treatment of past changes in accounting policy regarding post-retirement benefits, and any related one time expenses, including amortization policy; and
- Treatment of changes in actuarial value in post-retirement benefits.

6.2.7 Distribution Expenses Paid to Affiliates

Affiliate Transactions

57. THESL is a 100 percent subsidiary of THC, which is also the sole shareholder in the following affiliates: THESI, THTI and THSLI.

58. In 2004, THESL incurred expenses paid to THC ($80,324,000 for corporate and management services) and to THESI ($1,634,000, for electricity supply and project management services). Attached is a

completed Schedule 6-8: Distribution Expenses Paid to Affiliate(s), that details affiliate activity, value and pricing basis.

59. In 2004, THESL recovered expenses paid by THTI ($4,938,000 for pole attachments and duct rentals), THESI ($4,624,000 for water heater related services), THC ($1,815,000 for procurement and fleet services) and THSLI ($405,000 for procurement and fleet services), as summarized in Schedule 6-8. Costs recovered from affiliates were either credited to THESL's distribution expenses or included in THESL's service revenue, thereby reducing its base revenue requirement.

Shared Services

60. Attached is a completed Schedule 6-9 that details distribution expenses incurred through the sharing of services or resources with affiliates. The costs allocated to THESL were determined on the basis of actual costs incurred within THC to deliver the service, and the determinations of the individual service providers with respect to the portion of costs attributable to THESL. The basis of these determinations varied based on the type of service. For example, human resources cost allocation is based on headcount and facilities cost allocation is based on square footage.

61. THESL is confident its cost-based approach to allocations of shared services is appropriate and compliant with both the APH and the ARC.

Outsourced Distribution Services

62. THESL does not outsource more than 50 percent of its distribution services, as measured by the cost of outsourced services (excluding

shared services purchased from THC) in relation to total controllable distribution expenses. Accordingly, Schedule 6-10 is not applicable and therefore not included as part of this Application.

SCHEDULE 6-1: INSURANCE EXPENSES

Toronto Hydro–Electric System Limited
Insurance Premiums

Type of Insurance	# of Insurers	2002 Actuals	2003 Actuals	2004 Actuals	2005 Estimate	2006 Forecast
Property / Boiler & Machinery	1	$ 600,496	$ 582,553	$ 523,446	$ 500,000	$ 600,000
Primary Liability	1	$ 1,787,284	$ 2,057,355	$ 419,040	$ 405,000	$ 425,000
Excess Liability	2	$ 200,000	$ 243,000	$ 807,840	$ 883,707	$ 1,000,000
Garage Liability	1	$ -	$ 6,102	$ -	$ 18,000	$ 20,000
Automobile Liability	1	$ 290,010	$ 335,143	$ -	$ -	$ -
Directors & Officers	1	$ 88,000	$ 118,800	$ 120,780	$ 130,000	$ 150,000
Excess D&O	2	$ 35,200	$ 86,400	$ 86,850	$ 90,000	$ 100,000
Crime	1	$ 19,313	$ 22,815	$ 22,687	$ 22,000	$ 25,000
Social Club Liability	1	$ 4,000	$ 2,648	$ -	$ -	$ -
Travel Accident	1	$ 750	$ 473	$ -	$ -	$ -
Aon Reed Stenhouse	1	$ -	$ -	$ -	$ 108,000	$ 120,000
Claims paid		$ -	$ -	$ 250,000	$ 475,000	$ 660,000
Claims reserved		$ -	$ -	$ 1,100,000	$ 400,000	$ -
Errors & Ommissions -- THESI		$ -	$ -	$ 17,510	$ -	$ -
Primary Liability -- THTI		$ -	$ -	$ 249	$ -	$ -
Auto Policy Rebate		$ -	$ -	(17,870)	$ -	$ -
Grand Total		**$ 3,025,053**	**$ 3,455,289**	**$ 3,330,532**	**$ 3,031,707**	**$ 3,100,000**

Notes:

2004:
The auto policy was transferred to Toronto Hydro's Fleet cost center in 2004. Therefore, the auto insurance policy is included in general insurance expenses for 2002 and 2003, but not for 2004 and beyond.

In its RRR filing into 2004 Insurance Expenses, two expense categories were filed in error. Currently, Toronto Hydro Corporation arranges insurance policies for all of its subsidiary companies, and then allocates the pro rata premium costs to the affiliated companies. In its RRR filing into 2004 expenses, $17,510 in Errors and Ommissions premiums were included in THESL's filing, but should have been allocated to Toronto Hydro Energy Services Inc. Additionally, $249 was similarly included in error for a Primary Liability policy for Toronto Hydro Telecom Inc. Accordingly, recovery for these expense elements is not being sought in the current Rate Application.

Primary Excess Liability:
Significant decrease as a result of transferring liability insurance from MEARIE Group (reciprocal association) to competitive commercial market.

Self-Insurance Plan:
Self-funded plan for third party liability claims and property claims which fall below $100,000 on a per occurrence basis. Includes all open claims that have been filed and incurred but not reported claims.

2006 Forecast:
Property / Boiler & Machinery: Increase due to higher property values, higher replacement costs for machinery and costs associated with appraisal fees
Primary/Excess Liability: Expected increase in overall limits
Directors and Officers: Continuing higher costs as a result of large industry claims
Claims Paid: Estimation based on higher claims costs based on historical trends

SCHEDULE 6-2: BAD DEBT EXPENSE

Account 5335 Bad Debt Expenses by Customer Class	2002 (actual)	2003 (actual)	2004 (actual)	2005 (projected)	2006 (projected)
Residential <50kW demand	$ 4,974,117	$ 4,000,412	$ 4,259,357	$ 4,258,914	$ 4,258,914
General Service > 50kW demand	$ 4,609,923	$ 3,707,511	$ 3,947,497	$ 3,947,086	$ 3,947,086
Others (non-energy related accounts)	$ 1,517,902	$ (1,153,258)	$ (1,219)	$ -	$ -
Total	**$ 11,101,942**	**$ 6,554,665**	**$ 8,205,635**	**$ 8,206,000**	**$ 8,206,000**

SCHEDULE 6-3: CHARITABLE DONATIONS

1. THESL has analyzed its charitable contributions since 2002 in order to identify and separate tax-receipted donations made to charitable organizations. Actual and planned donations in the period 2002-2006 range from $35,000 to $205,000. They are as follows:

Year	Donation	Winter Warmth	Non-Eligible
2002	$35,000		
2003	$55,000		
2004	$205,000	$100,000	
2005	$157,500	$100,000	
2006	$157,500	$100,000	$57,500

2. Beginning in 2004 an annual donation to the United Way Winter Warmth Fund was initiated. The fund provides assistance to low income customers who have difficulty paying their electricity bills during the heating season.
3. Non-eligible contributions have not been included in THESL's 2006 revenue requirement.

SCHEDULE 6-4: EMPLOYEE COMPENSATION

Number of Employees - Full-Time Equivalents (FTEs)	2002	2003	2004	2005	2006
Executives	18	18	19	16	16
Managerial	40	47	49	42	44
Management/Non-Union	299	290	284	318	328
Unionized	1,215	1,203	1,212	1,192	1,192

Compensation - Average Yearly Base Wage	2002	2003	2004	2005	2006
Executives	$ 160,228	$ 144,911	$ 128,349	$ 165,172	$ 174,061
Managerial	$ 101,945	$ 97,646	$ 100,004	$ 114,106	$ 116,815
Management/Non-Union	$ 76,494	$ 76,007	$ 78,723	$ 82,219	$ 83,886
Unionized	$ 62,397	$ 62,127	$ 63,079	$ 64,542	$ 66,644

Compensation - Average Yearly Overtime	2002	2003	2004	2005	2006
Executives	$ -	$ -	$ -	$ -	$ -
Managerial	$ 86	$ -	$ -	$ -	$ -
Management/Non-Union	$ 6,224	$ 3,030	$ 2,807	$ -	$ -
Unionized	$ 4,901	$ 5,010	$ 4,699	$ 6,072	$ 6,490

Compensation - Average Yearly Incentive	2002	2003	2004	2005	2006
Executives	$ 35,646	$ 47,648	$ 42,143	$ 52,875	$ 56,532
Managerial	$ 6,930	$ 11,791	$ 12,441	$ 14,841	$ 15,003
Management/Non-Union	$ 3,717	$ 4,118	$ 4,356	$ 4,268	$ 5,080
Unionized	$ 84	$ 78	$ 81	$ -	$ -

Compensation - Average Yearly Benefits	2002	2003	2004	2005	2006
Executives	$ 48,118	$ 85,121	$ 70,615	$ 56,520	$ 66,051
Managerial	$ 27,799	$ 28,430	$ 31,618	$ 34,710	$ 38,047
Management/Non-Union	$ 21,973	$ 28,187	$ 25,329	$ 25,988	$ 26,513
Unionized	$ 16,627	$ 18,399	$ 22,435	$ 22,503	$ 23,300

Note: Data represents THESL and THC

SCHEDULE 6-5: EMPLOYEE INCENTIVE PLAN EXPENSE

Description

1. Toronto Hydro rewards the contribution of management employees on the basis of corporate and business unit targets. Attached, as Appendix 6-G of this Application is the 2005 Performance Pay Guidelines document that provides more detailed information regarding corporate and business unit targets. These targets are described on both the THC and THESL scorecards and include the following broad performance categories: operations, finance, customer and people.

Performance Measures

2. Appendix 6-G details the specific performance measures for each type of employee incentive plan.
3. Of both the THC and THESL incentive plans, financial commitment (found only on the THC scorecard), is composed of a net income component and is the only measure reflective of shareholder value.

Annual Cost(s)

4. Performance incentive pay ranges from 6 percent - 16 percent of annual salary for the majority of employees up to and including senior managers, from 20 percent - 35 percent for executives and 40-50 percent for CEO and CAO. In total, 420 management employees are eligible to receive performance incentive pay at a cost of approximately $3.5

million per year. Of that amount, approximately $68,000 is the 2005 incentive pay associated with net income. This amount has been excluded from the revenue requirement. The remainder of corporate and business unit incentive pay is associated with performance that benefits the ratepayer.

SCHEDULE 6-6: OMERS PENSION EXPENSE AND POST-RETIREMENT BENEFITS

1. THESL's employees are members of the OMERS. The following summarizes related actual and projected information for 2002 to 2006:

A. Pension

Pension	2002	2003	2004	2005	2006
Pension premiums	-	2,451,226	7,757,355	8,362,078	9,403,055
Adjustments	-	-	-	-	-
Less: amount capitalized	-	947,925	2,908,304	3,283,430	3,544,075
Amount expensed in each year	-	1,503,301	4,849,051	5,078,648	5,858,980

2. Note: Because of a surplus under the plan, a contribution holiday had been in effect from August 1998 to December 2002. Current service pension cost contributions recommenced in January 2003 at one-third of the full contribution rates. Beginning January 1, 2004, the Corporation returned to full contribution rates.

B. Post-Retirement Benefits Expense

Post Retirement Benefits	2002	2003	2004	2005	2006
Post-Retirement Benefits Cost	7,370,200	10,106,400	10,917,537	11,727,160	12,173,640
Adjustment	-	-	-	-	-
Less: Amount capitalized	3,016,860	4,509,601	4,803,711	4,944,741	4,819,123
Amount expensed in each year	4,353,340	5,596,799	6,113,826	6,782,419	7,354,517

C. Post-Retirement Benefits Accounting Information

Current Accounting Treatment of Post-Retirement Benefits

3. 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.

4. 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

5. There were no past changes in accounting policy or any related one-time expenses.

Treatment of Changes in Actuarial Value in Post-Retirement Benefits

6. 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 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

7. The post-retirement benefits disclosure is in accordance with CICA Handbook Section 3461 "Employee Future Benefits".

SCHEDULE 6-8: DISTRIBUTION EXPENSES PAID TO AFFILIATES

Affiliate Names	Activity	2006 Estimated Value	2005 Estimated Value	2004 Value	2003 Value	2002 Value	Basis Pricing	Price Determination Policy
Toronto Hydro Corporation (THC)	THESL purchases corporate and management services from THC.	51,342,380	50,635,713	80,324,000	75,876,000	32,052,000	Cost Based Pricing	Allocations of cost are determined based proportion of overall provider costs supporting each entity.
Toronto Hydro Energy Services Inc. (THESI)	THESL purchases project management services from THESI.	-	75,058	569,000	3,068,000	26,400,000	Market Based Pricing	Based on market pricing as an arms length transaction.
Toronto Hydro Energy Services Inc. (THESI)	THESL purchases electricity from THESI.	-	402,774	1,065,000	1,004,000	767,000	Market Based Pricing	Based on market pricing as an arms length transaction.
Total		**51,342,380**	**51,113,545**	**81,958,000**	**79,948,000**	**59,219,000**		

Summary By Entitiy

Toronto Hydro Corporation (THC)		51,342,380	50,635,713	80,324,000	75,876,000	32,052,000
Toronto Hydro Energy Services Inc. (THESI)		-	477,832	1,634,000	4,072,000	27,167,000
Total		**51,342,380**	**51,113,545**	**81,958,000**	**79,948,000**	**59,219,000**

SCHEDULE 6-8: DISTRIBUTION EXPENSES RECOVERED FROM AFFILIATES

Affiliate Names	Activity	2006 Estimated Value	2005 Estimated Value	2004 Value	2003 Value	2002 Value	Basis Pricing	Price Determination Policy
Toronto Hydro Energy Services Inc. (THESI)	THESL provides water heater services to THESI.	5,346,952	5,318,607	4,624,000	4,241,000	3,451,000	Cost Based Pricing	At transfer prices determined by the Affiliate Relationships Code.
Toronto Hydro Telecom Inc. (THTI)	THESL provides procurement and fleet services to THTI.	232,528	225,755	84,000	-	-	Cost Based Pricing	Allocations of cost are determined based on time spent supporting a given corporate entity.
Toronto Hydro Corporation (THC)	THESL provides procurement and fleet services to THC.	797,273	774,051	1,815,000	-	-	Cost Based Pricing	Allocations of cost are determined based on time spent supporting a given corporate entity.
Toronto Hydro Streetlighting Inc.(THSLI)	THESL provides procurement and fleet services to THSLI.	459,274	445,897	405,000	-	-	Cost Based Pricing	Allocations of cost are determined based on time spent supporting a given corporate entity.
Toronto Hydro Telecom Inc. (THTI)	THESL bills THTI for pole attachment and duct rental services.	2,858,496	5,109,564	4,854,000	4,605,000	7,668,000	Market Based Pricing	Pursuant to rates set by the CRTC.
Total		**9,694,522**	**11,873,874**	**11,782,000**	**8,846,000**	**11,119,000**		

Summary By Entitiy

Toronto Hydro Corporation (THC)		797,273	774,051	1,815,000	-	-
Toronto Hydro Energy Services Inc. (THESI)		5,346,952	5,318,607	4,624,000	4,241,000	3,451,000
Toronto Hydro Telecom Inc. (THTI)		3,091,024	5,335,319	4,938,000	4,605,000	7,668,000
Toronto Hydro Streetlighting Inc.(THSLI)		459,274	445,897	405,000	-	-
Total		**9,694,522**	**11,873,874**	**11,782,000**	**8,846,000**	**11,119,000**

SCHEDULE 6-9: DISTRIBUTION EXPENSES INCURRED THROUGH SHARING SERVICES WITH AFFILIATES

Affiliate Names (Shared Service Providers)	Activity	2006 Estimated Value (3)	2005 Estimated Value (1)	2004 Value	2003 Value	2002 Value	Allocation Basis
Toronto Hydro Corporation (THC)	Legal	1,685,945	1,653,698	1,504,987	1,859,627	2,104,342	
Toronto Hydro Corporation (THC)	Organizational Effectiveness	2,923,086	2,865,490	4,335,358	4,839,266	5,126,689	As described below.
Toronto Hydro Corporation (THC)	Finance & Treasury	6,805,142	6,710,524	6,133,395	8,879,642	9,191,004	As described below.
Toronto Hydro Corporation (THC)	Regulatory Services	3,730,611	3,713,898	1,938,942	2,436,553	4,051,404	As described below.
Toronto Hydro Corporation (THC)	Environment Health & Safety	1,907,203	1,875,138	1,688,811	2,658,062	592,803	As described below.
Toronto Hydro Corporation (THC)	Information Technology	19,643,341	19,313,087	17,788,609	21,370,714	-	As described below.
Toronto Hydro Corporation (THC)	Facilities (2)	-	-	29,311,455	28,134,751	-	As described below.
Toronto Hydro Corporation (THC)	Corp Shared Services	11,456,402	11,357,591	11,347,772	930,493	10,985,938	As described below.
Toronto Hydro Corporation (THC)	Corporate Communications	3,190,650	3,146,287	4,903,141	4,766,545	-	As described below.

The primary allocation basis for these costs from THC, the corporate entity where all of these shared services reside, is an estimation of how much work will be done by the shared service for the various entities. This is achieved through discussions at the senior executive level. A percentage basis is derived from these discussions, and used as the basis for the budget and for allocating actual costs. At the end of a fiscal year, a true-up is performed whereby all overages and underages in the Shared Services are apportioned out proportionately to the recipients.

(1) 2005 balances are per Toronto Hydro Board Approved Budget.

(2) Facilities and Telecommunications have been transferred back to THESL, and those costs reside there directly.

(3) 2006 is derived from the 2005 budget amount grossed up for an estimated increase in payroll as a proportion of overall costs. Other costs are deemed to be equivalent to the 2005 budget.

3.00% Estimated Payroll increase for 2005.

APPENDIX 6-A: 2002-04 DISTRIBUTION EXPENSES - VARIANCE ANALYSIS

($ millions)	Actual 2004	Actual 2003	2004 vs 2003 Var $	2004 vs 2003 Var %	Actual 2003	Actual 2002	2003 vs 2002 Var $	2003 vs 2002 Var %
Operation	40.6	38.2	2.4	6.2%	38.2	42.2	(4.0)	(9.4%)
Maintenance	23.6	22.8	0.8	3.6%	22.8	20.5	2.3	11.2%
Billing and Collection	32.7	29.3	3.4	11.6%	29.3	33.1	(3.8)	(11.4%)
Community Relations	2.6	2.4	0.2	8.5%	2.4	4.1	(1.7)	(41.4%)
Administrative and General	51.6	53.3	(1.7)	(3.3%)	53.3	47.6	5.7	12.0%
Total Controllable Expenses	*151.0*	*146.0*	*5.1*	*3.5%*	*146.0*	*147.4*	*(1.5)*	*(1.0%)*
Other Distribution Expenses	13.7	13.2	0.6	4.3%	13.2	12.4	0.8	6.5%
Total Operating Expenses	*164.8*	*159.2*	*5.6*	*3.5%*	*159.2*	*159.8*	*(0.7)*	*(0.4%)*
Amortization of Assets	122.5	117.7	4.8	4.1%	117.7	122.0	(4.3)	(3.5%)
Total Distribution Expenses	**287.3**	**276.8**	**10.5**	**3.8%**	**276.8**	**281.8**	**(5.0)**	**(1.8%)**

2004 vs. 2003

1. Total distribution expenses in 2004 were $287.3 million, $10.5 million or 3.8 percent higher than in 2003. The increase was due to higher controllable expenses ($5.1 million or 3.5 percent), amortization of assets ($4.8 million or 4.1 percent) and higher taxes other than PILs ($0.6 million or 4.3 percent). The increase in amortization reflects higher balances for distribution assets, while the increase in taxes arose from an increase in municipal taxes and a favourable adjustment to provincial capital taxes in 2003.

2. Higher payroll costs were a significant contributor to the increase in controllable expenses, reflecting a 3 percent general increase in base pay and higher employer contributions to the OMERS pension plan. The $5.1 million increase in controllable expenses was primarily due to increased expenses for billing and collection ($3.4 million or 11.6

percent), operation ($2.4 million or 6.2 percent) and maintenance ($0.8 million or 3.6 percent), somewhat offset by lower administrative and general expenses ($1.7 million or 3.3 percent).

3. The increase in billing and collection expenses was mainly due to higher expenses for bad debt ($1.7 million) and for customer billing ($1.4 million). The increase in bad debt expense reflects a non-recurring credit reported in 2003, arising from a transmission metering error and related revisions to THESL's electricity revenue estimation model. The increase in customer billing expense reflects higher costs for payroll and postage.

4. The increase in operation expenses was mainly due to higher expenses for supervision and engineering and load dispatching, resulting from higher payroll costs, offset by lower miscellaneous distribution expenses and meter expenses, resulting from higher recovery of labour costs charged to capital projects. The increase in maintenance expenses reflects higher payroll costs.

5. The decrease in administrative and general expenses was mainly due to lower general and administrative salaries and expenses (non-recurring charges in 2003 relating to employee benefits), lower maintenance of general plant expenses (staff reductions in facilities and information technology) and an administrative expense transferred credit (higher management payroll costs allocated to capital projects in 2004). The decreases were somewhat offset by an unfavourable adjustment in 2004 to GST recovery claims.

2003 vs. 2002

6. Total distribution expenses in 2004 were $276.8 million, $5.0 million or 1.8 percent lower than in 2003. The decrease was due to lower amortization of assets ($4.3 million or 3.5 percent) and lower controllable expenses ($1.5 million or 1.0 percent), offset by higher taxes other than PILs ($0.8 million or 6.4 percent). The decrease in amortization reflects a non-recurring write-off in 2002 of non-qualifying transition costs of $7.0 million, offset by an increase of $2.6 million in depreciation of general plant and software assets due to the investment in distribution plant and implementation of an ERP software system. The increase in taxes arose from higher property value assessments and tax rates.

7. Higher payroll costs were a significant contributor to increases in certain controllable expenses, reflecting a 3 percent general increase in base pay. The $1.5 million overall decrease in controllable expenses was primarily due to lower expenses for operation ($4.0 million or 9.4 percent), billing and collection ($3.8 million or 11.4 percent) and community relations ($1.7 million or 41.4 percent), offset by higher administrative and general expenses ($5.7 million or 12.0 percent), and maintenance expenses ($2.3 million or 11.2 percent).

8. The decrease in operation expenses was mainly due to lower supervision and engineering, resulting from lower charges payable to THESL's Telecom affiliate for fibre rental and higher capitalization of payroll costs for control room operators. The decrease in billing and collection expenses was mainly due to lower bad debt expense, reflecting

exceptional provisions recorded in 2002, which were partially recovered in 2003. The decrease in community relations expense was attributable to the impact of a change in accounting policy for asset retirement obligations, as described later in this section.

9. The increase in administrative and general expenses was due to a non-recurring unfavourable adjustment related to employee benefits, a step increase in the liability for post-employment benefits resulting from a new collective bargaining agreement, an increase in the proportion of certain allocations to THESL for shared services (namely, facilities and information technology) that had been over-allocated to affiliates in 2002, a general increase in payroll costs, and credits recorded in 2002 to reverse prior year accruals.

10. The increase in maintenance expenses was mainly due to higher costs for station buildings and fixtures (contractor costs) and overhead services (increased labour and vehicle hours), offset by lower costs for meters (reduced maintenance activity). The increase in costs for underground conductors and devices was largely offset by decreases for overhead conductors and devices, reflecting a shift in maintenance program priorities.

Accounting Policy Change for Asset Retirement Obligations

11. Effective January 1, 2004, THESL adopted the new Canadian Institute of Chartered Accountants standard for accounting for asset retirement obligations ("ARO"). Under the new standard, THESL 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 amortized 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 ARO is incurred.

12. The effect of the adoption of the new standard was recorded retroactively with the restatement of the year ended December 31, 2003 and an adjustment to January 1, 2003 opening retained earnings. The impact of the adoption on THESL’s distribution expenses for the years ended December 31, 2003 and 2004 is provided in TABLE 6-1. (Also included is the impact on THESL’s distribution expenses for the year ended December 31, 2002, under THESL’s superceded environmental costs accounting policy).

TABLE 6-1

Distribution Expenses	OEB Account	Year Ended December 31		
		2002	2003	2004
Amortization of Assets	5705[1]	Not applicable ["N/A"]	$103,000	$121,000
Accretion Expense	5420[2]	N/A	$193,000	$235,000
Environmental Liability Provision Expense	5420	$1,618,000	N/A	N/A

13. Under THESL's superceded accounting policy, THESL would provide for future costs associated with the disposal of contaminated waste and site restoration for certain of its properties, by charges to income (i.e. distribution expenses).

Asset Retirement Obligation Liability

14. Reconciliation between the opening and closing ARO liability balances is provided below in Table 6-2:

TABLE 6-2

	2002	2003	2004
Balance January 1	N/A	$3,125,000	$4,040,000
ARO Liabilities Incurred in the Year	N/A	$1,233,000	$139,000
ARO Liabilities Settled in the Year	N/A	($511,000)	($140,000)
Accretion Expense	N/A	$193,000	$235,000
Balance December 31	N/A	$4,040,000	$4,274,000

[1] OEB account 5705 is "Amortization expense – Property, Plant and Equipment"
[2] OEB account 5420 is "Community Safety Program"

APPENDIX 6-B: 2005-06 DISTRIBUTION EXPENSES – BASIS OF PROJECTIONS

1. Projected Distribution Expenses were developed on the basis of 2004 results as previously reported to the OEB. Certain changes in presentation were made to align with the requirements of the EDR Model:
   (a) Provincial Capital Taxes were removed from Other Distribution Expenses and instead included within Income Taxes
   (b) Collection charges were removed as a credit to Billing & Collection expenses and instead included within revenue from Specific Service Charges
2. Unusual (non-recurring) items were excluded from the results to produce a 'normalized' view of 2004 expense levels, with a materiality threshold of $50,000 used for purposes of identifying unusual items. The adjustments were as follows:

Reversal of prior year accruals for goods or services	1,398,960
Employee termination costs	(2,487,752)
Employee life insurance premium adjustment	(150,000)
Fleet fuel & garage inventory adjustments	105,356
Capital tax adjustments allocated from parent company	(428,268)
Adjustment to allocated warehouse overhead	(1,619,279)
Writedown of OMERS disability deposit (reversed in '05)	(700,000)
Inventory adjustments	532,200
Adjustment to GST Recoveries	(3,035,071)
Transformer Rebate	73,909
TOTAL	**(6,309,945)**

3. No adjustments for CDM expenses were made as this spending was reported under a tracking account and not included in distribution expenses.

4. The following adjustments were then applied to produce projections for 2005 & 2006:

Amortization of Fixed Assets

5. In each year, amortization expenses were subject to: (a) decreases attributable to assets becoming fully depreciated in 2005 or 2006, and therefore no longer subject to further amortization expense; and (b) increases attributable to new capital investments (as described in section 4) expected in each of 2005 and 2006. The applicable Amortization Rates are described in section 4.1. The incremental amortization expense

relating to Smart Meters is based on 15 years for meter equipment and 5 years for information technology spending.

Other Distribution Expenses

6. Generally, all other projections for 2005-06 Distribution Expenses were held at the same level as the 2004 'normalized' results, with any exceptions described below.

Employee Compensation, Pensions and Benefits

7. All base pay, overtime and premiums are projected to increase by 3 percent in 2005 and by 3 percent in 2006. Pension costs are expected to increase by 3 percent in 2005 and by 12 percent in 2006, reflecting the anticipated increase in OMERS contribution rates. Accrual costs for post-employment benefits are expected to increase by 9 percent in 2005 and 4 percent in 2006 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.
8. These increases are somewhat offset by higher allocations of management payroll costs to capital projects (5 percent in 2005 and 12 percent in 2006), reflecting increases in annual capital investments.

Smart Meters

9. Incremental expenses for Smart Meters are as follows, based on the installation of 150,000 residential units and 7,500 commercial units by the end of 2006:

Expense Type	*Description*	*Amount*
Operation	157,500 units @ $12.36	$1,946,700
Billing & Collection	Customer notification costs	94,500
Community Relations	Public awareness campaign	250,000
TOTAL		**$2,291,200**

Regulatory Expenses

10. Regulatory expenses relating to the Ontario Energy Board and to the Electrical Safety Authority have been set to their 2006 expected levels.

Insurance Expenses

11. Specific projections for 2005-06 insurance costs are described in Schedule 6-1.

APPENDIX 6-C

Summary of 2002 - 2006 Advertising Expenses

Type of Expense	2002	2003	2004	2005	2006
Public Education	$54,693.37	$16,471.64	$160,395.22	$50,000.00	$400,000.00
Rate Information	$72,944.71	$83,566.95	$107,543.22	$25,000.00	
Conservation Programs (Residential/Small Commercial)				$1,406,980.82	$1,192,500.00
Conservation Awareness and Education				$584,030.22	$1,055,000.00
Conservation Programs (Commercial/Industrial)				$164,150.00	$65,000.00
Smart Meters/Load Control				$50,000.00	$90,000.00
Distributed Energy				$20,000.00	$40,000.00
Ebills and Pre-Authorized Payments (PAP)				$89,997.00	$60,000.00
Consumer Research				$29,923.00	$74,000.00
TOTAL:	**$127,638.08**	**$100,038.59**	**$267,938.44**	**$2,420,081.04**	**$2,976,500.00**

APPENDIX 6-D: BUSINESS EXPENDITURE REIMBURSEMENT POLICY

Toronto Hydro Corporation Policy Manual

Issue Date: January 2004

BUSINESS EXPENDITURE REIMBURSEMENT POLICY

Policy Statement

Toronto Hydro employees, whether permanent or contract, are occasionally required to incur expenses for and/or while conducting Toronto Hydro business. Reimbursement for such business expenses will be made for expenses actually incurred; however, it is the employee's responsibility to document such expenditures in accordance with the procedures in this Business Expenditures Reimbursement Policy (the "Policy").

Toronto Hydro will reimburse <u>reasonable</u> and <u>necessary</u> business-related expenses that are authorized by Toronto Hydro under this Policy ("Reimbursable Expenses"). It is expected that employees will exercise the same judgment and control in incurring Toronto Hydro business expenses that a prudent person would exercise if incurring expenses for personal reasons. Toronto Hydro's Business Expense Reimbursement Policy has been designed to provide flexibility wherever possible.

This Policy is intended to:

- Ensure clear and consistent understanding of policies and procedures.
- Provide guidelines that simplify business events arrangements and enable Toronto Hydro to manage its business expenditures.
- Ensure compliance with provincial, federal and regulatory agency requirements and laws.

Applicability

This Policy applies to all Toronto Hydro companies and affiliates, including, but not limited to Toronto Hydro Corporation, Toronto Hydro Electric System Ltd., Toronto Hydro Energy Services Inc., Toronto Hydro Telecom Inc., and Toronto Hydro Street Lighting Inc.

This Policy applies to Reimbursable Expenses whether "self-paying" or when using the Toronto Hydro Corporate Card ("Procard"). When the Procard is used, expense reporting forms and procedures, as described in this Policy, also apply to Procard payment. Specific policies and procedures for the Procard are described in Toronto Hydro Corporate Card Policy and Procedures.

Canada Customs and Revenue Agency ("CCRA") Requirements

Under CCRA regulation, all reimbursements for Reimbursable Expenses must meet these requirements:

- Reimbursements must be made for business expenses only and must be reasonably related to the expenses the employer is expected to incur.
- The employee must complete, within a reasonable time after the expenses incurred, an Expense Report substantiating the amount and business purpose.
- Receipts for expenditures must be attached to the Expense Report.

Conflict

If in any situation this Policy conflicts with, or is silent with regards to, relevant stipulations in the Collective Agreement between CUPE and Toronto Hydro dated February 1, 2003 to January 31, 2006, the terms and conditions of the Collective Agreement will apply.

Advances

Toronto Hydro does not provide cash, or any other monetary advances, of any kind.

Administration and Compliance

This Policy shall be administered and enforced uniformly for all employees.

i) Responsibilities of Approvers

Approvers are responsible for communicating and ensuring that the Policy is readily available to all employees, and for monitoring compliance with this Policy when authorizing Expense Reports.

An employee's Expense Report must be approved by the employee's supervisor (the "Approver"). Employees may not approve their own Expense Reports, nor those for an individual to whom they report, either directly or indirectly.

"Senior Person Rule": The Approver cannot have been a party to an expenditure on any Expense Report they approve. In any case where an employee's Approver is a party to the expenditure, the Approver is required to incur the expense and submit it on an Expense Report for reimbursement.

The Approver must verify that business expenses and Expense Reports meet the criteria of this Policy, including:

- the expense was incurred while conducting Toronto Hydro business,
- the information contained on the Expense Report, with receipts/statements is complete, accurate, and valid in accordance with this Policy, and
- the expenditures are identified in the appropriate section(s) of the Expense Report to ensure that they are recorded in the proper account(s).

Signature Delegation

Authority and responsibility for approval and control of expenditures by employees rests with the Approver. In certain circumstances, in the temporary absence of the employee's Approver, another approving authority may be designated moving up one level from the absent Approver, by indicating this delegation on the Expense Report.

ii) Responsibilities of Employees

Toronto Hydro employees are expected to spend Toronto Hydro funds prudently. Business expenses will be reimbursed by Toronto Hydro if they are reasonable, appropriately documented, properly authorized, and within the guidelines of this Policy. Employees who incur Reimbursable Expenses should neither gain nor lose personal funds as a result of incurring the Reimbursable Expenses.

Any questions regarding a situation that may not be specifically addressed in this Policy, or as to interpretation of this Policy, are to be directed to the Corporate Controller, Toronto Hydro Corporation. Toronto Hydro assumes no responsibility for reimbursing to employees any expense not clearly identified as a Reimbursable Expense in this Policy.

Reimbursable Expenses

A. Summary of Reimbursable Expenses

1. Business Meal Expenses
2. Entertainment
3. Personal Car Usage
4. Club Memberships
5. Professional Dues/Memberships
6. Conferences, Seminars and Training
7. Travel
    a) Air Travel
    b) Personal Meals while Traveling
    c) Lodging
    d) Ground Transportation

B. Detailed Descriptions of Reimbursable Expenses

1. BUSINESS MEAL EXPENSES

Business Meal expenses may include charges for meals as well as other direct costs of the meeting (e.g., room setup charges, wait staff, etc.) at which Toronto Hydro employees and their guests meet to talk about Toronto Hydro business. For purposes of reporting on the Expense Report form, Business Meal costs do not include entertainment or social activities or any costs directly linked to entertainment (such as tickets to shows or sporting events, lodging, transportation, or food or rental costs related to entertainment) – See 2. Entertainment, below.

THE NAME OF EACH GUEST, THEIR AFFILIATION, AND THE BUSINESS SUBJECT DISCUSSED DURING THE MEAL MUST BE DOCUMENTED ON THE EXPENSE REPORT.

2. ENTERTAINMENT

There are occasions when the entertainment of special visitors, speakers, prospective employees, customers or clients is appropriate and in Toronto Hydro's interest. Each supervisor is responsible for making sure that expenditures for this purpose are reasonable and appropriate for Toronto Hydro.

ENTERTAINMENT EXPENSES MUST BE DOCUMENTED BY A FULL DESCRIPTION OF THE BUSINESS SUBJECT DISCUSSED AT THE EVENT, ALONG WITH THE NAMES AND AFFILIATIONS OF ALL ATTENDEES.

3. PERSONAL CAR USAGE

Unless indicated herein or in another Toronto Hydro Policy, employees who use their personal automobile as part of their normal duties will be reimbursed for mileage. The mileage rate for reimbursement is $0.41 per kilometer.

Mileage for an employee's commute between his or her usual Toronto Hydro work site and home is not a Reimbursable Expense.

Employees will not be reimbursed for the following expenses related to personal automobiles, even if these costs are incurred while performing Toronto Hydro business:

- Car repairs (normal or as a result of an accident)
- Rental car costs during repair of personal car
- Tickets, fines, or traffic violations

In order to be reimbursed for mileage, the employee must complete a Mileage Log and attach it to an appropriately completed Expense Report.

4. CLUB MEMBERSHIPS

Individual dues for membership in any club organized for business, pleasure, recreation, or any other purpose are not reimbursable under this Policy.

5. PROFESSIONAL DUES/MEMBERSHIPS

Memberships in professional societies, organizations, or institutions that are a requirement of the employee's job or are contractually permitted and approved by their supervisor are Reimbursable Expenses and generally not taxable.

6. CONFERENCES, SEMINARS AND TRAINING

Employees are encouraged to attend conferences, seminars and training that are a requirement or enhancement to the employee's job. All such expenditures permitted and approved by their supervisor are Reimbursable Expenses and generally not taxable.

7. TRAVEL

"Travel" for the purposes of this Policy is any business-related event requiring an employee to be away from any Toronto Hydro facility, or any field work site in the 416 and 905 area code geography, for more than seven continuous hours.

a) AIR TRAVEL

All air travel expenditures need prior approval by a VP or executive.

b) PERSONAL MEALS WHILE TRAVELING

For reimbursements of personal meals while traveling on Toronto Hydro business, Employees must submit receipts from meals and will be reimbursed for the actual costs incurred. Actual meal costs are expected to be reasonable and for the employee only. When more than one Toronto Hydro employee is present, all names of other employees should be noted on the Expense Report.

If the meal includes non-employees, the Policy regarding Business Meal Expenses, above, applies.

c) LODGING

Toronto Hydro will reimburse employees for "standard" accommodations at hotels. When required, accommodation the night prior to the first program event for a conference, seminar, workshop and the night immediately following the program close are eligible for reimbursement.

The original receipt or statement must be attached to the Expense Report.

Lodging expenditures must be itemized by day and expense category on the Expense Report, and must be attached to the Expense Report. For example, meals, tips, room service, parking, laundry, and telephone calls are to be included on the Expense Report in the appropriate categories.

d) GROUND TRANSPORTATION

Car Rentals

Automobile rentals should be limited to situations where other means of transportation are not practical, economical, or available. The most economical car should be used.

The original receipt or statement must be attached to the Expense Report.

Expense Reporting

Timing for Expense Report Completion and Submission

Toronto Hydro requires employees to submit a completed, approved Expense Report to Accounts Payable on a timely basis.

Procard holders should report both Procard payment and self-payment on the same Expense Report.

Signature

<u>Employee’s signature:</u>

- The employee must sign and date the Expense Report form; Assistants may not sign on their Manager’s/Supervisor’s behalf.

- Signing or initialing another person's name is not allowed.

By signing the Expense Report form, the employee certifies that the expenses claimed on the Expense Report are Reimbursable Expenses made in accordance with this Policy.

Business Purpose

The following must be identified on an Expense Report:

- The business reason for expenses, or nature of the business benefit derived as a result of expenditure

Receipts and Documentation

Toronto Hydro requires employees to submit the following documentation to substantiate expenses on their Expense Report form:

- For each individual expenditure, receipts must be attached,.
- Taxi – all taxi receipts.
- Personal Car Usage – receipts for all tolls and parking, and the Mileage Log.
- Business Meals/Entertainment – credit card slip (if applicable), or cash register receipt.

All receipts must include the name of the vendor, location, date, and dollar amount. For expenditures incurred in Canada, if Goods and Services Tax (“GST”) has been included in the expense, specific identification of the GST amount and the supplier’s GST registration number should be included in the receipts.

Missing Receipts

- Any otherwise Reimbursable Expense requiring a receipt as noted in this Policy that does not have the required receipt attached to the Expense Report will not be reimbursed.

Rationale

A consistent approach is needed for Toronto Hydro employees to recover expenses incurred while carrying out Toronto Hydro business.

APPENDIX 6-E: COLLECTIVE AGREEMENT BETWEEN TORONTO HYDRO AND CUPE LOCAL NO. 1

COLLECTIVE AGREEMENT

BETWEEN

TORONTO HYDRO

AND

LOCAL NO. 1
CANADIAN UNION OF
PUBLIC EMPLOYEES

(Representing Inside Employees)

FEBRUARY 1, 2003

TO

JANUARY 31, 2006

(b) When called out four (4) hours or more before her/his scheduled shift, is paid at double time until released.

33.27 Time worked on scheduled off-days is paid at double time.

Public Holiday

33.28 Hours worked by shift employees on regular shift on an observed Public Holiday are paid at double time and receive a day in lieu unless Public Holidays have been provided for in the shift schedule.

33.29 Shift and Non-Shift employees shall have the option of being paid overtime worked at the premium rates, as provided in the overtime provisions of the Agreement, or being paid at straight-time for the overtime hours worked and accumulating lieu time hours, equivalent to the actual hours worked, to a maximum of forty (40) hours where the term of the Agreement is one (1) year and eighty (80) hours where the term of the Agreement is two (2) years. Lieu time must be taken on a full day basis, and within the term of the Agreement.

33.30 When accumulated lieu time is not taken, the employee shall be reimbursed at the end of the term of the Agreement in an amount equivalent to accumulated lieu time not taken. Payment shall be at the employee's current rate of pay in effect at the end of the term of Agreement.

Travel Time

33.31 Travel time to and from duty report points designated by the Employer is not allowed except as follows:

(a) Employee called out for immediate report shall be paid from time of call, plus a half (1/2) hour at double time to return home, except payment for returning home does not apply when the work terminates at normal stopping time. Responsibility for infringement of travel time rests with the Supervisor.

(b) Employee working in area not served by the Employer reports at area limits not earlier than 8:00 a.m. and ceases work at area limits not later than 5:00 p.m.

(c) One half (1/2) hour at double time allowance to and from employee's home on prearranged overtime or when reported for duty and instructed to return at a time later in the day. This shall not apply when the prearranged overtime results in an extension or early commencement of a regular work day/shift.

N.B. Transportation is supplied within the City of Toronto to and from work, during such hours after Midnight as convenient public transportation is unavailable.

The above shall not apply to employees residing outside the boundaries of City of Toronto. These employees shall be paid travel time of one half (1/2) hour at double time when called out for immediate report and one half (1/2) hour to return home. Payment for returning home does not apply when the work terminates at normal stopping time.

Meal Allowance

Effective February 1, 2003 the meal allowance shall be \$11.00. Effective February 1, 2004 the meal allowance shall be \$11.50. Effective February 1, 2005 the meal allowance shall be \$12.00.

33.32 Meal allowance is provided as follows:

(a) Employee continuing working past her/his regular stop time, circumstances permitting, shall eat her/his first meal at normal stop time and at intervals thereafter of four (4) hours. Meals shall be calculated from normal stop time. Employee must work two (2) hours past her/his last meal period to be paid for same.

(b) Employee called back for emergency work three (3) hours or more and at intervals thereafter of not less than four (4) hours until released.

(c) Employee working prearranged overtime on her/his off days more than eight (8) hours and at intervals thereafter of not less than four (4) hours until released.

(d) There shall be no loss of time when meals provided above are taken. It is understood that responsibility for length of meal time rests with the Supervisor.

Mileage Allowance

33.33 The Employer shall provide employees who are authorized to use their own automobile on Employer's business up to $300.00 per contract year to cover the difference in insurance premium cost between pleasure and business driving. Employees are required to maintain a minimum of $1,000,000 Public Liability and Property Damage Coverage.

Employees shall be reimbursed 41 cents per kilometer for all kilometers travelled while on Employer's business. Conversion factor is 1 mile = 1.6 kilometers.

The rate paid per kilometer is related to changes in the Private Transportation Index (P.T.I.) component of the Consumer Price Index of Canada (1992 = 100). The P.T.I. base figure is 125.5 points (January 31, 1999) and for each 11.9 points increase an additional one (1) cent per kilometer shall be paid. The effective date for changes in rate paid will be the first of the month following the month in which the index is published.

Break Periods

33.34 Two fifteen (15) minutes break periods will be allowed all employees each regular working day. For shift employees whose normal work day is more than eight (8) hours an additional break period of fifteen (15) minutes will be allowed. These periods will be arranged in such a way as to prevent inconvenience to the customers or disruption of work.

Parking and Telephone Charges

33.35 The Employer shall refund the cost of public pay telephone calls while on Employer's business.

The Employer shall refund the cost of parking meter or

COLLECTIVE AGREEMENT

BETWEEN

TORONTO HYDRO

AND

LOCAL NO. 1
CANADIAN UNION OF
PUBLIC EMPLOYEES

(Representing Outside Employees)

FEBRUARY 1, 2003

TO

JANUARY 31, 2006

33.30 When accumulated lieu time is not taken, the employee shall be reimbursed at the end of the term of the Agreement in an amount equivalent to accumulated lieu time not taken. Payment shall be at the employee's current rate of pay in effect at the end of the term of Agreement.

Travel Time

33.31 Travel time to and from duty report points designated by the Employer is not allowed except as follows:

(a) Employee called out for immediate report shall be paid from time of call, plus a half (1/2) hour at double time to return home, except payment for returning home does not apply when the work terminates at normal stopping time. Responsibility for infringement of travel time rests with the Certified Crew Leader/Employer.

(b) Employee working in area not served by the Employer reports at area limits not earlier than 8:00 a.m. and ceases work at area limits not later than 5:00 p.m.

(c) One half (1/2) hour at double time allowance to and from employee's home on prearranged overtime or when reported for duty and instructed to return at a time later in the day. This shall not apply when the prearranged overtime results in an extension or early commencement of a regular work day/shift.

N.B. Transportation is supplied within the City of Toronto to and from work, during such hours after Midnight as convenient public transportation is unavailable.

The above shall not apply to employees residing outside the boundaries of City of Toronto. These employees shall be paid travel time of one half (1/2) hour at double time when called out for immediate report and one half (1/2) hour to return home. Payment for returning home does not apply when the work terminates at normal stopping time.

Meal Allowance

Effective February 1, 2003 the meal allowance shall be $11.00. Effective February 1, 2004 the meal allowance shall be $11.50. Effective February 1, 2005 the meal allowance shall be $12.00.

33.32 Meal allowance is provided as follows:

(a) Employee continuing working past her/his regular stop time, circumstances permitting, shall eat her/his first meal at normal stop time and at intervals thereafter of four (4) hours. Meals shall be calculated from normal stop time. Employee must work two (2) hours past her/his last meal period to be paid for same.

(b) Employee called back for emergency work three (3) hours or more and at intervals thereafter of not less than four (4) hours until released.

(c) Employee working prearranged overtime on her/his off days more than eight (8) hours and at intervals thereafter of not less than four (4) hours until released.

(d) There shall be no loss of time when meals provided above are taken. It is understood that responsibility for length of meal time rests with the Certified Crew Leader/Employer.

Mileage Allowance

33.33 The Employer shall provide employees who are authorized to use their own automobile on Employer's business up to $300.00 per contract year to cover the difference in insurance premium cost between pleasure and business driving. Employees are required to maintain a minimum of $1,000,000 Public Liability and Property Damage Coverage.

Employees shall be reimbursed 41 cents per kilometre for all kilometres travelled while on Employer's business. Conversion factor is 1 mile = 1.6 kilometres.

APPENDIX 6-F: COLLECTIVE AGREEMENT BETWEEN THESL AND THE SOCIETY OF ENERGY PROFESSIONALS

COLLECTIVE AGREEMENT

Between:

THE TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

"The Employer"

-and-

THE SOCIETY OF ENERGY PROFESSIONALS

"The Society"

JULY 1, 2003

to

JUNE 30, 2006

ARTICLE 28

SAFETY EQUIPMENT AND SAFETY SHOES

28.1 The Employer will supply the necessary safety equipment including safety shoes and work clothing to protect employees, at no cost to the employee. Employees will receive such equipment that is necessary in the normal performance of their duties.

ARTICLE 29

MEAL ALLOWANCE

29.1 Effective July 1, 2003 the meal allowance shall be $11.00. Effective July 1, 2004 the meal allowance shall be $11.50. Effective July 1, 2005 the meal allowance shall be $12.00.

a) Employee continuing working past her/his normal stop time on authorized overtime, circumstances permitting, shall eat her/his first meal at normal stop time and at intervals thereafter of four (4) hours. Meals shall be calculated from normal stop time. The employee must work two (2) hours past her/his last meal period to be paid for same.

b) Employee called back for emergency work of three (3) hours or more and at intervals thereafter of not less than four (4) hours until released.

2005 Performance Pay Guidelines

The Introduction

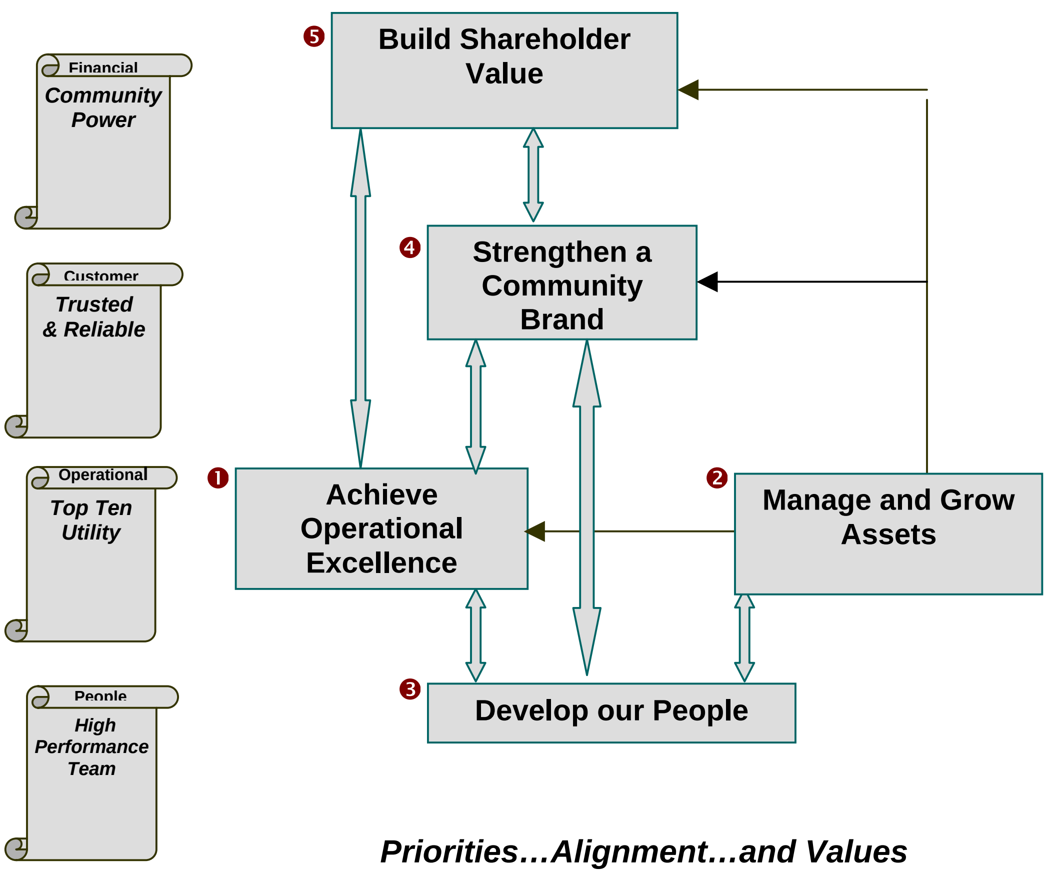
The Performance Pay Program reinforces Toronto Hydro's commitment to recognize and reward employee performance and contributions. The objectives of the program are to:

- Recognize employees for achievement of individual stretch goals, business unit and corporate performance, beyond normal job functions
- Support the organization's vision, goals and change strategies
- Keep Toronto Hydro's total compensation package competitive

The performance pay guidelines outline the following information:

- 2005 Strategic Map
- 2005 Priorities
- Performance Pay calculation details
- 2005 Corporate and Organizational Scorecards

2005 Strategic Map



Priorities…Alignment…and Values

2005 Performance Pay Guidelines

- Strategy can be thought of as a co-ordinated set of activities designed to deliver comparatively superior performance. This definition reflects our Top 10 behaviours since co-ordination requires *communication* and *collaboration.* Delivery of superior performance requires *result orientation, accountability* and *leadership*.
- Our vision is to be Top 10 in safety, service, reliability, cost and training
- The executive team has established specific targets for each of these and identified priorities within our strategic map that need to be addressed for 2005.

2005 Priorities

The following are our corporate priorities for this year:

- Safety System	**- Leadership Development**
- Work Practices	**- Conservation & Demand Side Management**
- Material Scheduling	**- Collaborative Union Management Relations**
- Outage Management	**- Trades Development**

The 2005 Priorities
- Makes a measurable difference to one or more of the Top 10 measures
- Addresses one or more of the strategic priorities
- Usually involves significant investment of resources (people, funding etc)
- Often involves multiple stakeholders or business units
- Usually involves significant process change

There will be some initiative proposals that are exceptions to the above. If they don't move us toward Top 10 at least indirectly, involve significant change or involve major resource investment, they would not be specifically identified in our business plan. However, they may still be excellent ideas that should proceed as departmental initiatives.

It is important to know and communicate to staff that all of our current activities are part of the strategic map and essential. If the Control Room, Call Centre, Payroll or any of dozens of other departments don't perform effectively it will have a major impact on the strategic performance of this organization. But many

2005 Performance Pay Guidelines

departments will not significantly change how they operate next year. Not being part of a 2005 priority does not mean that a group is not an essential part of the strategic map.

Eligibility

The program is effective January 1st, 2005 and all management employees and professional engineers (The Society of Professional Engineers) of Toronto Hydro Corporation and Toronto Hydro Electric System (THESL) are eligible for the Performance Pay Program.

The program combines both individual/business unit performance and corporate performance. Payouts differ by job level. The program is revisited on an annual basis, and may be modified, at the discretion of the Executive.

The following table allocates the weightings by position for 2005. THESL individual contracts include business unit targets, as well as individual.

Position	Individual Performance (%)	Business Unit Performance (%)	Corporate Performance (%)
CEO, CFO - THC	25		75
CEO - THESL	25	50	25
Executives- THC	40		60
Executives - THESL	40	40	20
Managers - THC	60		40
Managers - THESL	60	30	10
Supervisors and Professionals - THC	80		20
Supervisors and Professionals - THESL	80	15	5
Service and Administration - THC	90		10
Service and Administration - THESL	90	5	5

How are payouts calculated?

For THC, the program is based on both operational results in your performance contract and corporate performance from the Corporate Scorecard, and follows a

2005 Performance Pay Guidelines

split calculation as per the above table, depending on job level. Below is a sample of the payout formula:

- Salary for THC employee = $70,000
- 6% eligibility for performance pay = $4,200
- % of weightings for THC employee = 80% individual performance and 20% corporate performance

Performance Contract (Individual performance)	$3,360
Corporate Scorecard (Corporate performance)	$840

If 80% of the Performance Contract is achieved and 70% of the Corporate Scorecard is achieved, than the payout would be calculated as follows:

Performance Contract ($3,360 x 80%)	$2,688
Corporate Plan (840 x 70%)	$588
Total Payout	**$3,276**

For THESL, the program is based on both operational results in your performance contract, organization (THESL) and corporate performance from the Corporate Scorecard, and follows a split calculation as per the above table, depending on job level. Below is a sample of the payout formula:

- Salary for THESL employee = $70,000
- 6% eligibility for performance pay = $4,200
- % of weightings for THESL employee = 80% individual performance and 15% business unit, and 5% corporate performance

Performance Contract (Individual performance)	$3,360
Business Unit (Company)	$630
Corporate Scorecard (Corporate performance)	$210

If 80% of the Performance Contract is achieved and 90% of the Business Unit Scorecard and 70% of the Corporate Scorecard is achieved, than the payout would be calculated as follows:

2005 Performance Pay Guidelines

Performance Contract ($3,360 x 80%)	$2,688
Business Unit (Company) ($630x90%)	$567
Corporate Plan (210 x 70%)	$147
Total Payout	**$3,402**

Worth Mentioning: Your leader may use discretionary ranking to assess the attainment of your individual/business unit objectives.

2005 Performance Pay Guidelines

Scorecards 2005

Following are the THC Scorecard and THESL Scorecard. The KPI's provide important organizational measures and targets that will focus our performance discussions. The scorecard will be the framework used to report overall performance under the categories of People, Finance, Operations and Customer. *Note that Training, Engagement and Communication are important goals. The targets are recognized in individual and business unit performance objectives, and leadership development.*

THC 2005 Scorecard

KPIs	Target	Weight
People		
Safety - injury frequency *injuries per 100 staff*	**0.5**	**7.5%**
Safety - injury severity *days lost per 100 staff*	**8**	**7.5%**
Engagement & Communication *support for TH direction*	**80%**	**0%**
Training *days per person*	**5.0**	**0%**
Finance		
Operating Expense *$ millions*	**$184.4**	**15%**
Capital Expense *$ millions*	**$136.3**	**5%**
Financial Commitments (composite) *meeting financial targets*	**100%**	**20%**
Operations		
Capital Program *percent of work units completed*	**100%**	**10%**
Conservation Demand Management *percent attainment of 2005 component*	**100%**	**5%**
LDC Outage Duration (SAIDI) *minutes per customer*	**70**	**10%**
Customer		
LDC Service Levels (composite) *(12 measures) percent of targets met each month*	**95%**	**15%**
Affiliates Service Levels (composite) *percent of targets met each month*	**95%**	**5%**

THESL 2005 Scorecard

KPIs	Target	Weight
People		
Safety - injury frequency *injuries per 100 staff*	**0.5**	**7.5%**
Safety - injury severity *days lost per 100 staff*	**8**	**7.5%**
Engagement & Communication *support for TH direction*	**80%**	**0%**
Training *days per person*	**5.0**	**0%**
Finance		
Operating Expense *$ millions*	**$163.5**	**10%**
Capital Expense *$ millions*	**$124.4**	**15%**
Revenue/Other Income *$ millions*	**$18.9**	**15%**
Days Sales Outstanding *$ millions*	**21**	**5%**
Operations		
Capital Program Completion *percent of work units completed*	**100%**	**5%**
Workforce Utilization *percent of utilization*	**65%**	**5%**
Total Outage Duration (SAIDI) *minutes per customer*	**70**	**15%**
Support Asset Utilization *Average measure of cover up equipment, fleet and space asset utilization*	**76%**	**5%**
Customer		
Regulated Service levels *(12 measures) percent of targets met each month*	**95%**	**5%**
Call Centre Service Index *speed and quality of response*	**80%**	**5%**
Support Services Index *Aggregate measure of BSS service delivery measures*	**85%**	**0%**

CHAPTER 7 – TAXES / PILs

7.0 Introduction

1. The rates in this Application reflect an amount for PILs recovery of $47,634,254. This amount is based on the projected results used for the FTY in the OEB 2006 EDR Model. THESL has employed the 2006 OEB Tax Model with some adjustments to compute PILs amounts for the FTY. The basic computations, methodology, principles and detail of the 2006 OEB Tax Model have been followed.

7.1 General Methodology Underlying the 2006 Tax Calculation

7.1.1 Prudent Management of PILs/Taxes

2. 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 taxes 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.

7.1.2 Regulatory Taxes Expense Methodology

3. The tax amount calculated by THESL for inclusion in rates effective May 1, 2006 represents taxes payable for the distribution-only business.

The regulatory taxes computed are based upon the principles set out in Chapter 7 of the DRH.

7.1.3 Variations from the 2006 OEB Tax Model for FTY

4. As THESL is filing on an 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 2006. Only material adjustments have been included.
- Capital cost allowance is computed based on an estimated 2006 Schedule 8. Projected capital additions for 2006 are used. A separate computation of 2005 capital cost allowance is performed to derive 2006 Schedule 8 opening balances that reflect projected 2005 capital additions. Maximum capital cost allowance is taken for 2005. Projected 2005 capital additions and disposals and 2005 Schedule 8 are included in their respective tabs in the 2006 Tax Model.
- The cumulative eligible capital deduction is based on the computation of the 2006 amount. A separate Schedule 10 is also provided for the 2005 year for continuity purposes [2005 Schedule 10 CEC]. Maximum cumulative eligible capital deduction is taken for 2005.
- Schedule 1 adjustments:
  - For 2006, Schedule 1 adjustments are made only for material items that can be reasonably expected to be incurred in the test year. For instance, no add back is made for non-deductible meals and entertainment. Historically this amount has been

small relative to taxable income. As well, no non-taxable imputed interest income on deferral and variance accounts is expected in 2006.

- Material changes in reserves are not expected in the test year except for accrued employee future benefits. This reserve is included on Schedule 13 of the tax model.

7.1.4 Disclosure of PILs Tax Administration and Tax Rulings

5. THESL has not received any specific tax rulings or assessment policy that is inconsistent with the 2006 OEB Tax Model.

7.1.5 Tax Re-assessments

6. The Ministry of Finance has not yet reviewed any of the THESL tax returns for prior tax years. Therefore, the 2006 PILs amount computed for inclusion in the 2006 EDR does not contain any adjustments resulting from a reassessment of PILs of a previous year.

7.2 Principles Applicable to Specific Components of the Calculation

7. THESL has followed the 2006 OEB Tax Model to calculate PILs.

7.2.0 Tax Treatment of Dividends Paid in Prior Years

8. Dividends were paid in the preceding 3 years. The dividends were treated as payments out of tax paid retained earnings and therefore were not treated as deductible for tax purposes.

7.2.1 Non-recoverable and Disallowed Expenses

9. There are no non-recoverable expenses reflected in the 2006 EDR Model. Hence, no adjustment is required in respect of non-recoverable expenses for the 2006 regulatory tax calculation.

7.2.2 Capital Tax Exemptions

10. As THESL is the only regulated entity in the related corporate group, the federal large corporation tax and Ontario capital tax computations take into account the full LCT and Ontario capital tax exemptions available.

11. Computations of the Ontario capital tax and federal large corporations tax are made based on projected 2006 balance sheet amounts. For comparison purposes, a computation of the Ontario capital tax and federal large corporations tax based on the applied-for 2006 rate base is also presented. The greater of the two methods is used as the tax input in the 2006 EDR Model revenue requirement calculation.

7.2.3 Loss Carry-forwards

12. THESL has no non-capital or capital loss carry-forwards at the end of December 2004, and does not expect to have such loss carry-forwards at the end of December 2005.

13. THESL's only business within its legal entity is a distribution business. Accordingly, Schedule 7-1 of the DRH, Sharing Loss Carry-Forwards, is neither applicable nor included as part of this Application.

7.2.4 Undepreciated Capital Cost ("UCC") and Capital Cost Allowance ("CCA")

14. As THESL is filing this Application using an FTY, CCA is computed for 2006 based on projections of the change in capital assets over the 2005 and 2006 years. A separate Schedule 8 is prepared to compute CCA for 2005 and to derive the projected undepreciated capital cost balances at January 1, 2006. In doing this, maximum CCA is claimed in 2005. Maximum CCA is also claimed in the 2006 PILs tax model. As well, any additions projected for 2005 and 2006 are subjected to the half-year rule. The effects of the 2001 fair market value "bump" are reflected in the 2005 and 2006 CCA computations.

15. Attached is Schedule 7-2: October 2001 FMV Adjustment, that provides information relating to the fair market value "bump". Also Attached is a supplementary schedule to Schedule 7-2 that provides information on the remaining dollar value of the increase or decrease of the "bump" at December 31, 2004 and December 31, 2006.
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.

7.2.5 Regulatory Tax Treatment of Eligible Capital Expenditure ("ECE")

16. 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 2006 balance of cumulative eligible

property. A separate completed Schedule 10 for the 2005 year is used to derive the 2006 opening balance of cumulative eligible capital. Maximum cumulative eligible capital deduction is claimed for 2005 and 2006.

16. The cumulative eligible capital used in the computation includes the October 1, 2001 fair market value "bump".
17. Schedule 7-2 provides details of the fair market value "bump" for undepreciated capital cost and eligible capital property.

7.2.6 Interest Deduction

18. Actual interest expense is less than the deemed interest expense calculated by the 2006 EDR Model so no additional interest expense is deducted in the calculation of PILs in the 2006 OEB Tax Model.

7.2.7 Capitalized Interest

19. No amount of interest is elected to be capitalized to construction work in progress for tax purposes. No amount of interest is capitalized for accounting purposes in the 2004 or 2006 projections.
20. Attached is a completed Schedule 7-3: Interest Expense, that details the derivation of relevant interest calculations.

7.2.11 Non-distribution Elimination

21. THESL's business is solely the distribution of electricity and thus there are no adjustments to arrive at wires only figures.

7.2.12 Tax Credits

22. Estimated 2004 investment tax credits arising out of expenditures on qualifying Scientific Research and Experimental Development projects carried on by THESL equal approximately $200,000. This represents estimated qualifying expenditures (after including a proxy for overhead) of $1,000,000 at an investment tax credit rate of 20%. Expenditures before overhead proxy are estimated at approximately $610,000. THESL expects a similar level of expenditures to qualify for research and development tax credits in 2005 and 2006. No Schedule 1 adjustment is made to reflect 2005 investment tax credits claimed. There is an offsetting adjustment of a similar amount that is recorded in income for accounting purposes. The expected benefit is also below the $500,000 materiality threshold.

7.2.15 Capital Leases

23. No capital leases capitalized for accounting purposes are deducted for tax purposes.

7.3 Tax Payable Filings

7.3.1 Information to be Provided with 2006 OEB Tax Model Filings

24. The taxes paid by THESL in 2002, 2003, and 2004 were $10,521,656, 34,823,911 and 45,027,811 respectfully. Details are provided on the Test Year's PILs variance sheet within the PILS model.

25. The variance between taxes actually paid for 2004 and the 2006 test year grossed up amounts is very small, and much less than 25% of 2004 taxes. Therefore, a description of such variances is not required.

7.3.3 Supporting Documentation

26. Supporting schedules are included as part of the rate filing as are any supporting information requested in the filing instructions to the tax model.

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		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

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
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-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		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

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
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-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		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

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
	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
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

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
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**

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact:
Phone Number:

Calculated Deemed 2004 Interest Expense in 2006 EDR model	80,765,877	
2004 Actual Interest Expense	81,607,659	2-2 UNADJUSTED ACCOUNTING DATA L 491
2004 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA L 431
2004 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA L 432
2004 Actual Interest	81,607,659	
Interest Forecast for Tier 1 or 2 Adjustments		
Total Interest	81,607,659	
Excess Interest Expense for 2006 PILs	841,782	

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2004 and prior years.

CHAPTER 8 – REVENUE REQUIREMENT

8.0 Introduction

1. In this Application, THESL follows and conforms to the guidelines and spreadsheet models issued by the Board for deriving the service revenue requirement, base revenue requirement, and base revenue requirements for CDM, smart meters and regulatory asset recovery. THESL is confident that, because of the rigour applied in calculating the service revenue requirement and base revenue requirement, there has been no double recovery of any cost elements in rates, regulated charges and other incidental sources of revenue. Attached is Schedule 8-1: Derivation of Base Revenue Requirement.

8.1 Service Revenue Requirement

2. Projected 2006 distribution expenses are developed based on 2004 results previously reported to the Board. CDM spending and unusual (non-recurring) items were then excluded from the results to produce a "normalized" view of 2004 expense levels. In this regard, a materiality threshold of $50,000 was used for purposes of identifying significant or "material" unusual items. The resulting adjustments were then applied to the 2004 data to produce projections for 2005 and 2006 rate base, cost of capital, distribution expenses, and PILs amounts in order to derive the 2006 service revenue requirement.

8.2 Service Revenue Requirement and Base Revenue Requirement

Revenue Offsets

3. Since THESL is collecting revenues from sources other than distribution charges, these other revenue sources must be removed from the service revenue requirement. In keeping with the methodology for projecting distribution expenses for 2006, in general, revenue offsets have been developed by projecting these revenue streams on the basis of 2004 results. Unusual (non-recurring) items are excluded from the results to produce a "normalized" view of the 2004 level of revenue offsets. The resulting adjustments are then applied to produce projections for 2005 and 2006.

4. THESL is projecting a significant increase of $3.7 million in specific service charges because it is adopting the Board's standard levies for these services, and these levies are, in some cases, significantly higher than THESL's current charges. THESL notes that existing charges for certain specific services have not been adjusted for many years and so customers using some of these services currently face only nominal charges.

5. It is THESL's view that, by adopting the Board's standard amounts for these services, the subsidization of these services by other energy consumers will be reduced if not eliminated. The following are the major sources of Other Revenues:

A. Revenue from Late Payment Charges and Specific Service Charges

Late Payment Charges: Revenue from Late Payment Charges has averaged approximately $4.6 million per year. THESL expects this trend to continue.

Pole Attachment Charges: Pole attachment is considered to be a Specific Service Charge. This service generated approximately $1.3 million in 2004. By applying the pole attachment rate that has recently been approved by the Board, this category is estimated to contribute approximately $1.4 million to non-distribution revenue in 2006.

B. Revenue from Other Board-Approved Charges

RPP Administration Charges and Retail Service Charges are projected to remain at the 2004 level of $3.4 million.

C. Revenue from Sources Other than Board-Approved Rates and Charges

This revenue results mainly from facilities or property rentals. Duct space rentals generated more than $7.4 million in 2004. THESL is revising its duct bank rental rate to align with the methodology recently adopted by the Board in setting pole attachment rental fees. This change is projected to decrease this revenue stream to approximately $4.8 million in 2006.

6. Revenue from merchandise and jobbing generated $14.9 million in 2004, but was offset by $8.6 million in costs and expenses, yielding a net profit of $6.3 million. THESL submits, however, that close to $7.0 million of the 2004 revenue stream is non-recurring in nature since most of this revenue stream relates to a "true-down" of the Allowance for Doubtful

Accounts provision, the sale of scrap metals inventory or substation disposals. THESL projects 2006 revenue from merchandise and jobbing to be approximately $8.9 million and offset by $8.6 million costs, thereby providing a net revenue offset of only $0.3 million in 2006. This amount is reflected as part of investment income/deductions in the attached Schedule 8-2: Revenue from Sources Other Than Board-Approved Rates and Charges.

7. 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. As shown in Schedule 8-2, for 2006, THESL expects to earn approximately $3 million from investing idle cash balances.

Base Revenue Requirement

8. Following the derivation of the service revenue requirement, a detailed forecast of revenue from all applicable specific service charges and late payment charges, other Board-approved charges, and revenue from

sources other than Board-approved rates and charges was carried out to derive the 2006 base revenue requirement. Details of these revenue elements are provided in Schedules 8-1 and 8-2.

Revenue Re-Class

9. THESL notes that, in some instances, it records revenues into the various USoA based on its interpretation of the APH.
10. Class revenue from the sale of electricity comprising distribution revenues and cost of power revenues is recorded in the USoA 4006-4050. The account description for Commercial Energy Sales states, "these accounts shall include all revenue resulting from the sale of electrical energy used by customers classified as commercial". THESL believes that this implies that total revenue, including distribution and cost of power revenues, is booked here and by extension, the distribution revenue is not booked into another account. Nevertheless, after considering the provisions in the 2006 EDR Model, it is now apparent that USoA 4080 includes "distribution services" revenues comprising customer charges, volumetric distribution charges, SSS Administration Charges and Wheeling Charges.
11. THESL wishes to inform the Board that it did report the distribution revenues by class of customers, along with the number of customers, kWh and kVA, in its PBR filing. The PBR filing for 2002, 2003 and 2004 is presented in this Application as Appendix 8-A.

12. As THESL's current classification of distribution revenue has no impact on base revenue requirement determination, THESL makes no adjustments to the sale of electricity and distribution revenue accounts.
13. Where the determination of revenue offsets and base revenue requirement is impacted, THESL makes the appropriate adjustments in accordance with the instructions to the 2006 EDR Model. These adjustments are summarized in Appendix 8-B and are discussed below.
14. Since the EDR model does not include USoA 4080 (Distribution Services Revenue) in the Other Revenue category, RPP Administration Charges have been transferred from USoA 4080 (Distribution Service Revenue) to USoA 4090 (Electric Service Incidental to Energy Sales). Fixed and variable retailer charges are transferred from USoA 4080 to USoA 4082 (Retail Services Revenue).
15. All items not expressly defined as Specific Service Charges, but which are now included in USoA 4235 (Miscellaneous Service Revenue), have been transferred to USoA 4215 (Other Utility Operating Income). This has allowed USoA 4235 to include only the revenues calculated for the Specific Service Charges included in Schedule 11-3.
16. Pole attachment charges have been transferred from USoA 4210 (Rental from Electric Properties) to USoA 4230 (Sale of Water and Water Power). As pole attachment charges will be included in the Specific Service Charges calculation, to avoid double counting, THESL has placed this amount in USoA 4230, as recommended by the Board in its instructions for the 2006 EDR Model.

17. Collection charges are currently classified as a negative expense in USoA 5330 (Collection Charges) under the billing and collections expense category per the Board's APH. Since collection charges are included in the Specific Service Charges calculations, THESL finds it necessary to transfer the Collection Charges from USoA 5330 to USoA 4235 (Miscellaneous Service Revenue).

8.3 Revenue Requirements for CDM, Smart Meter and Regulatory Asset Recovery

CDM

18. In this Application for rates effective May 1, 2006, THESL is not seeking approval for any CDM spending that is incremental to funding previously approved by the Board.

Smart Meters

19. To comply with the Province's ambitious plan for smart meter implementation, for this Application for rates effective May 1, 2006, THESL is seeking approval for $52 million in additional capital and $2 million in additional operational expenses related to smart meters. THESL described its smart meter implementation plan in Chapter 4 of this Application.

Regulatory Asset Recovery

20. In 2005, THESL implemented rate riders to recover the regulatory assets account balance as at December 31, 2003 as per OEB Decision in RP-2004-0100. A final Order in this case was issued on July 26, 2005. These rate riders are separate and distinct from the regular volumetric distribution rate components and are effective for three years from April 1, 2005 to March 31, 2008. Rate rider revenue is not part of determined revenue requirement in this application. The values of the approved rate riders are shown in Schedule 8-3: Regulatory Asset Recovery.

_Incremental Rate Riders

21. As part of this Application, THESL is seeking to recover a number of sizeable, but one-time cost elements over a 23-month period beginning on May 1, 2006, as increments to existing Board-approved rate riders. These new cost elements are made up of incremental RSVA balances (calculations detailed in Appendix 8-C), incremental OEB fees (calculations detailed in Appendix 8-D) and OMERS pension costs (calculations detailed in Appendix 8-E), incremental regulatory costs, and Hydro One LV charges.

22. THESL believes that the proposed 23-month recovery period will dovetail with the expiry of the rate rider currently in place to retire THESL's regulatory asset accounts. When taken in isolation, this new rate rider will tend to increase overall distribution rates to customers. However, THESL submits that, because it is proposing to start the recovery of these expense elements coincident with the overall

distribution rate decrease expected for 2006, the higher rate impact of the riders will be effectively offset. THESL expects any residual account balance after the 23-month period to be small. Further details on the proposed rate rider calculations are provided in Appendix 10-A, and the 2006 proposed rate riders are shown in Schedule 8-3.

Incremental RSVA Rate Rider

23. THESL has recorded a credit of $3.9 million RSVA balance including interest charges from January 1, 2004 to December 31, 2004. The Board, in a letter dated July 5, 2005, provided LDCs with instructions to adjust the levels of the Retail Transmission Service ("RTS") rates to address the over or under-recovery of the RTS rates. However, the Board has yet to provide a procedure for LDCs that have received rate orders for the Phase II Regulatory Asset Recovery to clear the post-2003 balances. THESL believes that it is appropriate to clear the 2004 RSVA balances and associated interest charges in this rate filing. This would minimize THESL's balances in the RSVA accounts and would also bring THESL's recovery period in line with other LDCs that are applying for Phase II Regulatory Asset Recovery as part of the 2006 electricity distribution rate filing. THESL requests Board approval to clear the 2004 RSVA balances and associated interest charges by an adjustment to the current rate riders.

24. In keeping with the methodology used in the Phase II Regulatory Asset Recovery, the RSVA amounts will be allocated to the various customer

classes based on kWh consumption and the allocated amounts to each customer class will be collected through a volumetric charge.

Incremental OEB Fees and OMERS Pension Costs Rate Rider

25. As part of this Application for rates effective May 1, 2006, THESL requests approval to recover the incremental costs associated with Board fees and pension costs (account 1508) up to April 30, 2006. Currently there is no mechanism in place for the recovery of these incremental costs.

26. THESL estimates the deferred amounts from incremental OEB costs and incremental pension costs to equal approximately $12.3 million ($5.0 million for incremental OEB costs and $7.3 million for increased pension costs). Derivation of the OEB fees and OMERS pension cost deferral amounts are shown in Appendix 8-D and Appendix 8-E, respectively.

27. For ease of application, THESL requests approval from the Board to (a) allocate the rate rider revenue on the basis of 2006 estimated distribution revenue by class, and (b) collect the revenue via a volumetric charge.

Hydro One Low Voltage Costs Rate Rider

28. THESL is also seeking to recover Hydro One LV charge amounts for the period January 1, 2004 to April 30, 2006 as a further rate rider adjustment. THESL has based its LV charges for this period on data contained in the Board's letter dated July 25, 2005 regarding "2006 Electricity Distribution Rates – Amended Regulatory Assets Worksheet

for remaining distributors – Placeholder for Hydro One charges to embedded distributors for the period January 1, 2004 to April 30, 2006" (attached as Appendix 8-F). The total LV costs and other minor adjustments for the January 2004 to April 2006 period for THESL are shown to be $243,507.

THESL is proposing to allocate the Hydro One LV charge amounts to the various customer classes based on kWh consumption. The allocated amounts will be collected through the volumetric charges.

Regulatory Costs Variance Account

30. By letter dated December 20, 2004 the OEB approved Account 1508 – Other Regulatory Assets – sub-account OEB Cost Assessments that allows LDCs to record OEB costs in order that these costs may be given consideration for recovery in the future (i.e. May 1, 2006).

31. By way of this Application, THESL requests that the scope of this account be modified, or that a new variance account be established to allow the recording, for reconciliation at a later date, of the differences, if any, between the amounts recoverable in THESL's OEB-approved revenue requirement on account of Electrical Safety Authority fees and regulatory costs associated with regulatory proceedings (including, without limitation, intervenor, consultant, and legal costs), and the actual costs incurred by THESL in this regard. These may include, without limitation, ratemaking proceedings; combined proceedings on matters relating to OEB Codes; or policy oriented proceedings conducted by the Board. THESL proposes that estimates of these costs be factored into

the derivation of rates effective May 1, 2006 and that this account track the variance of estimated-to-actual costs for reconciliation in future rate adjustments, as appropriate. In years in which THESL participates in unexpected OEB proceedings, the variance account balance will be in THESL's favour. In years in which THESL participates in fewer regulatory proceedings, the balance will favour the customer.

32. THESL believes this to be a reasonable request given (1) the significant costs that can arise out of participation in the OEB's proceedings and initiatives and the uncertainty from year to year as to the numbers of proceedings the Board will convene and their anticipated cost; (2) the desire to prevent both the ratepayer and the shareholder from benefiting at the expense of the other party with regard to the costs associated with these proceedings; and (3) the fact that the underlying circumstances associated with this risk are beyond THESL's ability to control. For example, it was not possible for THESL to predict prior to the spring of 2003 that the Board would convene a combined proceeding on service area amendments (in which THESL submits that it was reasonable for it to participate); it was also not possible to know that the Board would convene oral proceedings for the final approval of the regulatory asset balances for THESL and a select group of other distributors in 2004. These and other proceedings have been very costly for THESL and, it expects, for other LDCs. THESL requests that the abovementioned modification, or the establishment of the new variance account, be effective May 1, 2006.

SCHEDULE 8-1 DERIVATION OF BASE REVENUE REQUIREMENT

Row	Revenue Requirement	$	Source/Comments
1	Service Revenue Requirement	481,300,553	(Rate Base X Cost of Capital) + Distribution Expenses + PILS
2	Revenue from Specific Service Charges and Late Payment Charges	Included in Total Revenue Offset in Row 4	Schedule 11-3
3	Revenue from other Board-approved charges	Included in Total Revenue Offset in Row 4	Details to be provided below
4	Total Revenue Offset	24,504,437	Row 6 from Schedule 8-2
5	Base Revenue Requirement	456,796,116	

Row 3 includes USoA accounts 4080(b), 4080(c), 4082, 4084. Please provide data here on the following two components of row 3:

RPP Administration Charge	1,654,435
Retailers' Service Charges	1,757,561
Service Transaction Request (STR) Charge	5,320
Wheeling revenue, with Tier 1 adjustment, if applicable: ____________________	

Additional comments regarding Schedule 8-1, if necessary.

SCHEDULE 8-2: REVENUE FROM SOURCES OTHER THAN BOARD-APPROVED

Row	Description of Revenue	2006 Revenue Offset	Comments
1			
2	Revenue from Late Payment Charges and Specific Service Charges	11,474,109	
3			
4	Other Income / Deductions	9,705,989	
5	Investment Income	3,324,338	
6	Total Revenue Offset # 2	24,504,437	Rows 2 + 4 + 5 Transferred to Row 4 of Schedule 8-1

Notes:
This schedule has been modified to conform to the calculation in Sheet 5-5 of the 2006 EDR model.

SCHEDULE 8-3: REGULATORY ASSET RECOVERY

Class	2005 Rate Rider (1)	2006 Incremental Rate Riders (2)	2006 Rate Rider (3)
Residential	$0.0028/kWh	$0.0004/kWh	$0.0032/kWh
GS < 50 kW	$0.0012/kWh	$0.0003/kWh	$0.0015/kWh
GS 50 to 1000 kW (Non Interval)	$0.26/kVA	$0.05/kVA	$0.31/kVA
GS 50 to 1000 kW (Interval)	$0.05/kVA	$0.04/kVA	$0.09/kVA
Intermediate User (1000 - 5000 kW)	$0.04/kVA	$0.03/kVA	$0.07/kVA
Large User > 5,000 kW	$0.05/kVA	$0.02/kVA	$0.07/kVA
Scattered Load	$0.0012/kWh	$0.0002/kWh	$0.0014/kWh
Street Lighting	$0.03/kVA	$0.05/kVA	$0.08/kVA

Notes:

(1) 2005 rate rider is a separate amount, not a component of the volumetric distribution rate. It represents Phase II of Regulatory Assets Recovery

(2) 2006 Incremental rate rider includes OMERS pension costs and OEB fees deferral, 2004 RSVA, and Hydro One LV Charges

(3) Adjusted for 30 Days of Service

APPENDIX 8-A

2.1.5 Performance Based Regulation

Output and Revenues

Please provide the following data for the end of year: 2002
***** represents compulsory fields
NOTE: Utilities that merged or were acquired subsequent to the reporting year must report data relevant to the entity as it existed prior to the merger or acquisition.

	2002	
(1) ANNUAL WHOLESALE COST OF POWER ($)	$ 1,960,852,000	*
(2) WHOLESALE KWH (kWh)	27,070,380,307	*
(3) RETAIL KWH (kWh)	26,177,019,147	*
(4) DISTRIBUTION SYSTEM LOSSES (kWh)	893,361,160	*

CUSTOMERS, DEMAND AND REVENUES

Consumer Class	(5) Number of Customers	(6) Billed kWh	(7) Billed **kVA**	(8) Distribution Revenue
Total	665,044	26,177,019,147	43,696,886	$ 426,223,187
(A) Residential	586,714	5,641,748,572		$ 168,793,311
(B) General Service	78,283	17,573,266,919	37,537,173	$ 237,034,715
(C) Large Use (>5,000 kW)	46	2,855,000,730	5,842,187	$ 18,775,190
(D) Street Lighting	1	107,002,926	317,526	$ 1,619,971
(E) Sentinel Lighting	-			

2.1.5 Performance Based Regulation

Output and Revenues

Please provide the following data for the end of year: 2003
***** represents compulsory fields
NOTE: Utilities that merged or were acquired subsequent to the reporting year must report data relevant to the entity as it existed prior to the merger or acquisition.

	2003	
(1) ANNUAL WHOLESALE COST OF POWER ($)	$ 1,934,501,000	*
(2) WHOLESALE KWH (kWh)	26,517,052,119	*
(3) RETAIL KWH (kWh)	25,604,519,835	*
(4) DISTRIBUTION SYSTEM LOSSES (kWh)	912,532,285	*

CUSTOMERS, DEMAND AND REVENUES

Consumer Class	(5) Number of Customers	(6) Billed kWh	(7) Billed **kVA**	(8) Distribution Revenue
Total	668,626	25,604,519,835	43,364,987	$ 440,007,992
(A) Residential	590,109	5,420,267,739		$ 173,180,165
(B) General Service	78,469	17,507,025,504	37,687,313	$ 247,065,117
(C) Large Use (>5,000 kW)	47	2,569,929,397	5,360,148	$ 18,079,551
(D) Street Lighting	1	107,297,194	317,526	$ 1,683,159
(E) Sentinel Lighting	-			

2.1.5 Performance Based Regulation

Output and Revenues

Please provide the following data for the end of year: 2004
***** represents compulsory fields
NOTE: Utilities that merged or were acquired subsequent to the reporting year must report data relevant to the entity as it existed prior to the merger or acquisition.

	2004	
(1) ANNUAL WHOLESALE COST OF POWER ($)	$ 1,798,007,911	*
(2) WHOLESALE KWH (kWh)	26,417,144,859	*
(3) RETAIL KWH (kWh)	25,558,066,373	*
(4) DISTRIBUTION SYSTEM LOSSES (kWh)	859,078,486	*

CUSTOMERS, DEMAND AND REVENUES

Consumer Class	(5) Number of Customers	(6) Billed kWh	(7) Billed **kVA**	(8) Distribution Revenue
Total	673,173	25,508,050,686	42,779,757	$ 437,076,536
(A) Residential	594,976	5,428,344,270		$ 174,346,550
(B) General Service	78,149	17,377,227,059	37,061,999	$ 242,881,277
(C) Large Use (>5,000 kW)	47	2,593,568,077	5,409,480	$ 18,200,406
(D) Street Lighting	1	108,911,280	308,277	$ 1,648,304
(E) Sentinel Lighting	-			

(3): There is a slight difference between the Retail kWh and the Billed kWh. The Retail kWh was determined based on thorough analysis of the billing quantities after all the 2004 consumption has been billed up to the end of March 2005, whereas, the "Billed kWh" by customer class has been accrued throughout the year of 2004.

APPENDIX 8-B: 2004 ADJUSTMENT SUMMARY

		2004 Balance	Adjustment		Adjusted 2004 Balance	2006 Forecast
4080	Retailer Service - fix	(2,880)	2,880	a	-	0
	Retailer Service - variable	(868,891)	868,891	b	-	0
	RPP Admin Charges	(1,654,435)	1,654,435	c	-	0
	Distribution Services Revenue	**(2,526,206)**	**2,526,206**		**-**	**-**
4082	Retailers Fixed Charges		(2,880)	a	(2,880)	(2,880)
	Variable Variable Charge		(868,891)	b	(868,891)	(868,891)
	DCB consolidated billing	(497,754)			(497,754)	(497,754)
	RCB consolidated billing	23,582			23,582	23,582
	Other Service fees	(411,618)			(411,618)	(411,618)
	Retail Services Revenues	**(885,790)**	**(871,771)**		**(1,757,561)**	**(1,757,561)**
4084	STR request	(3,678)			(3,678)	(3,678)
	STR processing	(1,600)			(1,600)	(1,600)
	Other STR processing	(42)			(42)	(42)
	Service Transaction Requests (STF	**(5,320)**	**-**		**(5,320)**	**(5,320)**
4090	Electric Services Incidental to Energy Sales					
	(Parking Spot for RPP Admin Charge)		**(1,654,435)**	**c**	**(1,654,435)**	**(1,654,435)**
4210	Fleet rental	(58,322)			(58,322)	(58,322)
	Property rental	-			-	-
	Duct	(7,444,564)			(7,444,564)	(4,794,911)
	Pole	(1,263,014)	1,263,014	e	-	-
	Misc rent	(4,358)			(4,358)	(4,358)
	RIMS line	(447,572)			(447,572)	(447,572)
	Parking	(1,200)			(1,200)	(1,200)
	Other property rental	(29,147)			(29,147)	(29,147)
	Rent from Electric Property	**(9,248,177)**	**1,263,014**		**(7,985,163)**	**(5,306,363)**
4225	Retailers late payment	(11,054)			(11,054)	(11,054)
	Customer late payment	(4,595,014)			(4,595,014)	(4,595,014)
	Late Payment Charges	(4,606,068)	-		(4,606,068)	(4,606,068)
4235	Discount Settlement - Suppliers	(152,774)	152,774	d	-	
	Misc Revenue	(100)	100	d	-	
	Customers account set-up	(859,598)			(859,598)	
	Connection-reconnection	(160,867)			(160,867)	
	NSF Collection charges	(116,085)			(116,085)	
	Collection		-517,967	f	(517,967)	
	Stale-dated cheque	(285,733)	285,733	d	-	
	TTC rectification	(303,900)	303,900	d	-	**Calculated in**
	Water meter reading	(239,804)	239,804	d	-	**Schedule 11-3**
	Miscellaneous Service Revenues	**(2,118,861)**	**464,344**		**(1,654,517)**	**(5,428,360)**
4215	**Other Utility Operating Income**		**(982,311)**	**d**	**(982,311)**	**(982,311)**
4230	Sales of Water and Water Power					
	(Parking Spot for Pole Attachment)		**(1,263,014)**	**e**	**(1,263,014)**	**(1,439,681)**
5330	**Collection Charges**	**-517,967**	**517,967**	**f**	**-**	**-**
4405-4415	**Investment Income**	**(3,057,180)**			**(3,057,180)**	**(3,057,180)**
4325	Merchandise and Jobbing Revenue	(15,897,440)	6,980,309		(8,917,131)	(8,917,131)
4330	Merchandise and Jobbing Expenses	8,649,973			8,649,973	8,649,973
	Net Merchandise and Jobbing				**(267,158)**	**(267,158)**
Total		**(19,908,389)**	**-**		**(19,908,389)**	**(24,504,437)**

APPENDIX 8-C:
Summary of 2004 RSVA Transactions

	RSVA Charges	Interests	Total
RSVA-WMS	1,232,193	19,871	1,252,063
RSVA-One time	1,564,952	72,836	1,637,788
RSVA-NW	(955,511)	(39,929)	(995,440)
RSVA-CN	(5,487,216)	(181,967)	(5,669,183)
RSVA-PW	(93,395)	(3,400)	(96,794)
Total	(3,738,977)	(132,589)	(3,871,566)

**APPENDIX 8-C:
RSVA-WMS**

Interest rate: 0.5667%

Month	Opening Balance	Charge	Ending Balance	Interests	Cumulative Interest	Cumulative Total
May-02	-	(5,028,105.73)	(5,028,105.73)	-	-	(5,028,105.73)
Jun-02	(5,028,105.73)	(4,216,910.97)	(9,245,016.69)	(28,492.60)	(28,492.60)	(9,273,509.29)
Jul-02	(9,245,016.69)	13,589,410.72	4,344,394.03	(52,388.43)	(80,881.03)	4,263,513.00
Aug-02	4,344,394.03	11,706,545.62	16,050,939.65	24,618.23	(56,262.79)	15,994,676.85
Sep-02	16,050,939.65	24,274,649.39	40,325,589.03	90,955.32	34,692.53	40,360,281.56
Oct-02	40,325,589.03	(1,578,970.35)	38,746,618.68	228,511.67	263,204.20	39,009,822.88
Nov-02	38,746,618.68	(2,640,415.37)	36,106,203.31	219,564.17	482,768.37	36,588,971.68
Dec-02	36,106,203.31	196,130.33	36,302,333.64	204,601.82	687,370.19	36,989,703.84
Jan-03	36,302,333.64	76,841.28	36,379,174.92	205,713.22	893,083.42	37,272,258.34
Feb-03	36,379,174.92	630.60	36,379,805.52	206,148.66	1,099,232.07	37,479,037.59
Mar-03	36,379,805.52	2,273.87	36,382,079.39	206,152.23	1,305,384.31	37,687,463.69
Apr-03	36,382,079.39	(19,014.37)	36,363,065.02	206,165.12	1,511,549.42	37,874,614.44
May-03	36,363,065.02	32,977.14	36,396,042.16	206,057.37	1,717,606.79	38,113,648.95
Jun-03	36,396,042.16	(11,189.25)	36,384,852.91	206,244.24	1,923,851.03	38,308,703.94
Jul-03	36,384,852.91	(22,758.34)	36,362,094.57	206,180.83	2,130,031.86	38,492,126.43
Aug-03	36,362,094.57	(8,482.26)	36,353,612.31	206,051.87	2,336,083.73	38,689,696.04
Sep-03	36,353,612.31	7,561.78	36,361,174.09	206,003.80	2,542,087.54	38,903,261.63
Oct-03	36,361,174.09	39,172.75	36,400,346.84	206,046.65	2,748,134.19	39,148,481.03
Nov-03	36,400,346.84	(19,917.28)	36,380,429.56	206,268.63	2,954,402.82	39,334,832.38
Dec-03	36,380,429.56	(1,933,796.32)	34,446,633.25	206,155.77	3,160,558.59	37,607,191.83
Jan-04	-	(492,913.80)	(492,913.80)	-	-	(492,913.80)
Feb-04	(492,913.80)	(53,697.32)	(546,611.13)	(2,793.18)	(2,793.18)	(549,404.30)
Mar-04	(546,611.13)	1,178.73	(545,432.40)	(3,097.46)	(5,890.64)	(551,323.04)
Apr-04	(545,432.40)	7,249.21	(538,183.19)	(3,090.78)	(8,981.42)	(547,164.61)
May-04	(538,183.19)	(43,478.96)	(581,662.15)	(3,049.70)	(12,031.13)	(593,693.28)
Jun-04	(581,662.15)	42,795.82	(538,866.32)	(3,296.09)	(15,327.22)	(554,193.54)
Jul-04	(538,866.32)	2,431,160.02	1,892,293.70	(3,053.58)	(18,380.79)	1,873,912.90
Aug-04	1,892,293.70	(652,268.03)	1,240,025.66	10,723.00	(7,657.79)	1,232,367.87
Sep-04	1,240,025.66	(6,399.02)	1,233,626.64	7,026.81	(630.98)	1,232,995.66
Oct-04	1,233,626.64	(12,648.83)	1,220,977.81	6,990.55	6,359.57	1,227,337.38
Nov-04	1,220,977.81	(57,665.35)	1,163,312.46	6,918.87	13,278.44	1,176,590.90
Dec-04	1,163,312.46	68,880.30	1,232,192.76	6,592.10	19,870.55	1,252,063.30

APPENDIX 8-C:
RSVA -one time

	Opening Balance	Charge	Ending Balance	Interest	0.5667% Cumulative Interest	Cumulative Total
May-02	-	-	-	-	-	-
Jun-02	-	32,807	32,807	-	-	32,806.94
Jul-02	32,807	259,888	292,695	186	185.91	292,880.43
Aug-02	292,695	220,544	513,239	1,659	1,844.51	515,083.32
Sep-02	513,239	522,652	1,035,890	2,908	4,752.86	1,040,643.33
Oct-02	1,035,890	310,427	1,346,318	5,870	10,622.91	1,356,940.53
Nov-02	1,346,318	67,204	1,413,521	7,629	18,252.04	1,431,773.30
Dec-02	1,413,521	163,289	1,576,810	8,010	26,261.99	1,603,072.26
Jan-03	1,576,810	74,078	1,650,888	8,935	35,197.25	1,686,085.30
Feb-03	1,650,888	57,435	1,708,323	9,355	44,552.28	1,752,875.51
Mar-03	1,708,323	182,159	1,890,482	9,680	54,232.78	1,944,714.81
Apr-03	1,890,482	70,277	1,960,760	10,713	64,945.51	2,025,705.03
May-03	1,960,760	64,153	2,024,912	11,111	76,056.49	2,100,968.64
Jun-03	2,024,912	45,255	2,070,167	11,475	87,530.99	2,157,698.22
Jul-03	2,070,167	61,570	2,131,737	11,731	99,261.94	2,230,998.80
Aug-03	2,131,737	38,481	2,170,217	12,080	111,341.78	2,281,559.21
Sep-03	2,170,217	73,606	2,243,824	12,298	123,639.68	2,367,463.25
Oct-03	2,243,824	11,426	2,255,249	12,715	136,354.68	2,391,604.00
Nov-03	2,255,249	73,050	2,328,300	12,780	149,134.42	2,477,434.06
Dec-03	2,328,300	1,981,240	4,309,540	13,194	162,328.12	4,471,867.98
Jan-04	-	820,980	820,980	-	-	820,980.08
Feb-04	820,980	91,391	912,372	4,652	4,652.22	917,023.79
Mar-04	912,372	74,581	986,952	5,170	9,822.33	996,774.65
Apr-04	986,952	69,520	1,056,473	5,593	15,415.06	1,071,887.74
May-04	1,056,473	49,283	1,105,756	5,987	21,401.73	1,127,157.82
Jun-04	1,105,756	64,830	1,170,586	6,266	27,667.69	1,198,253.53
Jul-04	1,170,586	26,966	1,197,552	6,633	34,301.01	1,231,852.87
Aug-04	1,197,552	125,084	1,322,636	6,786	41,087.13	1,363,722.90
Sep-04	1,322,636	54,096	1,376,732	7,495	48,582.07	1,425,313.73
Oct-04	1,376,732	50,521	1,427,253	7,801	56,383.55	1,483,636.47
Nov-04	1,427,253	48,826	1,476,079	8,088	64,471.31	1,540,550.02
Dec-04	1,476,079	88,873.53	1,564,952	8,364	72,835.76	1,637,788.00

APPENDIX 8-C:
RSVA-Network

	Opening Balance	Charge	Ending Balance	Interest	Cumulative Interest (0.5667%)	Cumulative Total
May-02	-	72,933.17	72,933.17	-	-	72,933.17
Jun-02	72,933.17	1,758,124.26	1,831,057.43	413.29	413.29	1,831,470.72
Jul-02	1,831,057.43	194,212.69	2,025,270.13	10,375.99	10,789.28	2,036,059.41
Aug-02	2,025,270.13	(148,242.01)	1,877,028.12	11,476.53	22,265.81	1,899,293.93
Sep-02	1,877,028.12	1,449,216.32	3,326,244.45	10,636.49	32,902.30	3,359,146.75
Oct-02	3,326,244.45	(186,543.83)	3,139,700.62	18,848.72	51,751.02	3,191,451.64
Nov-02	3,139,700.62	(200,273.36)	2,939,427.26	17,791.64	69,542.66	3,008,969.92
Dec-02	2,939,427.26	(836,262.15)	2,103,165.11	16,656.75	86,199.41	2,189,364.53
Jan-03	2,103,165.11	(850,023.65)	1,253,141.47	11,917.94	98,117.35	1,351,258.81
Feb-03	1,253,141.47	988,688.04	2,241,829.51	7,101.13	105,218.48	2,347,047.99
Mar-03	2,241,829.51	(507,231.10)	1,734,598.41	12,703.70	117,922.18	1,852,520.59
Apr-03	1,734,598.41	(210,450.67)	1,524,147.74	9,829.39	127,751.58	1,651,899.31
May-03	1,524,147.74	(1,055,732.08)	468,415.66	8,636.84	136,388.41	604,804.07
Jun-03	468,415.66	2,177,873.16	2,646,288.81	2,654.36	139,042.77	2,785,331.58
Jul-03	2,646,288.81	305,748.60	2,952,037.41	14,995.64	154,038.40	3,106,075.82
Aug-03	2,952,037.41	495,378.96	3,447,416.37	16,728.21	170,766.62	3,618,182.99
Sep-03	3,447,416.37	(77,180.30)	3,370,236.07	19,535.36	190,301.98	3,560,538.05
Oct-03	3,370,236.07	(1,134,435.34)	2,235,800.73	19,098.00	209,399.98	2,445,200.71
Nov-03	2,235,800.73	(321,095.64)	1,914,705.09	12,669.54	222,069.52	2,136,774.61
Dec-03	1,914,705.09	(920,342.91)	994,362.18	10,850.00	232,919.51	1,227,281.69
Jan-04	-	(644,661.63)	(644,661.63)	-	-	(644,661.63)
Feb-04	(644,661.63)	312,546.79	(332,114.84)	(3,653.08)	(3,653.08)	(335,767.92)
Mar-04	(332,114.84)	(971,331.63)	(1,303,446.47)	(1,881.98)	(5,535.07)	(1,308,981.54)
Apr-04	(1,303,446.47)	(563,103.01)	(1,866,549.48)	(7,386.20)	(12,921.26)	(1,879,470.74)
May-04	(1,866,549.48)	(383,474.77)	(2,250,024.24)	(10,577.11)	(23,498.38)	(2,273,522.62)
Jun-04	(2,250,024.24)	1,508,361.45	(741,662.80)	(12,750.14)	(36,248.51)	(777,911.31)
Jul-04	(741,662.80)	938,170.35	196,507.56	(4,202.76)	(40,451.27)	156,056.29
Aug-04	196,507.56	422,061.28	618,568.84	1,113.54	(39,337.73)	579,231.11
Sep-04	618,568.84	22,279.78	640,848.62	3,505.22	(35,832.50)	605,016.12
Oct-04	640,848.62	(1,219,997.14)	(579,148.52)	3,631.48	(32,201.03)	(611,349.55)
Nov-04	(579,148.52)	(205,429.10)	(784,577.62)	(3,281.84)	(35,482.87)	(820,060.49)
Dec-04	(784,577.62)	(170,933.63)	(955,511.25)	(4,445.94)	(39,928.81)	(995,440.06)

APPENDIX 8-C:
RSVA-Connection

	Opening Balance	Charge	Ending Balance	Interest	Cumulative Interest (0.5667%)	Cumulative Total
May-02	-	(438,593.78)	(438,593.78)	-	-	(438,593.78)
Jun-02	(438,593.78)	832,906.24	394,312.46	(2,485.36)	(2,485.36)	391,827.10
Jul-02	394,312.46	(289,995.91)	104,316.55	2,234.44	(250.93)	104,065.63
Aug-02	104,316.55	(543,550.91)	(439,234.36)	591.13	340.20	(438,894.16)
Sep-02	(439,234.36)	803,156.39	363,922.03	(2,488.99)	(2,148.80)	361,773.24
Oct-02	363,922.03	(376,054.48)	(12,132.45)	2,062.22	(86.57)	(12,219.02)
Nov-02	(12,132.45)	(458,406.04)	(470,538.49)	(68.75)	(155.32)	(470,693.81)
Dec-02	(470,538.49)	(997,683.48)	(1,468,221.98)	(2,666.38)	(2,821.71)	(1,471,043.68)
Jan-03	(1,468,221.98)	(974,314.27)	(2,442,536.24)	(8,319.92)	(11,141.63)	(2,453,677.87)
Feb-03	(2,442,536.24)	436,892.23	(2,005,644.01)	(13,841.04)	(24,982.67)	(2,030,626.68)
Mar-03	(2,005,644.01)	(721,533.00)	(2,727,177.01)	(11,365.32)	(36,347.98)	(2,763,524.99)
Apr-03	(2,727,177.01)	(444,671.67)	(3,171,848.68)	(15,454.00)	(51,801.99)	(3,223,650.67)
May-03	(3,171,848.68)	(948,306.24)	(4,120,154.92)	(17,973.81)	(69,775.80)	(4,189,930.71)
Jun-03	(4,120,154.92)	1,168,123.87	(2,952,031.04)	(23,347.54)	(93,123.34)	(3,045,154.39)
Jul-03	(2,952,031.04)	(188,599.10)	(3,140,630.15)	(16,728.18)	(109,851.52)	(3,250,481.66)
Aug-03	(3,140,630.15)	(158,260.43)	(3,298,890.58)	(17,796.90)	(127,648.42)	(3,426,539.00)
Sep-03	(3,298,890.58)	523,430.20	(2,775,460.38)	(18,693.71)	(146,342.13)	(2,921,802.52)
Oct-03	(2,775,460.38)	(1,210,286.18)	(3,985,746.56)	(15,727.61)	(162,069.74)	(4,147,816.31)
Nov-03	(3,985,746.56)	(413,512.80)	(4,399,259.36)	(22,585.90)	(184,655.64)	(4,583,915.00)
Dec-03	(4,399,259.36)	(1,045,051.45)	(5,444,310.81)	(24,929.14)	(209,584.78)	(5,653,895.59)
Jan-04	-	(928,803.22)	(928,803.22)	-	-	(928,803.22)
Feb-04	(928,803.22)	(139,922.85)	(1,068,726.07)	(5,263.22)	(5,263.22)	(1,073,989.28)
Mar-04	(1,068,726.07)	(1,075,158.28)	(2,143,884.35)	(6,056.11)	(11,319.33)	(2,155,203.68)
Apr-04	(2,143,884.35)	(755,916.71)	(2,899,801.06)	(12,148.68)	(23,468.01)	(2,923,269.07)
May-04	(2,899,801.06)	(848,150.91)	(3,747,951.98)	(16,432.21)	(39,900.22)	(3,787,852.19)
Jun-04	(3,747,951.98)	730,920.27	(3,017,031.70)	(21,238.39)	(61,138.61)	(3,078,170.32)
Jul-04	(3,017,031.70)	110,441.65	(2,906,590.05)	(17,096.51)	(78,235.12)	(2,984,825.18)
Aug-04	(2,906,590.05)	(195,131.08)	(3,101,721.14)	(16,470.68)	(94,705.80)	(3,196,426.94)
Sep-04	(3,101,721.14)	(230,735.37)	(3,332,456.51)	(17,576.42)	(112,282.22)	(3,444,738.73)
Oct-04	(3,332,456.51)	(1,068,081.99)	(4,400,538.50)	(18,883.92)	(131,166.14)	(4,531,704.64)
Nov-04	(4,400,538.50)	(163,803.11)	(4,564,341.61)	(24,936.38)	(156,102.53)	(4,720,444.14)
Dec-04	(4,564,341.61)	(922,874.29)	(5,487,215.90)	(25,864.60)	(181,967.13)	(5,669,183.03)

APPENDIX 8-C:

RSVA-Power

	Opening Balance	Charge	Ending Balance	Interest	0.5667% Cumulative Interest	Cumulative Total
May-02	-	(7,330,453.66)	(7,330,453.66)	-	-	(7,330,453.66)
Jun-02	(7,330,453.66)	(188,383.51)	(7,518,837.16)	(41,539.24)	(41,539.24)	(7,560,376.40)
Jul-02	(7,518,837.16)	(42,165.49)	(7,561,002.66)	(42,606.74)	(84,145.98)	(7,645,148.64)
Aug-02	(7,561,002.66)	(35,330.37)	(7,596,333.02)	(42,845.68)	(126,991.66)	(7,723,324.68)
Sep-02	(7,596,333.02)	(24,613.13)	(7,620,946.15)	(43,045.89)	(170,037.55)	(7,790,983.70)
Oct-02	(7,620,946.15)	(20,931.02)	(7,641,877.18)	(43,185.36)	(213,222.91)	(7,855,100.09)
Nov-02	(7,641,877.18)	(21,325.55)	(7,663,202.72)	(43,303.97)	(256,526.88)	(7,919,729.61)
Dec-02	(7,663,202.72)	106,737.62	(7,556,465.10)	(43,424.82)	(299,951.70)	(7,856,416.80)
Jan-03	(7,556,465.10)	(28,368.45)	(7,584,833.55)	(42,819.97)	(342,771.67)	(7,927,605.21)
Feb-03	(7,584,833.55)	(33,696.87)	(7,618,530.41)	(42,980.72)	(385,752.39)	(8,004,282.81)
Mar-03	(7,618,530.41)	(11,245.27)	(7,629,775.69)	(43,171.67)	(428,924.06)	(8,058,699.75)
Apr-03	(7,629,775.69)	(11,609.41)	(7,641,385.10)	(43,235.40)	(472,159.46)	(8,113,544.55)
May-03	(7,641,385.10)	(99,920.97)	(7,741,306.07)	(43,301.18)	(515,460.64)	(8,256,766.71)
Jun-03	(7,741,306.07)	7,325.44	(7,733,980.63)	(43,867.40)	(559,328.04)	(8,293,308.67)
Jul-03	(7,733,980.63)	104,283.86	(7,629,696.77)	(43,825.89)	(603,153.93)	(8,232,850.70)
Aug-03	(7,629,696.77)	46,384.83	(7,583,311.94)	(43,234.95)	(646,388.88)	(8,229,700.82)
Sep-03	(7,583,311.94)	53,973.58	(7,529,338.36)	(42,972.10)	(689,360.98)	(8,218,699.34)
Oct-03	(7,529,338.36)	82.97	(7,529,255.38)	(42,666.25)	(732,027.23)	(8,261,282.61)
Nov-03	(7,529,255.38)	58,542.42	(7,470,712.97)	(42,665.78)	(774,693.01)	(8,245,405.98)
Dec-03	(7,470,712.97)	(10,510.77)	(7,481,223.74)	(42,334.04)	(817,027.05)	(8,298,250.79)
Jan-04	-	(15,693.09)	(15,693.09)	-	-	(15,693.09)
Feb-04	(15,693.09)	(34,235.65)	(49,928.75)	(88.93)	(88.93)	(50,017.67)
Mar-04	(49,928.75)	(10,056.81)	(59,985.55)	(282.93)	(371.86)	(60,357.41)
Apr-04	(59,985.55)	(8,707.41)	(68,692.97)	(339.92)	(711.78)	(69,404.74)
May-04	(68,692.97)	(2,810.58)	(71,503.55)	(389.26)	(1,101.04)	(72,604.59)
Jun-04	(71,503.55)	28,321.51	(43,182.04)	(405.19)	(1,506.22)	(44,688.26)
Jul-04	(43,182.04)	(2,482)	(45,664.19)	(244.70)	(1,750.92)	(47,415.11)
Aug-04	(45,664.19)	(3,813)	(49,477.40)	(258.76)	(2,009.68)	(51,487.08)
Sep-04	(49,477.40)	(12,900)	(62,377.87)	(280.37)	(2,290.06)	(64,667.93)
Oct-04	(62,377.87)	2,739	(59,638.96)	(353.47)	(2,643.53)	(62,282.49)
Nov-04	(59,638.96)	(14,178)	(73,817.36)	(337.95)	(2,981.48)	(76,798.85)
Dec-04	(73,817.36)	(19,577)	(93,394.64)	(418.30)	(3,399.78)	(96,794.43)

APPENDIX 8-D: OEB FEES DEFERRAL

				Carryinng Charges		0.479%	
	Opening Balance	Charges	Ending Balance	Beginning Balance	Carrying Charge	Interest	Total
Jul-05	-	457,056	457,056		-	-	457,056
Aug-04	457,056	457,056	914,112	-	2,190	2,190	916,302
Sep-04	914,112	-	914,112	2,190	4,380	6,570	920,682
Oct-04	914,112	-	914,112	6,570	4,380	10,950	925,062
Nov-04	914,112	457,056	1,371,167	10,950	4,380	15,330	1,386,498
Dec-04	1,371,167	-	1,371,167	15,330	6,570	21,901	1,393,068
Jan-05	1,371,167	-	1,371,167	21,901	6,570	28,471	1,399,638
Feb-05	1,371,167	-	1,371,167	28,471	6,570	35,041	1,406,208
Mar-05	1,371,167	-	1,371,167	35,041	6,570	41,611	1,412,778
Apr-05	1,371,167	261,451	1,632,618	41,611	6,570	48,181	1,680,800
May-05	1,632,618	522,902	2,155,520	48,181	7,823	56,004	2,211,525
Jun-05	2,155,520	-	2,155,520	56,004	10,329	66,333	2,221,853
Jul-05	2,155,520	784,353	2,939,873	66,333	10,329	76,661	3,016,535
Aug-05	2,939,873	-	2,939,873	76,661	14,087	90,748	3,030,622
Sep-05	2,939,873	-	2,939,873	90,748	14,087	104,835	3,044,708
Oct-05	2,939,873	784,353	3,724,226	104,835	14,087	118,922	3,843,148
Nov-05	3,724,226	-	3,724,226	118,922	17,845	136,767	3,860,994
Dec-05	3,724,226	-	3,724,226	136,767	17,845	154,613	3,878,839
Jan-06	3,724,226	784,353	4,508,579	154,613	17,845	172,458	4,681,037
Feb-06	4,508,579	-	4,508,579	172,458	21,604	194,061	4,702,641
Mar-06	4,508,579	-	4,508,579	194,061	21,604	215,665	4,724,244
Apr-06	4,508,579	261,451	4,770,030	215,665	21,604	237,269	5,007,299

APPENDIX 8-E:
PENSION DEFERRAL SCHEDULE BY MONTH (Jan-05 to Apr-06)

	Opening Balance	Monthly Deferral	Ending Balance	Carrying Charges 0.5667%	Carrying Charges Balance	Total Balance
Jan-05	-	376,131	376,131		-	376,131
Feb-05	376,131	376,131	752,263	2,131	2,131	754,394
Mar-05	752,263	750,554	1,502,817	4,263	6,394	1,509,211
Apr-05	1,502,817	376,131	1,878,949	8,516	14,910	1,893,859
May-05	1,878,949	376,155	2,255,104	10,647	25,558	2,280,661
Jun-05	2,255,104	376,155	2,631,259	12,779	38,336	2,669,595
Jul-05	2,631,259	376,155	3,007,414	14,910	53,247	3,060,661
Aug-05	3,007,414	376,155	3,383,569	17,042	70,289	3,453,858
Sep-05	3,383,569	565,026	3,948,595	19,174	89,463	4,038,058
Oct-05	3,948,595	376,684	4,325,279	22,375	111,838	4,437,117
Nov-05	4,325,279	376,684	4,701,964	24,510	136,348	4,838,311
Dec-05	4,701,964	376,684	5,078,648	26,644	162,992	5,241,640
Jan-06	5,078,648	417,842	5,496,489	28,779	191,771	5,688,261
Feb-06	5,496,489	417,842	5,914,331	31,147	222,918	6,137,249
Mar-06	5,914,331	632,543	6,546,874	33,515	256,433	6,803,307
Apr-06	6,546,874	417,842	6,964,716	37,099	293,532	7,258,248

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VT INCEPIT FIDELIS SIC PERMANET
Ontario

APPENDIX 8-F

July 25, 2005

To: All Electricity Distribution Utilities

Re: 2006 Electricity Distribution Rates
Amended Regulatory Assets Worksheet for remaining distributors
Placeholder for Hydro One charges to embedded distributors for the period January 1, 2004 to April 30, 2006

On July 12, 2005, the Board informed all distributors of changes made to the regulatory assets worksheet issued on June 16, 2005. Specifically, the Board informed distributors of minor changes that were made to some formulas as well as the addition of a placeholder for Hydro One's regulatory asset charges to embedded distributors in the form of an additional reporting period (January 1, 2004 to April 30, 2006). Also, on July 12, 2005, the Board issued revised versions of the worksheet, filing guidelines and worksheet documentation reflecting these changes.

Page 9 of the revised filing guidelines states that the Board will inform embedded distributors of their allocated amounts once they are provided by Hydro One. The regulatory asset amounts which are proposed to be allocated by Hydro One to its embedded distributors for the period January 1, 2004 to April 30, 2006 are attached as Appendix A.

Distributors should note that the allocators listed in row 4 of Appendix A are Hydro One's proposed allocators to the embedded distributors while row 5 lists the Board approved allocators that are used by the regulatory assets worksheet to allocate the respective account balances to customers.

In order to complete their regulatory assets filing, each embedded distributor should include its allocated amounts, proposed by Hydro One in Appendix A, in their corresponding accounts in column "M" of Sheet 1 of the revised worksheet ("Hydro One charges (if applicable) Jan.1-04 to Apr. 30-06") from cell M17 to M20 inclusive.

Amounts relating to Low Voltage charges should be included in account 1586 or cell M20 as per s.9.0.8 of the Board's Dec.9/04 Decision.

Distributors should note that Hydro One has also included amounts in account 1508 relating to Hydro One's pension and OEB costs. These amounts should be entered in cell M25 (currently not highlighted). Distributors should also amend the sum formula in cell N25 to include this new amount. The formula currently reads, "SUM(G25:J25)". The formula should be amended to read, "SUM(G25:M25)". The Board will not be issuing a revised worksheet to reflect this change; therefore, distributors should ensure that the amounts in cell M25 are included in the 1508 account total (cell N25).

The Board has not yet approved a class allocator for amounts in accounts 1508, 1525, 1574 and 2425 (other than amounts relating to rebate cheques and Hydro One's environmental and low voltage costs). Distributors may wish to propose distribution revenue as the appropriate class allocator for Hydro One's pension and OEB costs recorded in account 1508. Since the model does not include default allocators for amounts in the above accounts, distributors should ensure that the proposed allocator(s) are entered in column "D" of Sheet 2 of the worksheet and that the appropriate formulas are entered in column's "E" through "M" to apportion the appropriate amounts to the classes.

Finally, the allocated amounts that Hydro One has provided on the attached spreadsheet have not yet been approved for recovery by the Board. The amounts will form part of Hydro One's 2006 EDR application and are subject to approval by the Board as part of that application.

Any enquiries regarding the above amendments to the worksheet should be forwarded to Ted Antonopoulos at 416-440-8137.

Yours truly,

Original Signed By

John Zych
Board Secretary

APPENDIX 8-F:
HYDRO ONE's PROPOSED REGULATORY ASSET CHARGES TO EMBEDDED DISTRIBUTORS FOR JAN. 2004 TO APR. 2006

	A	BX	BY	CA	CB	CC	CD	CE
1		**Deferred LV costs (to be included in 1586)**	**Acct 1508 Pension and OEB costs**	**Acct 1580 RSVA WMSC**	**Acct 1582 RSVA One Time**	**Acct 1584 RSVA Network**	**Acct 1586 RSVA Connection**	**Total April 30, 2006 Reg. Asset Variance Balance**
2	**Total Amount**	$40,236,797	$1,863,350	$26,523	$54,585	($4,563,015)	($16,697,635)	$20,920,604
3	**Embedded Distributor**	by Deferred LV costs	by Deferred LV costs	by WMSC kWh	by WMSC kWh	by Network kW	by connection kW	
4		by kWhs to customers	by Dx revenue to customers	by kWhs to customers	by kWhs to customers	by kWhs to customers	by kWhs to customers	
5	Asphodel-Norwood Distribution Inc.	$118,507	$5,488			($4,197)	($15,282)	$104,516
6	Aurora Hydro Connections Limited	$745,589	$34,528			($152,056)	($554,089)	$73,972
7	Barrie Hydro Distribution Inc.	$736,665	$34,115			($139,340)	($506,372)	$125,067
8	Bluewater Power Distribution Corporation	$350,086	$16,212	$1,093	$2,249	($26,435)	($95,472)	$247,734
9	Brant County Power	$453,869	$21,018		$0	($70,521)	($269,236)	$135,131
10	Brantford Power Inc.	$216,816	$10,041		$0	($58,404)	($211,839)	-$43,387
11	Burlington Hydro Inc.	$243,617	$11,282		$0	($49,651)	($179,668)	$25,580
12	Cambridge & North Dumfries Hydro Inc.	$258,085	$11,952	`	$0	($12,632)	($47,812)	$209,592
13	Centre Wellington Hydro Ltd.	$316,337	$14,649		$0	($43,787)	($157,913)	$129,287
14	Chapleau Public Utilities Corp.	$189,764	$8,788		$0	($3,236)	($11,697)	$183,619
15	Chatham-Kent Hydro Inc.	$1,726,033	$79,932		$0	($85,693)	($309,489)	$1,410,783
16	Clinton Power Corporation	$318,667	$14,757		$0	($10,189)	($36,707)	$286,529
17	COLLUS Power Corp.	$756,842	$35,049		$0	($113,238)	($409,869)	$268,784
18	Cooperative Hydro Embrun Inc.	$51,813	$2,399	$653	$1,345	($8,653)	($31,724)	$15,833
19	Dutton Hydro Limited	$72,451	$3,355	$192	$394	($2,532)	($9,191)	$64,669
20	E.L.K. Energy Inc.	$629,682	$29,160		$0	($63,481)	($229,943)	$365,419
21	Enersource Hydro Mississauga	$2,396,106	$110,963		$0	($412,714)	($1,554,498)	$539,856
22	Erie Thames Power Lines Corporation	$817,609	$37,863		$0	($82,148)	($308,366)	$464,958
23	Espanola Regional Hydro Distribution Corporation	$309,864	$14,350		$0	($19,006)	($68,749)	$236,458
24	Essex Powerlines Corporation	$1,544,280	$71,515		$0	($176,329)	($655,171)	$784,295
25	Festival Hydro Inc.	$262,255	$12,145		$0	($18,555)	($67,048)	$188,797
26	Grand Valley Energy Inc.	$88,473	$4,097		$0	($2,842)	($10,410)	$79,319
27	Gravenhurst Hydro Electric Inc.	$219,387	$10,160		$0	($27,353)	($99,957)	$102,236
28	Greater Sudbury Hydro Inc	$72,870	$3,375	$868	$1,786	($10,950)	($40,435)	$27,513
29	Grimsby Power Incorporated	$308,507	$14,287		$0	($29,925)	($108,791)	$184,078
30	Halton Hills Hydro Inc.	$824,419	$38,179		$0	($144,732)	($526,292)	$191,573
31	Hamilton Hydro Inc.	$1,406,534	$65,136	$84	$174	($142,009)	($518,872)	$811,047
32	Hawkesbury Hydro Inc.	$237,727	$11,009		$0	($35,838)	($129,109)	$83,789
33	Hydro 2000 Inc. [Alfred-Plantagenet]	$232,670	$10,775	$617	$1,269	($7,931)	($28,791)	$208,610

APPENDIX 8-F

HYDRO ONE's PROPOSED REGULATORY ASSET CHARGES TO EMBEDDED DISTRIBUTORS FOR JAN. 2004 TO APR. 2006

	A	BX	BY	CA	CB	CC	CD	CE
1		**Deferred LV costs (to be included in 1586)**	**Acct 1508 Pension and OEB costs**	**Acct 1580 RSVA WMSC**	**Acct 1582 RSVA One Time**	**Acct 1584 RSVA Network**	**Acct 1586 RSVA Connection**	**Total April 30, 2006 Reg. Asset Variance Balance**
2	**Total Amount**	$40,236,797	$1,863,350	$26,523	$54,585	($4,563,015)	($16,697,635)	$20,920,604
3	**Embedded Distributor**	by Deferred LV costs	by Deferred LV costs	by WMSC kWh	by WMSC kWh	by Network kW	by connection kW	
4		by kWhs to customers	by Dx revenue to customers	by kWhs to customers	by kWhs to customers	by kWhs to customers	by kWhs to customers	
34	Hydro One Brampton Networks Inc.	$120,367	$5,574		$0	($24,213)	($89,616)	$12,113
35	Hydro Ottawa Limited	$2,397,664	$111,035	$2,802	$5,767	($198,408)	($729,404)	$1,589,456
36	Hydro Vaughan Distribution Inc.	$329,908	$15,278	$2,672	$5,500	($143,459)	($518,749)	-$308,850
37	Innisfil Hydro Distribution Systems Limited	$578,155	$26,774		$0	($73,773)	($269,868)	$261,288
38	Kingston Electricity Distribution Ltd.	$668,058	$30,937		$0	($113,034)	($407,836)	$178,125
39	Lakefield Distribution Inc.	$58,731	$2,720		$0	($10,158)	($36,668)	$14,625
40	Lakefront Utilities Inc.	$478,323	$22,151		$0	($78,149)	($281,654)	$140,671
41	Lakeland Power Distribution Ltd.	$1,359,319	$62,950	$5,002	$10,295	($67,320)	($244,338)	$1,125,908
42	London Hydro Inc.	$4,693	$217		$0	($854)	($3,078)	$979
43	Markham Hydro Distribution Inc.	$353,793	$16,384		$0	($52,129)	($189,637)	$128,411
44	Middlesex Power Distribution Corporation	$142,418	$6,595		$0	($14,014)	($50,843)	$84,157
45	Midland Power Utility Corporation	$717,838	$33,243		$0	($67,484)	($243,206)	$440,390
46	Milton Hydro Distribution Inc.	$226,685	$10,498		$0	($135,017)	($487,139)	-$384,974
47	Newbury Power Inc.	$32,029	$1,483	$89	$184	($1,166)	($4,201)	$28,418
48	Niagara Falls	$0	$0	$13	$28	($175)	($697)	-$831
49	Niagara-On-The-Lake Hydro Inc.	$837,451	$38,782		$0	($5,893)	($21,357)	$848,983
50	Norfolk Power Distribution Inc.	$1,041,259	$48,220		$0	($87,227)	($315,164)	$687,088
51	North Bay Hydro Distribution Ltd.	$26,001	$1,204		$0	($4,763)	($17,390)	$5,052
52	Northern Ontario Wires Inc.	$467,095	$21,631		$0	($6,932)	($25,039)	$456,755
53	Oakville Hydro Electricity Distribution Inc.	$839,982	$38,899		$0	($162,596)	($588,924)	$127,362
54	Orangeville Hydro Limited	$400,308	$18,538		$0	($68,404)	($246,950)	$103,492
55	Orillia Power Distribution Corporation	$417,184	$19,320		$0	($97,953)	($353,906)	-$15,355
56	Oshawa PUC Networks Inc.	$0	$0		$0	($573)	($2,088)	-$2,661
57	Ottawa River Power Corp. - Wires Corp.	$478,995	$22,182	$3,192	$6,569	($51,627)	($191,863)	$267,448
58	Parry Sound Power Corp.	$159,931	$7,406		$0	($26,068)	($93,975)	$47,294
59	Peninsula West Utilities Limited	$2,336,802	$108,216		$0	($43,829)	($158,780)	$2,242,410
60	Peterborough Distribution Inc.	$1,204,383	$55,775		$0	($80,160)	($292,892)	$887,105
61	Port Colborne Hydro Inc. [with Ft. Erie, is Can. Niagara Power]	$22,551	$1,044		$0	($3,714)	($24,581)	-$4,700
62	Renfrew Hydro Inc.	$181,463	$8,403	$1,982	$4,080	($26,413)	($95,154)	$74,362

APPENDIX 8-F

HYDRO ONE's PROPOSED REGULATORY ASSET CHARGES TO EMBEDDED DISTRIBUTORS FOR JAN. 2004 TO APR. 2006

	A	BX	BY	CA	CB	CC	CD	CE
1		**Deferred LV costs (to be included in 1586)**	**Acct 1508 Pension and OEB costs**	**Acct 1580 RSVA WMSC**	**Acct 1582 RSVA One Time**	**Acct 1584 RSVA Network**	**Acct 1586 RSVA Connection**	**Total April 30, 2006 Reg. Asset Variance Balance**
2	**Total Amount**	$40,236,797	$1,863,350	$26,523	$54,585	($4,563,015)	($16,697,635)	$20,920,604
3	**Embedded Distributor**	by Deferred LV costs	by Deferred LV costs	by WMSC kWh	by WMSC kWh	by Network kW	by connection kW	
4		by kWhs to customers	by Dx revenue to customers	by kWhs to customers	by kWhs to customers	by kWhs to customers	by kWhs to customers	
63	Richmond Hill Hydro	$529,808	$24,535		$0	($73,595)	($273,184)	$207,564
64	Rideau St. Lawrence Distribution Inc.	$340,649	$15,775		$0	($38,871)	($142,633)	$174,921
65	Wellington Electric Distribution Company Inc.	$29,913	$1,385		$0	($5,099)	($18,743)	$7,456
66	Sioux Lookout Hydro Inc.	$1,593,430	$73,791		$0	($28,373)	($102,216)	$1,536,631
67	Scugog Hydro Energy Corporation	$97,238	$4,503	$1,171	$2,410	($15,353)	($55,346)	$34,623
68	Tay Hydro Electric Distribution Company Inc.	$209,093	$9,683	$1,017	$2,093	($12,991)	($48,538)	$160,357
69	Terrace Bay Superior Wires Inc.	$182,775	$8,464		$0	($5,784)	($21,573)	$163,882
70	Toronto Hydro-Electric System Ltd.	$234,493	$10,859	$28	$57	($419)	($1,511)	$243,507
71	Veridian Connections Inc.	$2,511,918	$116,326	$3,305	$6,801	($405,523)	($1,484,677)	$748,150
72	Wasaga Distribution Inc.	$254,789	$11,799		$0	($31,618)	($119,803)	$115,167
73	Waterloo North Hydro Inc.	$58,900	$2,728		$0	($9,077)	($32,759)	$19,793
74	Wellington North Power Inc.	$169,191	$7,835		$0	($25,448)	($91,726)	$59,853
75	West Nipissing Energy Services Ltd.	$145,882	$6,756		$0	($18,139)	($65,847)	$68,652
76	West Perth Power Inc.	$133,540	$6,184		$0	($18,791)	($67,695)	$53,238
77	Westario Power Inc.	$1,139,301	$52,761		$0	($139,397)	($507,484)	$545,182
78	Whitby Hydro Electric Corporation	$619,122	$28,671		$0	($108,605)	($391,902)	$147,286
84	Eastern Ont. Power (formerly Granite Power Company)	$143,131	$6,628	$1,571	$3,234	($23,467)	($84,872)	$46,225
85	Hydro Quebec - Village of Des Joachims	$56,707	$2,626	$170	$350	($2,579)	($9,339)	$47,935
86	**Total Amount**	$40,236,796	$1,863,350	$26,523	$54,585	($4,563,015)	($16,697,635)	$20,920,604

CHAPTER 9 – COST ALLOCATION

9.0 Introduction

1. As directed in the DRH, THESL uses class distribution revenue shares derived from current rates (which are based on the initial rate design) to allocate the revenue requirement to customer classes.

9.1 Customer Classes

2. For rates effective May 1, 2006, THESL retains both the existing customer rate classes and customer classifications, as the currently approved rates. This is indicated in the attached completed Schedule 9-1: Customer Classification and Schedule 9-2: Customer Eligibility Criteria.

9.2 Determination of the Appropriate Share of the 2006 Revenue Requirement for Each Class, Sub-Class or Group

3. As previously noted, THESL has used an FTY approach as the cost basis for rates effective May 1, 2006. Therefore, the 2006 class revenue allocation uses a forecast number of customers for 2006 and a forecast 2006 consumption level to derive the overall class revenue consumption instead of the three-year average prescribed in the 2006 EDR Model and Schedule 9-3: Allocation Factors to Customer Classifications, for an HTY-based revenue calculation. Attached, as part of this Application is a completed Schedule 9-3 detailing the 2002 to 2004 statistical data required to determine the default allocation factors and indicating that

the default methodology (i.e., classifications for an HTY-based revenue calculation) is not used in the derivation of rates derived in this Application. Attached is Schedule 9-4: Non-Default Allocation Factors to Customer Classifications, that shows the 2006 forecast data used for cost allocation derivation.

9.2.1 Load Forecast Methodology

4. THESL has used a multiple regression econometric model to forecast total purchased kWh. Econometric regression techniques to forecast daily maximum kW demand, cost of power expense and the growth in THESL's customer base have produced mediocre results at best. Instead, for the process of forecasting demand determinants for this Application THESL has used time series regression modeling techniques.
5. The forecast of total purchased kWh is based on a single-equation multiple regression estimation and forecasting model. Independent or explanatory variables in the model are heating degree days ("HDD"; 10-year average over 1995-2004 based on data from Environment Canada), cooling degree days ("CDD"; 10-year average over 1995-2004 based on data from Environment Canada), peak hours per month, and the real GDP index for Ontario. The forecasting model uses a 2.5 percent annual GDP growth rate for 2005, and a 2.9 percent GDP growth rate for 2006, based on a consensus forecast from six Chartered banks.
6. THESL's forecast of monthly peak kW demand is based on historical monthly load factors from January 1997 to May 2005. Forecast load factors are applied to the monthly kWh forecast to derive THESL

system kW demands. THESL has used a Holt-Winters exponential smoothing model to forecast system load factors. THESL has found that this statistical method is particularly well suited to forecasting variables that display strong seasonal components.

7. THESL's system Cost of Power expense forecast is derived using a two-step process. First, as part of its shared services to THESL, THC subscribes to an energy price forecast service from its energy services company, THESI. This price forecast is applied to the energy forecast to derive the energy Cost of Power expense forecast.

8. Secondly, THESL uses historical average ratios between THESL Transmission System Line Connection kW and THESL system kW and between THESL Transmission System Transformer Connection kW and THESL system kW. These historical ratios are then applied to the THESL system kW forecast to derive Transmission System Line Connection and Transmission System Transformer Connection forecasts. Appropriate transmission rates from Hydro One are applied to the relevant transmission quantities to derive the transmission Cost of Power expense.

9. In addition to these 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 these services. Any applicable credits, such as switchgear credits, are also accounted for in the overall Cost of Power expense.

10. The overall 2006 Cost of Power expense is entered into the working capital calculation in the 2006 EDR Model.

11. Forecast retail billing determinants are derived from the purchased energy forecast. Distribution losses and specific supply losses are subtracted from the purchased energy forecast to arrive at the energy sales forecast. This energy sales forecast is apportioned to the various classes based on analysis of historical billing statistics. For the large general service customers, billing determinants for distribution charges are based on kVA units. The historical relationship between kVA / kWh is used to translate kWh into kVA for these customers.

12. Growth in THESL's customer base for 2006 is based on historical growth rates from January 2002 to May 2005, and the forecast is also based on a Holt-Winters time series exponential smoothing model. The growth in THESL's customer base is forecast to be 0.41 percent in 2005, and a further 0.44 percent in 2006.

13. THESL continues to develop and enhance its econometric and statistical models in an attempt to gain better statistical and predictive rigour. For example, for the purchased kWh forecast, several combinations of explanatory variables have been tested over the past few years, but the current set of explanatory variables gave the best statistical "fit" and subsequent forecast of purchased kWh for 2006.

14. Forecasts of purchased energy, THESL system kW and other variables are not simply based on a mechanistic application of the results of statistical models. Where appropriate, judgement is applied to address any statistical shortcomings of the various models. It is THESL's belief that it has applied a prudent mix of statistical rigour and judgement to

derive appropriate load, customer growth and cost of power expense forecasts for 2006.

15. Details of the forecast are attached as the following Appendices to this chapter:

Appendix 9-A	2006 kWh Regression Model Result
Appendix 9-B	10-year (1995-2004) Average HDD and CDD
Appendix 9-C	Economic Outlook: Annual Real Percent GDP Change from 6 Chartered Banks in Canada
Appendix 9-D	Estimate of 2006 Peak Hours
Appendix 9-E	2006 System Load Factor Forecast Model Result

9.3 Determination of the Appropriate Share of the 2006 CDM, Smart Meter, and Regulatory Asset Revenue Requirements

16. THESL is not seeking approval for any incremental CDM spending to funding previously approved by the Board.

17. As directed in the DRH, 2006 incremental revenue requirement associated with Smart Meter activities is allocated across all rate classes, sub-classes or groups based on their respective share of distribution revenue.

Schedule 9-1 Customer Classification

"X" indicates current and proposed customer classifications.

Customer Classification	Current	Proposed
Residential		
Regular	X	X
Time of Use	X	______
Urban	______	______
Suburban	______	______
Other (specify) ________________________	______	______
Other (specify) ________________________	______	______
Other (specify) ________________________	______	______
Other (specify) ________________________	______	______
Other (specify) ________________________	______	______
General Service		
Less than 50 kW	X	X
Less than 50 kW Time of Use	______	______
Other < 50 kW (specify) ________________	______	______
50 to 1000 kW - Non Interval	X	X
51 to 1000 kW - Interval	X	X
Other > 50 kW (specify) ________________	______	______
Other > 50 kW (specify) ________________	______	______
Other > 50 kW (specify) ________________	______	______
Intermediate Use	X	X
Large Use	X	X
Unmetered Scattered Load	X	X
Sentinel Lighting	______	______
Street Lighting	X	X
Back-up/Standby Power	X	X
Other (specify) ________________________	______	______
Other (specify) ________________________	______	______

Provide a detailed explanation and justification for each of the proposed changes to the classifications.

THESL requests Board approval to eliminate Residential Time of Use Rates, as there are currently no Residential customers on these approved rates.

SCHEDULE 9-2: CUSTOMER ELIGIBILITY CRITERIA

Customer Classification

Residential

Regular:
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.
Time of Use:

Urban:

Suburban:

Other (specify) ______________________________:

Other (specify) ______________________________:

Other (specify) ______________________________:

Other (specify) ______________________________:

Other (specify) ______________________________:

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.

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 than50 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 between 1000-5000 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 classification refers to a non-residential account whose monthly or forecast average peak demand is 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 refers to an account whose monthly average peak demand is equal to or greater than 5,000 kW, or is forecast to be equal to or greater than 5,000 kW.

<u>Unmetered Scattered Load:</u>
This classification refers to an account whose monthly average peak demand 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 customer will provide detailed manufacturer information/ documentation with regard to the connected load or consumption of the proposed unmetered load. The customer's billing consumption will be based on the consumption provided by manufacturer information/ documentation or based on the connected load times the hours use.

<u>Back-up/Standby Power:</u>
This classification refers to an account having backup power equal to or greater than 500 kW.

<u>Street Lighting:</u>
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by distribution switching system or photo cells. The consumption for these customers will be based on the product of the connected load and the number of hours that the lights are on as established in the approved OEB street lighting load shape template.

Schedule 9-3: Allocation Factors to Customer Classifications

A distributor must fill out this Schedule to provide the 2002, 2003 and 2004 statistical data required to determine the default allocation factors and to indicate acceptance or rejection of the default allocation methodology as outlined in Section 9.2.

For 2002

	2002 Customers (year end)	2002 kWh or kVA	2002 per Cust.
Residential			
Regular	586,714	5,641,748,572	9,616
Time of Use			
Urban			
Suburban			
General Service			
Less than 50 kW	67,274	2,650,721,405	39,402
Less than 50 kW Time of Use			
Greater than 50 kW	9,641	20,961,880	2,174
Greater than 50 kW Time of Use	886	4,541,144	5,128
Intermediate Use	482	12,034,150	24,967
Large Use	46	5,842,187	127,004
Unmetered Scattered Load (connection)	13,766	-	13,766
Unmetered Scattered Load (customer)	1,519	57,694,623	37,973
Sentinel Lighting			
Street Lighting	159,821	317,526	2
Back-up/Standby Power	5	120,550	24,110

In the 2006 EDR Model (Sheet 6-2) the Standby kVA is included in the Large Users kVA

Schedule 9-3: Allocation Factors to Customer Classifications

A distributor must fill out this Schedule to provide the 2002, 2003 and 2004 statistical data required to determine the default allocation factors and to indicate acceptance or rejection of the default allocation methodology as outlined in Section 9.2.

For 2003

	2003 Customers (year end)	2003 kWh or kVA	2003 per Cust.
Residential			
Regular	590,109	5,420,267,739	9,185
Time of Use			
Urban			
Suburban			
General Service			
Less than 50 kW	67,064	2,584,833,028	38,543
Other < 50 kW (specify)			
Greater than 50 kW	9,484	18,587,759	1,960
Greater than 50 kW Time of Use	1,424	7,236,307	5,082
Intermediate Use	497	11,863,247	23,870
Large Use	47	5,360,148	114,046
Unmetered Scattered Load (connect	13,094	-	13,094
Unmetered Scattered Load (custome	1,508	55,796,963	37,003
Sentinel Lighting			
Street Lighting	159,821	317,526	2
Back-up/Standby Power	5	120,550	24,110

In the 2006 EDR Model (Sheet 6-2) the Standby kVA is included in the Large Users kVA

Schedule 9-3: Allocation Factors to Customer Classifications

A distributor must fill out this Schedule to provide the 2002, 2003 and 2004 statistical data required to determine the default allocation factors and to indicate acceptance or rejection of the default allocation methodology as outlined in Section 9.2.

For 2004

	2004 Customers (year end)	2004 kWh or kVA	2004 per Cust.
Residential			
Regular	594,976	5,428,344,270	9,124
Time of Use	________	________	________
Urban	________	________	________
Suburban	________	________	________
General Service			
Less than 50 kW	66,505	2,548,012,246	38,313
Less than 50 kW Time of Use	________	________	________
Greater than 50 kW	9,621	17,798,349	1,850
Greater than 50 kW Time of Use	1,525	7,646,423	5,014
Intermediate Use	498	11,617,228	23,328
Large Use	47	5,409,480	115,095
Unmetered Scattered Load (connection)	14,450	-	14,450
Unmetered Scattered Load (customer)	1,557	55,842,609	35,859
Sentinel Lighting	________	________	________
Street Lighting	159,821	308,277	2
Back-up/Standby Power	5	120,550	24,110

In the 2006 EDR Model (Sheet 6-2) the Standby kVA is included in the Large Users kVA

Schedule 9-3: Allocation Factors to Customer Classifications

A distributor must fill out this Schedule to provide the 2002, 2003 and 2004 statistical data required to determine the default allocation factors and to indicate acceptance or rejection of the default allocation methodology as outlined in Section 9.2.

Average 2002 to 2004

		2002 - 2004 ave. per Cust.
Residential		
Regular		9,308
Time of Use		________
Urban		________
Suburban		________
General Service		
Less than 50 kW		38,753
Less than 50 kW Time of Use		________
Greater than 50 kW		1,995
Greater than 50 kW Time of Use		5,074
Intermediate Use		24,055
Large Use		118,715
Unmetered Scattered Load (connection)	________	13,770
Unmetered Scattered Load (customer)	________	36,945
Sentinel Lighting	________	________
Street Lighting	________	2
Back-up/Standby Power	________	120,550

The default methodology as outlined in Section 9.2 and incorporated in the Model is acceptable. Yes ______ No __X___

If no, the distributor is proposing to make changes to the methodology and/or the statistical data used to derive the per customer data (e.g. as a result of a Tier 1 adjustment) and must complete Schedule 9-4.

In the 2006 EDR Model (Sheet 6-2) the Standby kVA is included in the Large Users kVA

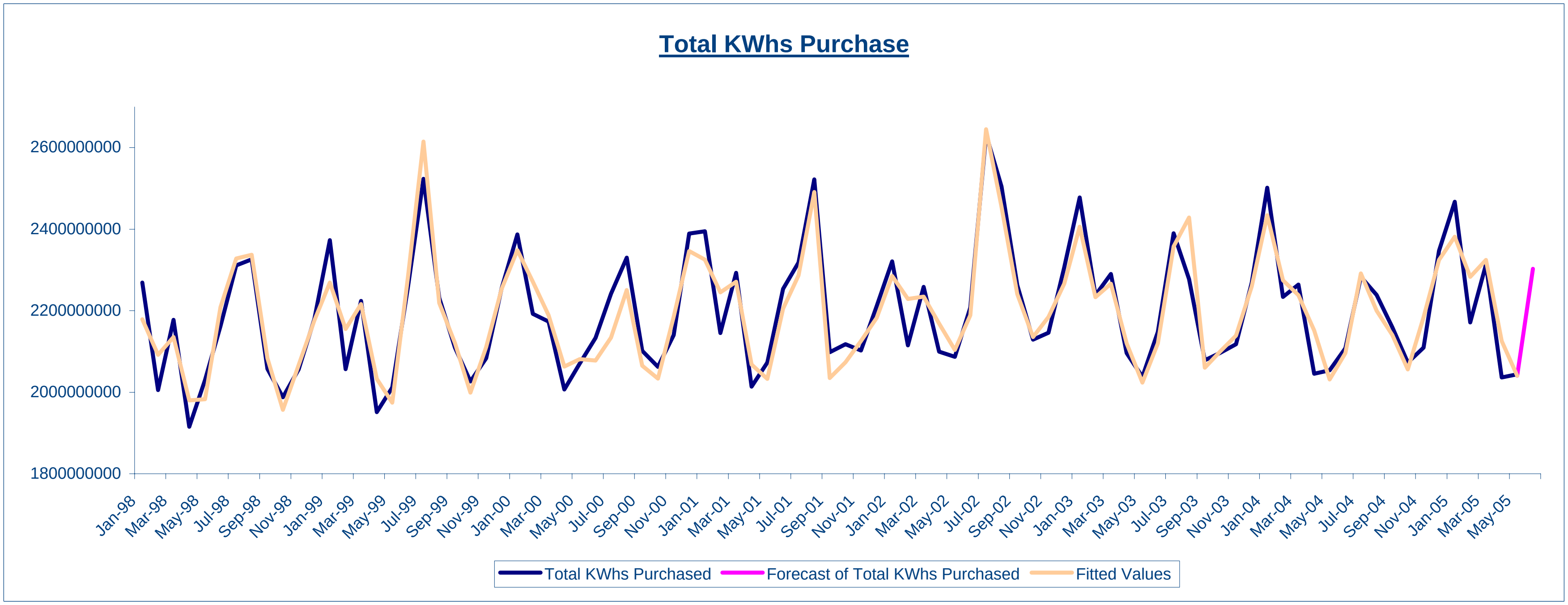
Schedule 9-4 Non-default Allocation Factors to Customer Classifications

	Customers	kWh or kVA	per Cust.
Residential			
Regular	597,210	5,470,966,591	9,161
Time of Use	________	___________	________
Urban	________	___________	________
Suburban	________	___________	________
General Service			
Less than 50 kW	66,505	2,620,609,508	39,405
Less than 50 kW Time of Use	________	___________	________
Greater than 50 kW	________	___________	________
Greater than 50 kW Non Interval	9,550	17,351,203	1,817
Greater than 50 kW Interval	1,682	8,472,217	5,037
Intermediate Use	511	11,825,404	23,142
Large Use	47	5,445,936	115,871
Unmetered Scattered Load - Charge per Connection	13,408	-	13,408
Unmetered Scattered Load - Admin Charge per Customer	1,438	54,396,775	37,823
Sentinel Lighting	________	___________	________
Street Lighting	159,861	317,526	2
Back-up/Standby Power	5	120,550	24,110

The following is the detailed explanation and justification for not using the default allocation factors as determined in Schedule 9-3.

Since THESL is using an FTY as a cost basis for rates effectve May 1, 2006, the non-default allocation factors are based on 2006 forecast data.

APPENDIX 9-A: 2006 kWh REGRESSION MODEL RESULTS



Multiple Regression -- Result Formula

Total KWhs Purchased = 982,114,737.93 + ((Peak Hrs.) * 1,201,849.50) + ((Ontario Real GDP Monthly Index) * 4,249,195.11) + ((Actual HDD) * 626,829.94) + ((Actual CDD) * 3,573,732.28)

Audit Trail -- ANOVA Table (Multiple Regression Selected)

Source of Variation	SS	df	MS	SEE
Regression	1,655,971,799,941,380,000.00	4	413,992,949,985,346,000.00	
Error	250,845,624,380,713,000.00	84	2,986,257,433,103,730.00	54,646,659.85
Total	1,906,817,424,322,100,000.00	88		

Audit Trail -- Coefficient Table (Multiple Regression Selected)

Series Description	Included in Model	Coefficient	Standard Error	T-test	P-value	F-test	Elasticity	Overall F-test
Total KWhs Purchas	Dependent	982,114,737.93	143,985,733.86	6.82	0.00	46.52		138.63
Peak Hrs.	Yes	1,201,849.50	317,972.70	3.78	0.00	14.29	0.18	
Ontario Real GDP Monthl	Yes	4,249,195.11	705,280.65	6.02	0.00	36.30	0.23	
Actual HDD	Yes	626,829.94	33,106.18	18.93	0.00	358.49	0.08	
Actual CDD	Yes	3,573,732.28	160,280.53	22.30	0.00	497.14	0.05	

Audit Trail -- Correlation Coefficient Table

Series Description	Included in Model	Total KWhs Purchased	Peak Hrs.	› Real GDP Monthl	Actual HDD	Actual CDD
Total KWhs Purchas	Dependent	1.00	0.12	0.18	0.18	0.49
Peak Hrs.	Yes	0.12	1.00	-0.11	-0.12	0.10
Ontario Real GDP Monthl	Yes	0.18	-0.11	1.00	0.08	-0.10
Actual HDD	Yes	0.18	-0.12	0.08	1.00	-0.70
Actual CDD	Yes	0.49	0.10	-0.10	-0.70	1.00

Audit Trail -- Coefficient Determination Table

Series Description	Included in Model	Total KWhs Purchased	Peak Hrs.	› Real GDP Monthl	Actual HDD	Actual CDD
Total KWhs Purchas	Dependent	1.00	0.02	0.03	0.03	0.24
Peak Hrs.	Yes	0.02	1.00	0.01	0.01	0.01
Ontario Real GDP Monthl	Yes	0.03	0.01	1.00	0.01	0.01
Actual HDD	Yes	0.03	0.01	0.01	1.00	0.49
Actual CDD	Yes	0.24	0.01	0.01	0.49	1.00

Audit Trail -- Covariance Table

Series Description	Included in Model	Total KWhs Purchased	Peak Hrs.	› Real GDP Monthl	Actual HDD	Actual CDD
Total KWhs Purchas	Dependent	21,668,379,821,842,000.00	337,845,719.12	224,262,162.65	6,719,871,599.15	3,706,676,994.76
Peak Hrs.	Yes	337,845,719.12	344.07	-16.30	-560.35	96.49
Ontario Real GDP Monthl	Yes	224,262,162.65	-16.30	69.53	156.15	-41.83
Actual HDD	Yes	6,719,871,599.15	-560.35	156.15	61,039.93	-8,823.23
Actual CDD	Yes	3,706,676,994.76	96.49	-41.83	-8,823.23	2,602.07

Audit Trail - Statistics

Accuracy Measures	Value
AIC	3,420.74
BIC	3,423.23
Mean Absolute Percentage Error (MAPE)	1.93%
Sum Squared Error (SSE)	250,845,624,380,713,000.00
R-Square	86.84%
Adjusted R-Square	86.22%
Chi-Square	1.00
Cochrane-Orcutt	-0.20
Mean Absolute Error	42,241,502.02
Mean Error	0.00
Mean Square Error	2,818,490,161,581,040.00
Normality Error	9.71
Root Mean Square Error	53,089,454.33
Standard Deviation of Error	53,390,246.85
Theil	0.30

Method Statistics	Value
Method Selected	Multiple Regression

Forecast Statistics	Value
Durbin Watson	2.37
Mean	2,195,393,732.91
Median	2,171,472,018.90
Standard Deviation	147,201,833.62
Variance	21,668,379,821,842,000.00
Skewness	0.65
Kurtosis	2.97
Max	2,632,596,359.53
Min	1,915,449,782.50
Mean Absolute Deviation	120,908,375.53
Sum Squared Deviation	1,906,817,424,322,100,000.00
Mean Square Deviation	21,424,914,880,023,600.00
Mode	0.00
Range	717,146,577.03
Root Mean Square	146,372,520.92
Auto-Correlation	0.29
Auto-Covariance	6,262,223,443,966,530.00
Coefficient of Variation	6.71
Ljung-Box	33.11

APPENDIX 9-B: 10-YEAR (1995-2004) AVERAGE HDD AND CDD

	1	2	3	4	5	6	7	8	9	10		
HDD	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total	Average
Jan	653.2	765.2	756.6	580.3	694	738.9	684.9	572.2	814.6	804.2	7064.1	706.41
Feb	707	689.8	593	465.2	507.5	612.7	587.5	540.2	699	586.5	5988.4	598.84
Mar	498.1	645.6	600	453.1	508.1	418.6	566.6	545.6	581.1	459.1	5275.9	527.59
Apr	417.6	408.2	366.8	245.4	271.8	339.2	293.8	329.5	351.2	317.2	3340.7	334.07
May	149.2	205.9	260.8	42.3	72.9	139.6	111.5	227.5	154.2	158.9	1522.8	152.28
Jun												0
Jul												0
Aug												0
Sep	133.7	71.6	87.1	23	31.1	99.5	73.6	21.8	36.5	0	577.9	57.79
Oct	219.4	273.1	266.9	180.7	223.1	212.7	232.5	292.2	247	203.2	2350.8	235.08
Nov	511.4	512.1	466.5	351.1	335.4	432	324.5	445	368.4	351.8	4098.2	409.82
Dec	717.5	571.6	586.2	488	528.9	780.3	505	619.4	527.1	605.7	5929.7	592.97
Total	4007.1	4143.1	3983.9	2829.1	3172.8	3773.5	3379.9	3593.4	3779.1	3486.6	36148.5	3614.85

	1	2	3	4	5	6	7	8	9	10		
CDD	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	Total	Average
Jan											0	0
Feb											0	0
Mar											0	0
Apr											0	0
May	3.5	8.6	0	41.2	22.8	23.7	12.2	7.8	0	11.7	131.5	13.15
Jun	77.9	38.3	73.2	92.8	107.8	41.1	79.7	70	55.5	33.2	669.5	66.95
Jul	130.9	59.6	103	133.1	208	71.8	100.9	192.4	115.4	70.6	1185.7	118.57
Aug	122.9	87.1	46.8	145.6	96	92.5	160	142.7	146.4	70.8	1110.8	111.08
Sep	12.7	27.1	11.7	64.5	63.2	35.2	35.7	87.6	31.8	42.1	411.6	41.16
Oct											0	0
Nov											0	0
Dec											0	0
Total	347.9	220.7	234.7	477.2	497.8	264.3	388.5	500.5	349.1	228.4	3509.1	350.91

APPENDIX 9-C: ECONOMIC OUTLOOK - ANNUAL REAL GDP INCREASE RATE PERCENT FROM SIX CHARTERED BANKS IN CANADA

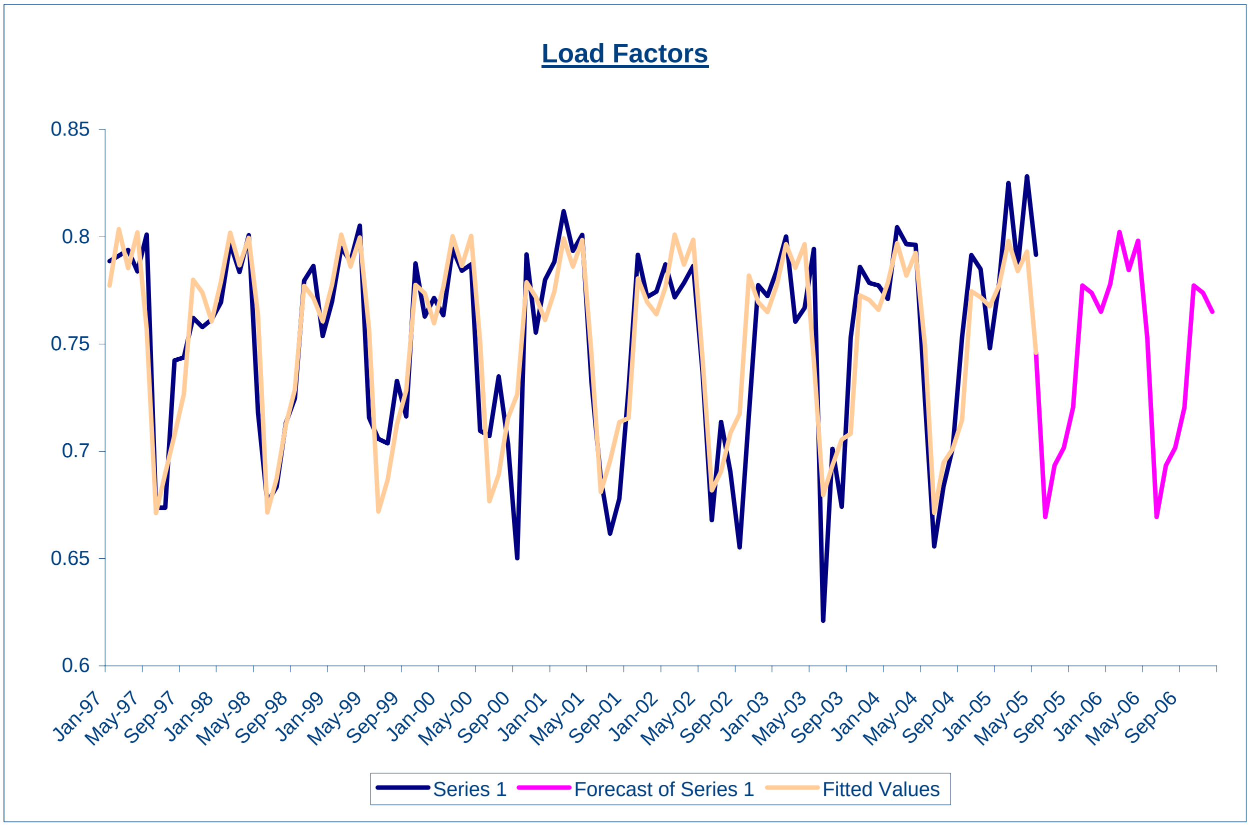
	BMO	TD	CIBC	Scotia Bank	RBC	National Bank	Annual AVG	Monthly %
2005	2.7	2.2	2.2	2.2	2.4	3	2.45	0.2042
2006	3.6	3.2	2.8	2	3	N/A	2.92	0.2433

APPENDIX 9-D: ESTIMATE OF 2006 PEAK HOURS

16 peak hours / working day

	No. of working days (excl. weekend and public holiday)	Total peak hours	(- public holiday)
Aug-03	20	320	-1
Sep-03	21	336	-1
Oct-03	22	352	-1
Nov-03	20	320	0
Dec-03	21	336	-2
Jan-04	21	336	-1
Feb-04	20	320	0
Mar-04	22	352	-1
Apr-04	22	352	0
May-04	19	304	-2
Jun-04	22	352	0
Jul-04	21	336	-1
Aug-04	21	336	-1
Sep-04	21	336	-1
Oct-04	20	320	-1
Nov-04	22	352	0
Dec-04	21	336	-2
Jan-05	20	320	-1
Feb-05	20	320	0
Mar-05	22	352	-1
Apr-05	21	336	0
May-05	20	320	-2
Jun-05	22	352	0
Jul-05	20	320	-1
Aug-05	22	352	-1
Sep-05	21	336	-1
Oct-05	20	320	-1
Nov-05	22	352	0
Dec-05	20	320	-2
Jan-06	**21**	**336**	**-1**
Feb-06	**20**	**320**	**0**
Mar-06	**22**	**352**	**-1**
Apr-06	**20**	**320**	**0**
May-06	**21**	**336**	**-2**
Jun-06	**22**	**352**	**0**
Jul-06	**20**	**320**	**-1**
Aug-06	**22**	**352**	**-1**
Sep-06	**20**	**320**	**-1**
Oct-06	**21**	**336**	**-1**
Nov-06	**22**	**352**	**0**
Dec-06	**19**	**304**	**-2**

APPENDIX 9-E: 2006 SYSTEM LOAD FACTOR FORECAST MODEL RESULT



Forecast -- Holt-Winters Selected

Date	Monthly
Jun-2005	0.67
Jul-2005	0.69
Aug-2005	0.70
Sep-2005	0.72
Oct-2005	0.78
Nov-2005	0.77
Dec-2005	0.77
Jan-2006	0.78
Feb-2006	0.80
Mar-2006	0.78
Apr-2006	0.80
May-2006	0.75
Jun-2006	0.67
Jul-2006	0.69
Aug-2006	0.70
Sep-2006	0.72
Oct-2006	0.78
Nov-2006	0.77
Dec-2006	0.77
Avg	0.74
Max	0.80
Min	0.67

Audit Trail - Statistics

Accuracy Measures	Value
AIC	-463.99
BIC	-456.14
Mean Absolute Percentage Error (MAPE)	2.39%
Sum Squared Error (SSE)	0.06
R-Square	73.70%
Adjusted R-Square	73.16%

Forecast Statistics	Value
Durbin Watson	1.96
Mean	0.75
Median	0.77
Standard Deviation	0.05
Variance	0.00

Method Statistics	Value
Method Selected	Holt-Winters

$A_i = \alpha\,(Y_i - C_{i-p}) + (1-\alpha)\,(A_{i-1} + B_{i-1})$ (level equation)

$B_i = \beta\,(A_i - A_{i-1}) + (1-\beta)\,B_{i-1}$ (trend equation)

$C_i = \gamma\,(Y_i - A_{i-1} - B_{i-1}) + (1-\gamma)\,C_{i-p}$ (seasonal index equation)

The h steps ahead prediction: $Y_{n+h} = A_n + h\,B_n + C_{n+h-p}$

Alpha	0.0026
Beta	0.1410
Gamma	0.0000
Decomposition Type	Additive

Seasonal Indices	Value
Index 1	0.0274
Index 2	0.0517
Index 3	0.0340
Index 4	0.0477
Index 5	0.0020
Index 6	-0.0811
Index 7	-0.0571
Index 8	-0.0488
Index 9	-0.0300
Index 10	0.0268
Index 11	0.0235
Index 12	0.0146

CHAPTER 10 — RATES AND CHARGES

10.0 Introduction

1. Although many elements of the Board's 2006 EDR Model are retained, some fundamental changes are necessary to perform an FTY cost-based rate derivation.

Financial Section Modifications

2. All references to 2002, 2003 and 2004 have been changed to 2004, 2005 and 2006, respectively. These changes affect many sections of the 2006 EDR Model, and are described in some detail below. Additionally, a forecast 2006 cost of power operating expense is used instead of an average historical cost of power and THESL has forecasted 2006 load as described in Chapter 9 of this Application. In Section 5 of the 2006 EDR Model, specific distribution expense classifications are modified to accommodate 2004, 2005 and 2006 as the relevant years for the Board's review.

Rates Section Modifications

3. All references to 2002, 2003 and 2004 are changed to 2004, 2005 and 2006, respectively in the rates section of the 2006 EDR Model.
4. THESL's volumetric rate for customers with demand meters is based on a kVA measurement methodology. Accordingly, all kW references in the 2006 EDR Model that do not specifically tie into equations are changed

to kVA measurements. To maintain the integrity of the 2006 EDR Model all equations that are based on kW have been left intact even though kVA is the rate determinant for THESL.

5. The billing for THESL's current Board-approved fixed customer charges and demand charges is based on a 30-day calculation instead of a calendar month. THESL has modified the 2006 EDR Model to accommodate the 30-day rate in both the distribution rates and rate riders.

6. The rate rider calculation in EDR Model worksheet 8-4 is modified to include rate riders for the OEB Fees and OMERS Pension deferral accounts, 2004 RSVA, and Hydro One LV Charges. Attached, as part of this Application is Appendix 10-A that details the OEB and OMERS Pension deferral account rate rider calculation.

7. In EDR Model worksheet 7- 1, THESL modifies both the calculated kWh and kVA per customer to use forecast 2006 customer class consumption instead of the 2002 to 2004 three-year average.

10.1 Fixed/Variable Split

8. While the methodology for developing the fixed/variable split is retained in the 2006 EDR Model, THESL's FTY-based rates use 2006 determinant estimates to develop the split instead of 2004 test year statistics. Attached, as part of this Application is a completed Schedule 10-1: Determination of the Fixed/Variable Splits, that identifies these determinants.

10.2 Unmetered Scattered Loads

9. Currently, THESL has a unique level of monthly customer charge based on number-of-customers and number-of-connections. In accordance with Section 10.2 of the DRH, which provides that distributors that have unique levels of charges for unmetered scattered loads are to maintain the *status quo* for 2006, THESL will maintain this basis for the monthly customer charge. Attached, as part of this Application is a completed Schedule 10-2: Unmetered Scattered Loads, that identifies 2002-2004 billing statistics.

10.3 Time of Use Distribution Rates

10. While there are OEB-approved residential Time of Use distribution rates as shown in the rates schedule (Schedule 2-4), there are currently no residential Time of Use customers on these approved rates. Therefore, THESL requests Board approval to eliminate these rates for the 2006 rate year.

11. As a house-keeping matter, THESL hereby informs the Board of its intention to re-name the General Service 50-1000 kW Time of Use Rates to General Service 50-1000 kW with Interval Meters as indicated on the attached Schedule 10-3: Time of Use Distribution Rates.

10.4 Transformer Allowance

12. As per the DRH, THESL hereby informs the Board that it will continue to apply the current levels of allowance for transformer ownership. Attached, as part of this Application is a completed Schedule 10-4 that

provides relevant transformer ownership allowance data.

10.5 Update of Loss Adjustment Factor Reflecting System Losses Including Unaccounted-for-Energy

13. In April 2000, THESL filed an application that unbundled rates. As part of application RP-2000-0021, THESL determined the loss adjustment factors for the system, large user class and other customer classes. Based on five-year consumption data between 1995 and 1999, THESL's distribution system loss adjustment factor was determined to be 1.0311 (detail shown in Appendix 10-B).

14. As part of RP-2000-0021, THESL submitted a report entitled "Toronto Hydro Electrical Losses of Large Customers" that estimated the distribution line loss percentage for large users to be 0.41 percent. The report is attached as part of this Application as Appendix 10-C.

15. THESL did not conduct a transformer loss study, but instead adopted the default value of 1 percent transformer losses for the large users. As a result, the total distribution losses for large users, including line losses and transformer losses were set at 1.41 percent (or a distribution loss factor of 1.0141). The distribution loss adjustment factor for the other retail customers was determined to be 1.033. These loss adjustment factors were submitted and approved by the OEB in RP-2000-0021.

16. In keeping with this methodology, these loss adjustment factors have been applied to the metered consumption of the respective customer classes in order to derive the billed consumption for energy and wholesale market service charges.

17. Attached is Schedule 10-5: Determination of Loss Adjustment Factors. Several observations and notes regarding the development of this schedule are contained in the following paragraphs.

18. THESL notes that the wholesale and retail consumption values are different from the values reported in the PBR filed data. In THESL's PBR filing, wholesale kWh reflects the purchased kWh from the IESO-administered market that includes the specific supply loss factor ("SSLF") of 1.0045. In Schedule 10-5, the SSLF is removed from the purchased kWh (Row A1) to yield the wholesale kWh (Row A).

19. For large use customers, the wholesale kWh (B) equals the retail kWh (C) times 1.0141 (the distribution loss adjustment factor for large use customers).

20. In THESL's PBR filing, retail consumption reflects actual metered kWh of the retail customers. However, some of THESL's customers are served at 13.8 kV or higher voltages and are metered on the high voltage side of the transformers (i.e., they are primary metered customers). This is not consistent with the majority of customers that are serviced at voltages that have been stepped down by system-owned or customer-owned transformers and are metered on the low voltage side of the transformer (i.e., they are secondary metered customers). The meter readings for primary metered customers therefore include the transformer losses while meter reading for secondary metered customers do not include transformer losses. In order to determine true distribution losses, it is then necessary to subtract the transformer losses of primary metered customers from their metered kWh. The primary

metered adjustments for 2003 and 2004 are shown in Schedule 10-5.

21. THESL's analysis shows that the average system loss adjustment factor over 2003 and 2004 is 1.031. Furthermore, THESL finds that, currently, there is insufficient information to allow a detailed analysis of the 2002 actual metered kWh because of the change in the billing system platform in 2002 pursuant to market opening. Accordingly, THESL continues to use the approved loss adjustment factors that were used in the 2002 analysis. THESL concludes that in light of the consistencies between the 2003 and 2004 loss adjustment factors, the system loss adjustment factor for 2002 is also assumed to be 1.031.

22. THESL further notes that the calculation of the distribution loss adjustment factors for 2002, 2003 and 2004, as well as the three-year average as shown in Schedule 10-5, remains the same as the currently approved load adjustment factors. Accordingly, THESL submits that it is not necessary to record the variance stemming from distribution system losses.

10.6 Standby Charges

23. THESL's current standby charges represent a collection of charges that have been grandfathered from the previous Metropolitan Toronto Area distribution utilities: Toronto Hydro; North York Hydro; Etobicoke Hydro; and York Hydro.

24. These are the only rates that have yet to be harmonized as a result of the amalgamation of the six utilities in 1998.

25. An application was submitted to the Board in 2002 to harmonize these

rates, but a review and decision into that application was cancelled as a result of Bill 210. Accordingly, for rates effective May 1, 2006, THESL hereby requests approval of the proposed standby charge derivation methodology presented as Appendix 10-D as part of this Application.

26. The Standby Facilities Charge is intended to recover the cost of providing reserve capacity to customers that have independent generation facilities. From a distribution system operation perspective, THESL believes that there is no discernible difference in distribution capacity line requirements supplying firm and standby power. THESL normally installs distribution capacity to carry total estimated load and recovers the associated costs through rates when the customer uses electricity. If the customer requires additional distribution capacity on a standby basis, the costs of capital, operations and maintenance, taxes and administration to provide that capacity are not recovered in the standard rates, since the standard rates are based on the assumption of continuous use, notwithstanding the continued financial burden to THESL. A separate standby charge is required so that the cost burden does not fall on general ratepayers. However, since there is no difference between firm and standby power from a distribution cost perspective, THESL proposes to charge the same rate to both types of customers.

27. THESL's standby proposal allows the customer and THESL to negotiate the amount of back-up line capacity that they wish to contract for. The contract backup demand can be determined by using either the full nameplate rating of the generator, or a portion of that value.

THESL will give consideration to factors such as the customer agreeing to shed load instead of taking power from the grid, and agreeing to displace load, when negotiating the backup amount. If a customer determines that no backup capacity is required, then that capacity will be available for use by other customers. In this case, THESL will not require the customer to pay standby facilities charges. However, the customer will not be entitled to rely upon the additional line capacity from THESL if its generator fails. THESL will require any customer operating parallel generation with a nameplate capacity of 500 kVA to sign a standby facilities contract regardless of the amount of backup line capacity contracted for.

28. Subject to arrangements made between the customer and the distributor with respect to outages (for maintenance, as an example), in every month when the customer does not require emergency power (i.e. generator does not go down), THESL will apply its regular distribution volumetric rate to the agreed-upon contracted standby demand (typically, the name plate rating of the load displacement facility) in addition to the customer's regular billing demand.

29. The backup overrun adjustment is to ensure customers contract for the appropriate amount of standby capacity. Backup overrun adjustments are determined by reviewing interval data prior to and immediately after a generator change of status. The instantaneous demand difference with the generator on and off is determinative of the standby line capacity used and any overrun. The backup overrun adjustments never exceed the nameplate rating of the generating plant; consequently the backup

overrun adjustment only applies to customers that have contracted for backup demand that is less than the generator nameplate rating.

30. Contract backup demand is reviewed on a quarterly basis. If a customer exceeds the contract backup demand (backup overrun adjustment) in any of the three preceding billing periods, the contract backup demand will be increased retroactively to the highest monthly level of utilization that occurred in those three months and the standby facility contract will be amended to reflect that level as the default contract backup demand. The backup overrun adjustment is assessed at the same rate as the billed backup demand.

31. The revenue from the current standby facilities rates is reported as customer and distribution charges.

32. Additionally, to avoid the double counting of distribution costs, for times when THESL will supply electricity that would normally be supplied by the load displacement facility, the proposal is to waive the standby charge, and bill the customer on its metered demand.

33. THESL proposes to recover the monthly incremental metering, billing and monitoring costs that are estimated to be incurred by the standby customers, via a monthly administration charge of $200, as shown in Appendix 10-E. In order to maintain the overall class revenue requirement, standby contract quantities are included in the appropriate class billing quantities.

34. THESL has developed its own standby charge methodology because it believes that it is impractical to apply different rates for different customers. This is the main implication that stems from the Board's

methodology of basing standby charges using a site-specific methodology. Due to the nature of THESL's distribution system and the expected locations of embedded generators, site-specific standby charges are impractical. THESL notes that, typically, generators are installed in dense urban environments and it would be difficult to assess how specific assets relate to each site and to each customer. For this reason, THESL finds it impractical to use site-specific standby rates for each customer, and instead THESL requests Board approval for its proposed standby charge methodology. Accordingly, Schedule 10-6 is not applicable and is not included as part of this Application.

10.7 Recovery of Low Voltage Charges Effective May 1, 2006

35. THESL has conformed to the requirements of the 2006 EDR Model by making an adjustment to the volumetric distribution rates for amounts associated with Hydro One's LV Charges effective May 1, 2006. THESL's LV Charges effective May 1, 2006 are based on the average LV costs over the January 2004 through April 2006 period. Since the total LV costs over this 28-month period have been determined to be $243,507, the average monthly cost is proposed to be set at $8,696.68 (i.e. $243,507/28 months). By continuing to apply this average, the LV Charge is estimated to be $104,360.16 (i.e. $8,696.68 * 12 months).

36. Since THESL is not a host distributor, Schedule 10-7 is not applicable and has not been included as part of this Application.

10.8 Demand Determinants

37. THESL continues its practices of determining the volumetric distribution charges for the general service customers based on 100% of the kVA demand.

10.9 Recovery of CDM, Smart Meter, and Regulatory Asset Revenue Requirements

38. THESL is not applying for any incremental CDM expenses or regulatory asset recovery.

39. Smart meter expenditures are recovered through base rates.

40. THESL is applying for a new rate rider to recover the two deferral accounts that collect incremental regulatory costs, OEB fees and OMERS pension deferral accounts, 2004 RSVA and Hydro One LV Charges, as discussed in Chapter 8.

SCHEDULE 10-1: DETERMINATION OF THE FIXED / VARIABLE SPLITS

The Model will establish the respective fixed/variable splits for each class, sub-class or group using the methodology outlined in the handbook. This Schedule is to be used if the distributor proposes to make any changes to the effective splits.

The distributor must provide the data in the following listing, together with a detailed explanation and justification at the end of this Schedule.

	Determined by Model		As Proposed	
Customer Classification	Fixed	Variable	Fixed	Variable
Residential				
Regular	50.42%	49.58%	50.82%	49.18%
Time of Use	_____	_____	_____	_____
Urban	_____	_____	_____	_____
Suburban	_____	_____	_____	_____
General Service				
Less than 50 kW	21.45%	78.55%	21.17%	78.83%
Less than 50 kW Time of Use	_____	_____	_____	_____
50 to 1000 kW - Non Interval	2.99%	97.01%	3.28%	96.72%
50 to 1000 kW - Interval	1.21%	98.79%	1.22%	98.78%
Intermediate Use	7.92%	92.08%	8.21%	91.79%
Large Use	7.28%	92.72%	7.30%	92.70%
Unmetered Scattered Load	3.52%	96.48%	3.44%	96.56%
Sentinel Lighting	_____	_____	_____	_____
Street Lighting	30.27%	69.73%	30.07%	69.93%
Back-up/Standby Power	_____	_____	_____	_____

The following is the detailed explanation and justification for not using the fixed/ variable splits as determined in the Model.

FTY based rates are derived with fixed / variable split based on FTY deteminants.

SCHEDULE 10-2: UNMETERED SCATTERED LOADS

1) Currently, the monthly service charge to unmetered scattered load customers having multiple unmetered connection points is on a per customer and not a per connection point basis and the level of the charge is equal to or less than the General Service <50 kW monthly service charge per customer.

Yes ____
No ____

2) Currently, there is an unique level of monthly service charge(s) payable by unmetered scattered loads.

Yes X (THESL has charges by customer and by connection.)
No ____

If the response is yes to either question 1 or 2, the distributor will maintain the status quo in its 2006 rate treatment of unmetered scattered loads, otherwise the distributor will fill in the following table and the rates will be established by the Model, as outlined in point 2 of section 10.2. The Model will also calculate the revenue shortfall and allocate it according to point 3 of section 10.2.

	Customers	Connections	kWh
2002 Unmetered Scattered Load	1,519	13,766	57,694,623
2003 Unmetered Scattered Load	1,508	13,094	55,796,963
2004 Unmetered Scattered Load	1,557	14,450	55,842,609
Average Unmetered Scattered Load	1,528	13,770	56,444,732

SCHEDULE 10-3: TIME OF USE DISTRIBUTION RATES

A distributor that currently has a sub-classification(s) entitled "Time of Use" must complete this Schedule to indicate that it proposes either to maintain the existing methodology to determine a separate set of distribution rates associated with this sub-classification or to harmonize the distribution rates with the equivalent non time of use sub-classification. In choosing the latter option, a distributor may retain the Time of Use sub-classification for statistical or other purposes.

This distributor currently has a sub-classification(s) entitled "Interval Meter".

Yes X
No ____

This distributor proposes to maintain the existing methodology to determine a separate set of distribution rates associated with the "Interval Meter" sub-classification(s).

Yes X

OR

This distributor proposes to harmonize the distribution rates with the equivalent non time of use sub-classification. In choosing this option the distributor may retain the Time of Use sub-classification for statistical or other purposes.

Yes ____

The following is a detailed explanation and justification of the proposed harmonization methodology, including an implementation plan. In addition, the Impact Analysis part of the Model has been modified to include sufficient bill comparisons to reflect this harmonization.

SCHEDULE 10-4: TRANSFORMER OWNERSHIP ALLOWANCE

2002	**kVA**	**$**
General Service		
50-1000 kW Non Interval Meter	3,827,941	$ (2,406,286.11)
50-1000 kW Interval Meter	1,238,022	$ (778,234.49)
Intermediate Use	9,145,954	$ (5,749,248.40)
Large Use	5,550,077	$ (3,488,840.28)

2003	**kVA**	**$**
General Service		
50-1000 kW Non Interval Meter	3,197,095	$ (2,009,729.13)
50-1000 kW Interval Meter	2,011,693	$ (1,264,572.73)
Intermediate Use	8,933,025	$ (5,615,398.81)
Large Use	5,108,221	$ (3,211,084.37)

2004	**kVA**	**$**
General Service		
50-1000 kW Non Interval Meter	2,800,155	$ (1,760,208.84)
50-1000 kW Interval Meter	2,201,336	$ (1,383,784.14)
Intermediate Use	8,848,600	$ (5,562,328.36)
Large Use	5,161,143	$ (3,244,351.90)

SCHEDULE 10-5: DETERMINATION OF LOSS ADJUSTMENT FACTORS

		2002	2003	2004	
A1	Purchased kWh including SSLF 1.0045 *Note 1	27,070,380,307	26,517,052,119	26,417,144,859	
A	"Wholesale" kWh (IESO) excluding SSLF 1.0045	26,988,506,740	26,398,259,950	26,298,800,257	
B	"Wholesale" kWh for Large Use Customers (IESO)	2,895,256,240	2,601,252,812	2,632,912,247	
C	Net "Wholesale" kWh (A)-(B)	24,093,250,500	23,797,007,138	23,665,888,011	
D	"Retail" kWh (Distributor)	26,177,019,147	25,610,311,515	25,501,220,986	* Note 2
E	"Retail" kWh for Large Use Customers (1.41% losses)	2,855,000,730	2,565,085,112	2,596,304,355	
F	Net "Retail" kWh (D)-(E)	23,322,018,417	23,045,226,403	22,904,916,631	
G	Distribution Loss Factor for customers other than Large Users [(C)/(F)]	1.0331	1.0326	1.0332	
H	**Distribution Loss Factor for customers other than Large Users (3-year average)**			**1.0330**	
I	Distribution Loss Factor for all customers including Large Users [(A)/(D)]	1.0310	1.0308	1.0313	
J	**Distribution Loss Adjustment Factor for all customers including Large Users (3-year average)**			**1.0310**	

Note 1:

Specific Supply Loss Factor (SSLF) was applied to THESL's wholesale meter consumption from from May-Dec 2002.

Before May 2002, no SSLF was applied to wholesale meter consumption because it was included in the

Ontario Hydro wholesale rates that are charged to LDC.

Note 2: Primary metering adjustment
2003 Adjustment

"ACTUAL" metered kWh	25,667,706,585
kWh adjustment due to primary adjustment	57,395,070
Actual without primary metering (Retail kWh)	25,610,311,515

2004 adjustment

"ACTUAL" metered kWh	25,558,066,373
kWh adjustment due to primary adjustment	56,845,387
Actual without primary metering (Retail kWh)	25,501,220,986

APPENDIX 10-A: DERIVATION OF INCREMENTAL RATE RIDERS FOR OEB FEES AND PENSION COST DEFERRAL, 2004 RSVA, AND HYDRO ONE LV CHARGES

	RESIDENTIAL	GS < 50 kW	GS - 50 to 1000 kW - Non Interval	GS - 50 to 1000 kW - Interval	GS > 1000 to 5000 kW	LARGE USER	SMALL SCATTER LOAD	STREETLIGHT	TOTAL
	A	B	C	D	E	F		G	H
2006 Forecast Data by Class									
kVA	N/A	N/A	17,351,203	8,472,217	11,825,404	5,566,486	N/A	317,526	**43,532,837**
kWh (Loss Adjusted)	5,470,966,591	2,620,609,508	6,174,749,298	3,667,466,273	5,080,177,986	2,605,123,574	54,396,775	108,994,196	**25,782,484,200**
Number of Customers	597,210	66,505	9,550	1,682	511	47	1,438	159,861	**836,804**
Distribution Revenue (Includes Transformer Allowance - Schedule 7-1 (2006 EDR Model)	*180,412,212*	*64,601,765*	*95,439,509*	*45,485,770*	*57,151,828*	*22,735,761*	*1,112,070*	*1,740,929*	**468,679,843**
Allocator's									
Energy Consumed - kWhs	21.22%	10.16%	23.95%	14.22%	19.70%	10.10%	0.21%	0.42%	**100.0%**
Number of Customers (Decision 7.0.67)	71.37%	7.95%	1.14%	0.20%	0.06%	0.01%	0.17%	19.10%	**100.0%**
Distribution Revenue	38.49%	13.78%	20.36%	9.71%	12.19%	4.85%	0.24%	0.37%	**100.0%**

		ALLOCATOR	RESIDENTIAL	GS < 50 kW	GS - 50 to 1000 kW - Non Interval	GS - 50 to 1000 kW - Interval	GS > 1000 to 5000 kW	LARGE USER	SMALL SCATTER LOAD	STREETLIGHT	TOTAL
OEB Defer Fees (Jul 04- Apr 06)	$5,007,299	**by 2006 Distribution Revenue**	$1,927,495	$690,195	$1,019,660	$485,963	$610,601	$242,905	$11,881	$18,600	**$5,007,299**
OMERS Defer Accounts(Jan 05 - Apr 06)	$7,258,248	**by 2006 Distribution Revenue**	$2,793,968	$1,000,460	$1,478,032	$704,419	$885,086	$352,099	$17,222	$26,961	**$7,258,248**
Hydro One - LV Charges (Jan 04 - Apr 06)	$243,507	**By kWH**	$51,671	$24,751	$58,318	$34,638	$47,981	$24,605	$514	$1,029	**$243,507**
RSVA - WMS (Jan 04 - Dec 04)	$1,252,063	**By kWH**	$265,684	$127,263	$299,862	$178,102	$246,706	$126,511	$2,642	$5,293	**$1,252,063**
RSVA - One Time (Jan 04 - Dec 04)	$1,637,788	**By kWH**	$347,534	$166,470	$392,240	$232,969	$322,710	$165,486	$3,455	$6,924	**$1,637,788**
RSVA -NW (Jan 04 - Dec 04)	($995,440)	**By kWH**	($211,229)	($101,180)	($238,402)	($141,598)	($196,141)	($100,582)	($2,100)	($4,208)	**($995,440)**
RSVA - CN (Jan 04 - Dec 04)	($5,669,183)	**By kWH**	($1,202,984)	($576,233)	($1,357,735)	($806,421)	($1,117,055)	($572,828)	($11,961)	($23,966)	**($5,669,183)**
RSVA - PW (Jan 04 - Dec 04)	($96,794)	**By kWH**	($20,539)	($9,838)	($23,182)	($13,769)	($19,072)	($9,780)	($204)	($409)	**($96,794)**
Subtotal	**$8,637,488**		$3,951,599	$1,321,888	$1,628,793	$674,303	$780,815	$228,417	$21,449	$30,223	**$8,637,488**
Adjustment for 23 Months Recovery (to Co-incide with the current Regulatory Assets recovery period)	**$9,013,031**		**$4,123,408**	**$1,379,362**	**$1,699,611**	**$703,621**	**$814,763**	**$238,348**	**$22,381**	**$31,537**	**$9,013,031**
Adjusted Amount to be Collected	**$9,013,031**		$4,123,408	$1,379,362	$1,699,611	$703,621	$814,763	$238,348	$22,381	$31,537	**$9,013,031**
To be allocoated Each Year for 23 Month (Till March 08)	**$4,506,515**		$2,061,704	$689,681	$849,805	$351,810	$407,382	$119,174	$11,191	$15,769	**$4,506,515**

	Decision/ALLOCATOR	RESIDENTIAL	GS < 50 kW	GS - 50 to 1000 kW - Non Interval	GS - 50 to 1000 kW - Interval	GS > 1000 to 5000 kW	LARGE USER	SMALL SCATTER LOAD	STREETLIGHT	TOTAL
		kWh	**kWh**	**kVA**	**kVA**	**kVA**	**kVA**	**kWh**	**kVA**	
INCREMENTAL RATE RIDERS	**kWh or kVA**	**$ 0.00040**	**$ 0.00030**	**$ 0.05**	**$ 0.04**	**$ 0.03**	**$ 0.02**	**$ 0.00020**	**$ 0.05**	

APPENDIX 10-B: 1995 - 1999 AVERAGE LOSS RATE

YEARS	KWH PURCHASED (1)	KWH PURCHASED LARGE USERS (2)	KWH PURCHASED OTHERS (3)	KWH SOLD SYSTEM (4)	KWH SOLD LARGE USERS (5)	KWH SOLD OTHERS (6)	SYSTEM LOSS TOTAL (7)=(1-4)/4	SYSTEM LOSS LARGE USERS (8)=(2-5)/5	SYSTEM LOSS OTHERS (9)=(3-5)/5
95-99 Total	127,795,853,948	12,344,308,807	115,451,545,141	123,941,341,929	12,172,674,102	111,768,667,827	3.11%	1.41%	3.30%
1999	26,105,792,326	2,567,004,826	23,538,787,500	25,332,878,858	2,531,313,309	22,801,565,549	3.05%	1.41%	3.23%
1998	25,430,368,599	2,570,238,663	22,860,129,936	24,696,943,404	2,534,502,182	22,162,441,223	2.97%	1.41%	3.15%
1997	25,337,622,821	2,292,505,109	23,045,117,712	24,551,693,521	2,260,630,223	22,291,063,298	3.20%	1.41%	3.38%
1996	25,395,069,403	2,375,605,511	23,019,463,892	24,640,887,343	2,342,575,200	22,298,312,142	3.06%	1.41%	3.23%
1995	25,527,000,799	2,538,954,698	22,988,046,101	24,718,938,803	2,503,653,188	22,215,285,616	3.27%	1.41%	3.48%

Toronto Hydro
Electrical Losses of Large Customers

December 1999

Electrical Losses of Large Customers

In July 1999, a study was carried out to estimate the electrical losses of the Large Customers in Toronto Hydro. Large Customers have an average monthly demand of 5MW or above. In December 1999, the actual 1998 load factor data for customers by type were available. The load factor assumption used in July 1999 was 0.60 whereas the actual load factor was 0.7012. The new data was used to update the July study and results presented in this report. This report is divided into three parts. Part 1 covers the theoretical background for the calculation of electrical losses. Part 2 details the assumptions and estimation of electrical losses of the Large Customers in Toronto Hydro, using the theories developed in Part 1. Part 3 is the conclusion of results. Supporting documents are given in the appendices.

Part 1. Theoretical Background

Theoretically energy losses of any network equipment can be measured by installing energy meters at points where energy is flowing in and out of the equipment. This is however costly in both capital expenditure on meter installation and operating costs in maintaining the database. Instead, analysis of the network at peak power will typically be made and the load variation over time is accounted for through the use of load factors and loss factors.

1.1 Derivation of Peak Loss Percentage

For a balanced three-phase system, the line loss is given by:

$$P_{loss} == 3\frac{I^2 R}{1000} kW$$

where:

I = load current in feeder in amperes, and
R = resistance of feeder in ohms.

The load current in feeder in amperes is estimated from average monthly demand, using the latest load factor for the type of customer, and the power factor. The resistance of feeders in ohms is derived from the specific resistance for the type of feeders and the measured lengths of the feeders, taking into account whether the sections in a feeder are run in series or parallel.

Peak Loss Percentage is derived from the following relationship.

$$Peak\ Loss\,\% = \frac{Peak\ Loss\ kW}{Peak\ Load\ kW\ at\ customer + Peak\ Loss\ kW} \times 100$$

1.2 Loss Factor

The Loss Factor is defined as:

$$LossFactor = \frac{Average\ Power\ Loss}{Peak\ Power\ Loss}$$

The exact value of the Loss Factor depends on the shape of the load curve over a period of time. As discussed in "Distribution System Performance Improvement Guide" (March 1997) written by David Brown and published by American Public Power Association, the loss factor is related to the load factor, and can be approximated as follows:

$$Loss\ Factor = 0.20 \times Load\ Factor + 0.80 \times (Load\ Factor)^2$$

1.3 Energy Loss Percentage

The Energy Loss Percentage is calculated as follows:

$$Energy\ Loss\,\% = \left(\frac{Energy\ Loss\ kWh}{Energy\ Loss\ kWh + Energy\ Consumed\ kWh} \right) \times 100$$

where,

$$Energy\ Loss\ kWh = Loss\ Factor \times Peak\ Loss\ kW \times 8{,}760\ hours$$

Part 2. Estimation for Toronto Hydro

In 1998, there were 41 customers on the list of Large Customers in the Toronto Hydro system and they are distributed by office as follows.

Toronto Hydro Total	**41**
Toronto Office	24
Scarborough Office	7
North York Office	5
Etobicoke Office	4
York Office	1
East York Office	0

Data for 24 customers were collected and analyzed. The Large Customers were assumed to be the only customer on the feeder line in order to simplify the calculations. The 24 customers in the sample were all supplied from HV, and only line losses are involved and not transformer losses. For the Large Customers in Scarborough, load flow study results were available for Summer Peak 1998. From this analysis of the sample of 24 customers:

Load factor = 0.7012 (1998 data)
Assumed power factor = 0.85
Peak Loss Percentage = 0.54%

Once the Peak Loss Percentage for the sample is obtained, the Energy Loss Percentage for the whole class of Large Customers on HV Supply is calculated as follows:

Peak Loss kW
= Peak Load kW × Peak Loss Percentage
= 398,769 kW (1998 data) / [1 – 0.54%] × 0.54%
= 2,165 kW

Energy Loss kWh
= Peak Loss kW × Loss Factor × 8,760 hours
= 2,165 kW × [0.2 × 0.7012 + 0.8 × 0.7012^2] × 8,760 hours
= 2,165 kW × 0.5336 × 8,760 hours
= 10,120,255 kWh

Energy Loss Percentage
= Energy Loss kWh / (Energy Consumed kWh + Energy Loss kWh) × 100
= 10,120,255 kWh / (2,449,498,284 kWh (1998 data) + 10,120,255 kWh) × 100
= 0.41%

Part 3. Conclusion of Results

The Energy Loss Percentage was estimated to be 0.41%. The result is based on a sample of 24 customers supplied at high voltage, out of the 41 large customers. The sample represented about 59% of the number of all Large Customers and about 61% of its kW demand. In the July 1999 study, a load factor assumption of 0.60 was used and the Energy Loss Percentage was 0.46%. The actual class load factor for 1998 was a higher 0.7012. This higher load factor means a lower Peak kW Demand, as the Peak kW Demand is calculated from the average kW demand data. Consequently the updated Energy Loss Percentage is a lower 0.41%.

The customers in the sample are typically supplied at high voltage (27.6kV or 13.8kV) and the losses are generated from the supply line circuits and no transformer losses are incurred. In general, the energy loss percentages are higher for longer supply line length, and heavier load on the supply line. And the percentages are lower with more lines supplying the customer, larger sizes of supply lines and higher supply voltages.

Toronto Hydro-Electric System Limited (THESL)
Standby Facilities Charge for Parallel Generation Policy
REVISED AUGUST 2002

Overview

The Standby Facilities Charge is applicable to a customer with:

- load displacement nameplate generation capacity equal to or greater than 500 kVA
- a requirement for backup distribution capacity if the load displacement (parallel) generation is not operating

The purpose of the Standby Facilities Charge is to recover the cost of providing reserved capacity to these customers. THESL normally installs distribution capacity to carry the estimated load and recovers the costs through the rates when the customer uses electricity. If the customer requests additional distribution capacity on a standby basis, the costs of capital, operations and maintenance, taxes and administration to provide that capacity would not be recovered in the standard rates, since the standard rates are based on the assumption of continuous use. Therefore, there has to be a separate standby charge so that the cost burden does not fall on general ratepayers.

The Standby Facilities Charge normally applies to the amount of backup distribution capacity a customer contracts for (Contract Backup Demand), and the variable rate (per kVA) is the same as is applicable to the customer's demand under the standard distribution rates. However, to the extent that the backup capacity is actually drawn upon by the customer, as reflected in the customer's peak metered demand for the billing period, the Standby Facilities Charge is correspondingly reduced.

The Contract Backup Demand can be determined by using either the full nameplate value of the generating plant or a portion of that value agreed by the customer and THESL. The customer and THESL will negotiate the amount required by the customer as backup capacity. Consideration will be given to load shedding and load displacement when negotiating the backup amount. If a customer determines that no backup capacity is required, that capacity is available for use by other customers. In that case, the customer does not pay Standby Facilities Charges nor will the customer be entitled to rely upon the additional capacity if its generator fails. However, any customer operating parallel generation with a nameplate capacity of 500 kVA and up will be required to sign a Standby Facilities contract, which can stipulate a Contract Backup Demand of zero kVA, for the purpose of enforcing Backup Overrun penalties.

In the event that a customer contracts for a zero level of Contract Backup Demand, but in fact imposes a backup demand on the system, the customer will be deemed to have made an election to contract for the standby facilities actually used, and will be assessed the Standby Facilities charge as well as Backup Overrun penalties.

Rate Structure

In addition to the standard distribution, energy, and other rates applicable to the customer's metered demand, the Standby Facilities Rate is composed of an Administration Charge and the Standby Facilities Charge, applicable to the Billed Backup Demand, as described below:

1. *Contract Backup Demand* is the reserved kVA capacity as agreed between the customer and THESL.

2. *Standby Facilities Charge* – this rate is applicable for each kVA/month of Billed Backup Demand. The Billed Backup Demand will be equal to or less than the Contract Backup Demand, depending on whether the reserved capacity is actually drawn upon. (See Determination of Billed Backup Demand.) For customers who own their transformers, the Standby Facilities Charge will be net of the transformer allowance credit.

3. *Administration Charge* – A monthly administration charge will be applied to cover the incremental cost of monitoring, billing and administration related to providing Standby Facilities service.

Backup Overrun Adjustment

Contract Backup Demand is reviewed on a quarterly basis. In the event that in any of the three preceding billing periods, the customer has used an amount of backup capacity in excess of the Contract Backup Demand, the Contract Backup Demand will be increased to the highest monthly level of utilisation which has occurred in the three preceding months.

In addition, the difference between the existing Contract Backup Demand and the adjusted Contract Backup Demand will be back-billed for the preceding eleven months from the month of review at the current or then applicable Standby Facilities Charge rate, along with applicable interest charges. The adjusted Contract Backup Demand will remain in effect for a period of not less than twelve months from the date of revision, absent any demonstrable change in the operation of the generator (i.e., derating or decommissioning).

Determination of Standby Facilities Usage Levels

For the purpose of determining the utilized quantity of Standby Facilities capacity, as well as Backup Overrun, if any, the differences between
i) the demand at the last recorded interval of operation before the outage and the first recorded interval during the outage; as well as
ii) the demand at the last recorded interval of operation during the outage and the first recorded interval after the outage;
will be assessed. TH Electric System will base the determination on the average of these two values.

The instantaneous demand difference with the generator on and off is determinative of the standby capacity used and consequently any overrun used, providing that another larger peak is not established at another time during the billing period. Effectively, it is the immediate change in demand rather than the difference in levels of demand with the generator on and off over the entire period that is critical.

In addition, Backup Overrun charges will only be applicable to the extent that the peak demand inclusive of Overrun demand exceeds any other metered demand level in the billing month. This precludes Backup Overrun charges from being assessed in any case where the normal peak demand is established at another time during the billing month.

Backup Overrun cannot in any case exceed the capacity of the generation being operated. Operating conditions, fuel types, and other factors may lower the achievable output of a generator relative to its nameplate capacity; in that case, TH Electric System will accept two actual capacity levels for applicability, based on predictable conditions (e.g., time of year, fuel type) and valid documentation, for contract purposes.

Determination of Billed Backup Demand

Contract Backup Demand establishes a ceiling for Billed Backup Demand (excluding Backup Overrun provisions). In the case where a customer's parallel generator operates continuously over the billing period, the customer is billed the standard rates on its metered consumption, and the metered consumption is deemed not to reflect any use of backup capacity, although the capacity is nevertheless reserved. In this instance, Billed Backup Demand is equal to the Contract Backup Demand. (See Example 1 following.)

In the case where a customer's parallel generator has not operated at all over the billing period, the customer is deemed to have actually used the reserved capacity, and this use will be reflected in the metered quantities. In this instance, THESL costs are recovered through the standard rates and the Billed Backup Demand is zero. (See Example 2 following.)

In the case where a customer's parallel generator has operated for some, but not all of the billing period, the customer is billed on the greater of: i) maximum metered demand with the generator off; and ii) maximum metered demand plus Contract Backup Demand with the generator on. (See Example 3 following.) Billed Backup Demand will be reduced from the Contract Backup Demand level by the amount of Standby Facilities Capacity used. If the amount of Standby Facilities Capacity used when the generator is off is larger than the Contract Backup Demand, Backup Overrun penalties will apply. (See Example 4 following.)

In certain operating circumstances, metered demand in the billing period may in fact be lower when the parallel generator is off, in which case standard rates apply to the metered peak demand and the Billed Backup Demand will equal the Contract Backup Demand. If a customer could determine that metered demand would normally be lower when the parallel generator was not operating, that customer would presumably contract for a zero level of Contract Backup Demand.

Parallel Generation Data Requirements

Customers will be contractually required to provide THESL with certain operating and load information pertaining to parallel generators with nameplate capacities equal to or greater than 500 kVA. Only the information needed for billing and operations purposes will be required, and this information will be kept confidential and used only for those purposes.

All new generators will be metered. The generator's load profile will be compared to the metered (i.e., supplied by THESL) load profile to determine the application of the Standby Facilities Charge and any associated charges.

As most existing generators are not metered separately, Billed Backup Demand and firm demand will be determined using the customer's RIMS load data and the generator's operation log.

For safety reasons, generator-utility interface protective devices (circuit breakers) are required for customer owned generators. These circuit breakers are tripped (protection on) when the customer owned generators are operational and are closed when the same generators are off (protection off), to avoid feedback of electricity into the utility's distribution system. THESL maintains a monthly log on each breaker[1]. If the log indicates a generator outage, this will be taken into account in determining the peak demand during the outage period and the Billed Backup Demand.

The billing of Standby Facilities charges is illustrated in the following examples.

---

[1] Example of Breaker LOG
10/01/01 00:00:00

04:39:01 ABC Customer 52G BREAKER POSITION CLOSED

10/05/01 00:00:00

23:33:28 ABC Customer 52G BREAKER POSITION TRIPPED

Example 1

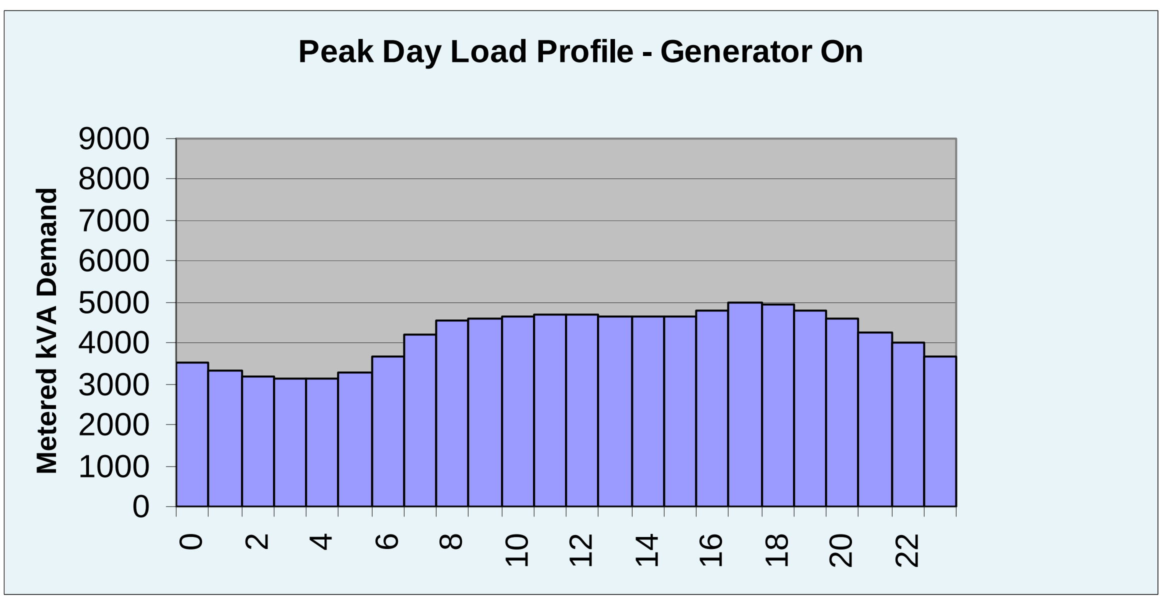
Parallel Generation Operational for the Entire Billing Month (Breaker Tripped and Never Closed)

If in any particular month, the generator is fully operational with no downtime, the customer will pay the Standby Facilities Charge in addition to the regular monthly distribution charges.

Contract Backup Demand	2000 kVA
Peak Metered Demand	5000 kVA
Breaker was TRIPPED with no CLOSED	
Standby Facilities Charge	APPLICABLE

Monthly Charges:

Distribution Charge	= 5000 kVA * applicable class distribution rates
Standby Facilities Charge	= 2000 kVA * applicable Standby Facilities rates
Administration Charge	per current approved rates

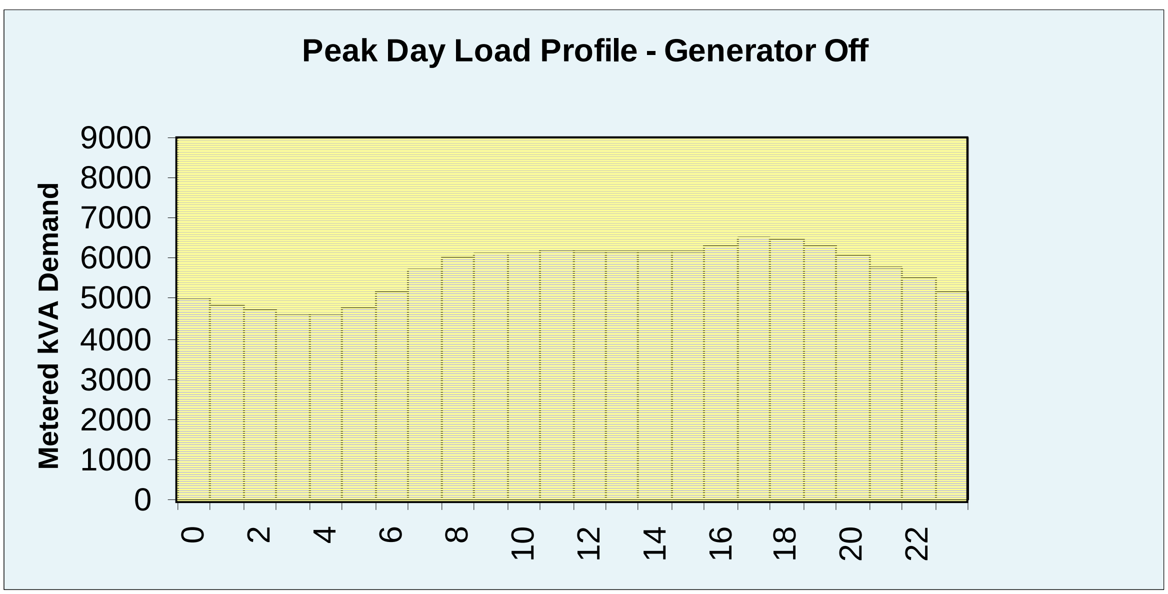


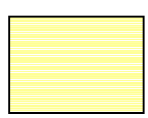
Example 2

Parallel Generator Out of Operation for the Entire Billing Month (Breaker was Closed and Never Tripped)

If the Parallel Generator is not operational during the entire billing month, the customer is assumed to have used the Standby Facilities and to have paid for the reserved capacity through the regular distribution charges.

Contract Backup Demand	2000 kVA
Peak Metered Demand	6500 kVA
Breaker was CLOSED with no TRIPPED	
Standby Facilities Charge	NOT APPLICABLE



Overlay indicates generator out of operation 

Example 3

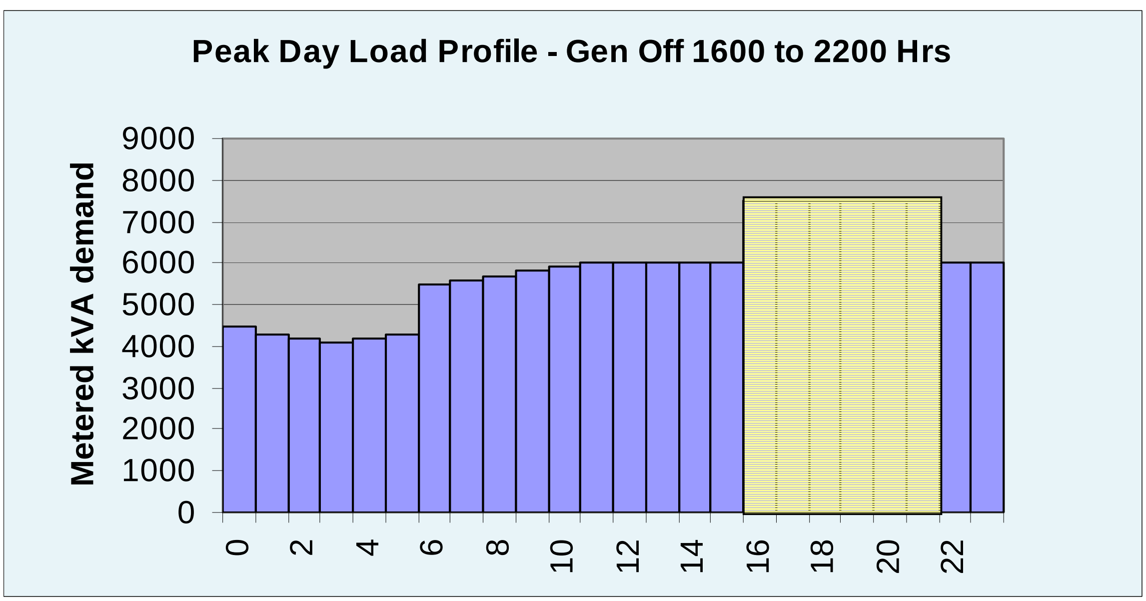
Parallel Generator Operational for Part of the Billing Month (Breaker in both Tripped and Closed Positions)

In months during which the generator is operational part of the time, the customer will be billed for Standby Facilities Charge based on the instantaneous difference between the metered kVA with generation running and the metered kVA without generation running, presuming peak demand is not established at another time during the billing month.

Contract Backup Demand	2000 kVA
Peak Metered Demand **with generation on**	6000 kVA
Breakers TRIPPED and CLOSED	
Peak Metered Demand **with generation off**	7500 kVA

Monthly Charges:

Distribution Charge	= 7500 kVA * applicable class distribution rates
Standby Facilities Charge	= 2000 – (7500-6000)
	= 500 kVA * applicable Standby Facilities rates
Administration Charge	per current approved rates



Example 4

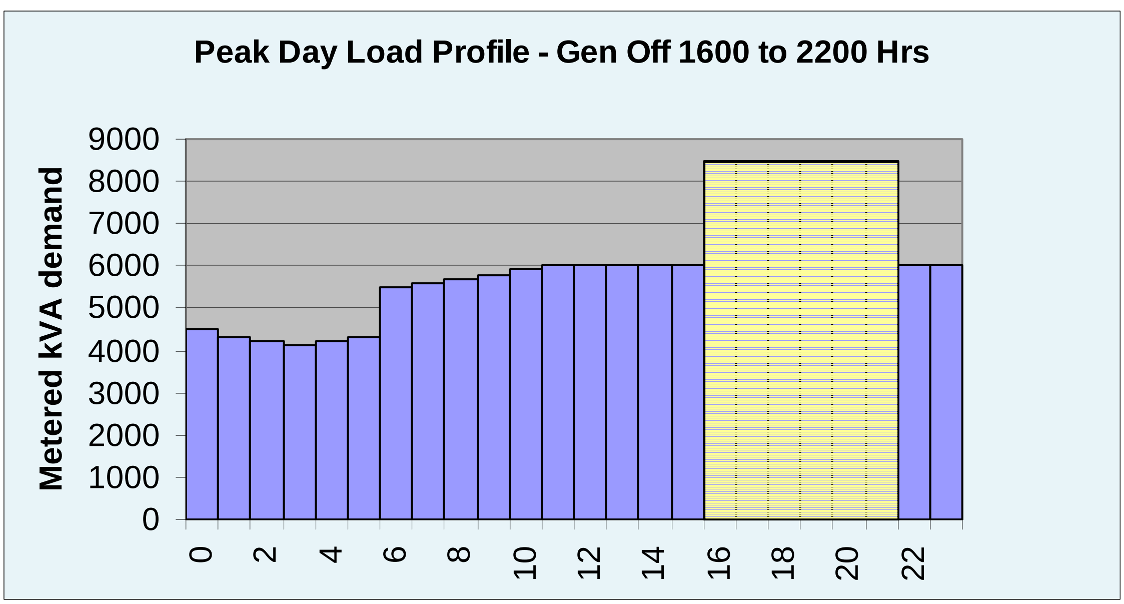
Parallel Generator Operational for Part of the Billing Month (Breaker in both Tripped and Closed Positions) – with Backup Overrun

Standby Facilities Charge based on the instantaneous difference between the metered kVA with generation running and the metered kVA without generation running, presuming peak demand is not established at another time during the billing month.

Contract Backup Demand	2000 kVA
Peak Metered Demand **with generation on** Breakers TRIPPED and CLOSED	6000 kVA
Peak Metered Demand **with generation off**	8500 kVA

Monthly Charges:

Distribution Charge	= 8500 kVA * applicable class distribution rates
Standby Facilities Charge	= 2000 – (8500 – 6000) = 2000 – 2000 (maximum) = 0 kVA
Administration Charge	per current approved rates
Backup Overrun	= (8500- 6000) - 2000 = 500 kVA subject to applicable backup overrun re-billing



APPENDIX 10-E DERIVATION OF STANDBY ADMINISTRATION CHARGES

		Time Requirement per Month	Hourly Labour Rates (with	Total Cost
Billing System	- CSR stops a computer generated bill - Manually enters the different reading into the Billing System - Applies Adjustments - Reproduces Bill	0.3	$ 47.00	$ 14.10
Metering Dept.	- Provides a hourly detail metering report to determine Firm Power and Backup Power	0.5	$ 52.00	$ 26.00
Operations	- Tracks and reports on the Closing and Opening of the Protection Circuit to determine when Co-gen was operational or not	1	$ 71.00	$ 71.00
Rates	- Collects the following information: - operational log to determine generator's on and off time periods - hourly metering data to verify the operational log and to determine the amount of backup if generator was down - manually recalculate the bills - apply adjustment into the billing system - initiate a rebill to the Billing System	1	$ 71.00	$ 71.00
	- the quarterly review of the Contract Demand Amount (Six hours divided by 12 months)	0.5	$ 71.00	$ 35.50
The following initial setup Costs are not included in the monthly administration chare	- setup for the manual bill calculation - the negotiations of contract			
				$ 217.60
	ROUNDED			**$ 200.00**

CHAPTER 11 – SPECIFIC SERVICE CHARGES

11.0 Introduction

1. The DRH provides a comprehensive set of specific services that distributors could provide to customers, associated standard charges and a specific basis for the determination of service charges.

2. Attached, as part of this Application is a completed Schedule 11-1: Specific Service Charges – Standard Amounts that outlines the specific service charges THESL hereby submits for approval.

3. THESL uses the standard amount for the applied-for specific service charges as indicated in Schedule 11-1. No formulaic specific service charges are being sought. Accordingly, Schedule 11-2 is not applicable and is not included as part of this Application.

11.1 Revenue from Specific Service Charges

4. Attached, as part of this Application is a completed Schedule 11-3: Specific Service Charges: Revenue that calculates 2006 revenues from Specific Service Charges based on the projected 2006 volume. The total projected 2006 revenue of $11.5 million, comprising the applied-for Specific Service Charges of $5.4 million, Pole Attachment revenues of $1.4 million and Late Payment Charges of $4.6 million, is factored into the 2006 EDR Model as a revenue offset.

SCHEDULE 11-1: SPECIFIC SERVICE CHARGES - STANDARD AMOUNTS

Specific Service Charges - Summary

Rate Code	Standard Name	Std. Amt		Calculation Method - Check Box		Time & Materials
				Standard Formula (attach calculation &	Other Formula (attach calculation &	
1	Arrears Certificate	$15	____	____		____
2	Statement of account	$15	____	____	____	____
3	Pulling post dated cheques	$15	____	____	____	____
4	Duplicate invoices for previous billing	$15	X	____	____	____
5	Request for other billing information	$15	____	____	____	____
6	Easement letter	$15	X	____	____	____
7	Income tax letter	$15	X	____	____	____
8	Notification charge	$15	____	____	____	____
9	Account history	$15	____	____	____	____
10	Credit reference/credit check (plus credit agency costs)	$15	____	____	____	____
11	Returned cheque charge (plus bank charges)	$15	X	____	____	____
12	Charge to certify cheque	$15	____	____	____	____
13	Legal letter charge	$15	____	____	____	____
14	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$30	X	____	____	____
15	Special meter reads	$30	X	____	____	____
16	Collection of account charge - no disconnection	$30	X	____	____	____
17	Collection of account charge - no disconnection after regular hours	$165	____	____	____	____
18	Disconnect/Reconnect at meter - during regular hours	$65	X	____	____	____
19	Install/Remove load control device - during regular hours	$65	X	____	____	____
20	Disconnect/Reconnect at meter - after regular hours	$185	X	____	____	____
21	Install/Remove load control device - after regular hours	$185	X	____	____	____
22	Disconnect/Reconnect at pole - during regular hours	$185	X	____	____	____
23	Disconnect/Reconnect at pole - after regular hours	$415	X	____	____	____
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30	X	____	____	____
25	Service call - customer-owned equipment	$30	____	____	____	____
26	Service call - after regular hours	$165	____	____	____	____
27	Temporary service install & remove - overhead no transformer	$500	____	____	____	____
28	Temporary service install & remove - underground no transformer	$300	____	____	____	____
29	Temporary service install & remove - overhead with transformer	$1,000	____	____	____	____
30	Specific Charge for Access to the Power Poles $/pole/year	$22.35	____	____	____	____
Additional Charges - Please be Specific						
31	Pole Attachment (Third Party)	$18.55	____	____	Reciprocal Agreement	____
32	Pole Attachment (Third Party)	-$22.75	____	____	Reciprocal Agreement	____
33	Standby Administration Charges	N/A	____	____	X	____

Regular Hours of Operation : Weekdays (excluding statuatory holidays) from 8:00 am to 4:00 pm
(revise as appropriate)

NOTE: Application of higher charges for services done outside of regular hours will be limited to instances where the customer requests "after hours" service. Emergencies related to safety or reliability will not be billed at the after regular hours rates.

SCHEDULE 11-3: SPECIFIC SERVICE CHARGES - REVENUE

Rate Code	Description	Amount	2002 Volume	2003 Volume	2004 Volume	3-Year Average	2006 Forecast	Revenue
1	Arrears certificate	$15						
2	Statement of account	$15						
3	Pulling post dated cheques	$15						
4	Duplicate invoices for previous billing	$15	1,000	1,000	1,000	1,000	1,000	$ 15,000
5	Request for other billing information	$15						
6	Easement letter	$15	1,344	1,214	1,198	1,252	1,200	$ 18,000
7	Income tax letter	$15	1,000	1,000	1,000	1,000	1,000	$ 15,000
8	Notification charge	$15						
9	Account history	$15						
10	Credit reference/credit check (plus credit agency costs)	$15						
11	Returned cheque charge (plus bank charges)	$15	7,937	8,122	7,739	7,933	8,000	$ 120,000
12	Charge to certify cheque	$15						
13	Legal letter charge	$15						
14	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$30	90,224	96,016	97,682	94,641	95,000	$ 2,850,000
15	Special meter reads	$30	1,000	1,000	1,000	1,000	1,000	$ 30,000
16	Collection of account charge - no disconnection	$30	67,355	44,336	57,552	56,414	60,000	$ 1,800,000
17	Collection of account charge - no disconnection - after hours	$165						
18	Disconnect/Reconnect at meter - during regular hours	$65	6,157	6,565	8,043	6,922	3,500	$ 227,500
19	Install/Remove load control device - during regular hours	$65	2,500	2,500	2,500	2,500	2,500	$ 162,500
20	Disconnect/Reconnect at meter - after regular hours	$185	250	250	250	250	250	$ 46,250

Rate Code	Description	Amount	2002 Volume	2003 Volume	2004 Volume	3-Year Average	2006 Forecast	Revenue
21	Install/Remove load control device - after regular hours	$185	100	100	100	100	100	$ 18,500
22	Disconnect/Reconnect at pole - during regular hours	$185	500	500	500	500	500	$ 92,500
23	Disconnect/Reconnect at pole - after regular hours	$415	50	50	50	50	50	$ 20,750
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30	12	12	12	12	12	$ 360
25	Service call - customer-owned equipment	$30						
26	Service call - after regular hours	$165						
27	Temporary service install & remove - overhead - no transformer	$500						
28	Temporary service install & remove - underground - no transformer	$300						
29	Temporary service install & remove - overhead - with transformer	$1,000						
30	Specific charge for Access to the Power Poles $/pole/year	$22.35	40,915	54,202	55,380	50,166	57,186	$ 1,278,107
31	Specific charge for Access to the Power Poles $/pole/year*	$18.55	17,168	18,413	17,349	17,643	17,782	$ 329,856
32	Specific charge for Access to the Power Poles $/pole/year*	-$22.75	7,337	7,365	7,318	7,340	7,397	$ (168,282)
33	Standby/Backup Monthly Administrative Charges	$200.00	60	60	60	60	60	$ 12,000
	Revenue from Specific Service Charges							$ 5,428,360
	Revenue from Pole Attachment							$ 1,439,681
	Revenue from Late Payment Charges		$ 4,073,815	$ 5,354,355	$ 4,606,068	$ 4,678,079	$ 4,606,068	$ 4,606,068
	Total Revenue from Specific Charges (including Pole attachment) and Late Payment Charges							$ 11,474,109

CHAPTER 12 – OTHER REGULATED CHARGES

12.0 Introduction

1. Other regulated charges are exclusive of the distribution monthly service charges, volumetric rates, and specific service charges. They include: RPP Administration Charge, Retail Service Charges, Distributor-consolidated Billing Charge, Retailer-consolidated Billing Credit, Service Transaction Requests and Processing Charges, and Non-competitive Energy Charges. For rates effective May 1, 2006, THESL proposes to maintain the level of these charges, with the exception of the transmission connection rates. Current rates are listed in Schedule 2-4.

12.1 RPP (formerly SSS) Administration Charge

2. THESL applies a standard charge of $0.25 per month, per customer.

12.2 Monitoring and Cost Tracking

3. THESL tracks the difference between the retail service charges rendered to customers and retailers, and the direct incremental costs for the provision of these services. In its regulatory asset recovery filing, THESL submitted to the OEB that, since these costs did not exceed the materiality threshold, THESL has not recorded these amounts in a retail services costs variance account ("RCVA"). In its decision, OEB ruled the materiality threshold does not apply to the retail service charges and directed distributing companies to record the variances in the RCVA. THESL now complies with the DRH requirements.

12.3 Non-Competitive Electricity Charges

4. THESL maintains the standard charges for non-competitive service in accordance with the DRH. Consistent with the Board's letter dated July 5, 2005, THESL is requesting a change to the Transmission Connection rates. THESL notes that the Board also indicated it will issue guidance later this summer, regarding disposition of outstanding retail settlement variance accounts balances.

12.3.1 Retail Transmission Service Rates

5. The Board issued guidelines to revise the Retail Transmission Service rates, and the proposed methodology is outlined below.
6. THESL reviews the monthly balances in the Transmission Network and Connection RSVA accounts. Since the RSVA-network shows a pattern of oscillation between negative and positive values, THESL is not proposing a rate adjustment to network services. However, the RSVA-connection shows a consistent pattern of over-recovery and THESL proposes to adjust the Transmission Connection rate.
7. In accordance with Board's instruction, THESL has analysed the monthly differences between 2006 costs and revenues and determines that Retail Transmission Connection rates are over-recovering by approximately 5 percent, as shown in Appendix 12-A. As a result, THESL proposes to reduce the Retail Transmission Connection rates to its customers by 5 percent to keep the revenues more closely in line with costs.

APPENDIX 12-A: 2006 TRANSMISSION CONNECTION REVENUE AND COSTS

	Transmission Connection Revenue at Retail Rates	Transmission Connection Cost	Difference
January	9,969,946	9,021,358	948,588
February	8,491,339	8,883,959	(392,620)
March	9,424,686	8,433,275	991,411
April	8,817,915	8,090,081	727,834
May	8,984,273	8,081,412	902,861
June	9,431,064	9,954,142	(523,078)
July	10,100,030	9,887,108	212,922
August	10,290,926	9,895,968	394,958
September	8,940,708	9,014,106	(73,398)
October	9,120,674	8,081,326	1,039,348
November	8,681,274	8,404,491	276,783
December	9,824,582	8,791,664	1,032,918
Total	112,077,419	106,538,890	5,538,528
% Difference			**5%**

CHAPTER 13 -MITIGATION

13.0 Impact Analysis

1. Following the impact analysis methodology provided by the 2006 EDR Model, THESL has conducted the following bill impacts for each class or group of customers:
   - A comparison of a customer's total bill, based on proposed and existing rates (including Board-approved rate riders), assuming a constant commodity price and other rates;
   - A comparison of a customer's "delivery charges", based on proposed and existing rates (including Board-approved rate riders), excluding the commodity component; and
   - A comparison of a customer's "distribution charges", based on proposed and existing rates (including Board-approved rate riders), excluding the commodity component and other rates.

13.1 Mitigation Methodologies

2. None of the classes or groups of customers experience total bill increases of greater than 10 percent. Therefore, a rate impact mitigation plan is not required nor included as part of this Application.

CHAPTER 14 – COMPARATORS AND COHORTS

14.1 Filing Requirements

1. The Applicant acknowledges the OEB's comment at Section 14.1 of the Handbook that "The comparators and cohorts will be determined on the basis of data filed by distributors as part of the RRR, so that no additional filings will be required."

14.2 Utilization of Comparators and Cohorts Analysis and Data

2. THESL acknowledges the Board's determination that it will make use of Comparators and Cohorts ("C&C") in the 2006 EDR process, and that it will publish the C&C analysis. However, it is clear that the Board also recognized in its May 11, 2005 Report on the 2006 EDR Handbook that there are limitations to be placed on the use of the C&C data. THESL believes that the implications of the misuse of C&C data for the reputations of distributors and their relationships with their customers, financial institutions and credit rating agencies make it critical that all parties to the 2006 EDR applications have a clear understanding as to the manner in which the C&C data may be used, and the manner in which it is not to be used.

3. At page 97 of the Report, the Board accepted the evidence of Mr. Camfield and Dr. Lowry that the analysis should be used only as a screening mechanism that would identify which distributors should receive closer scrutiny. According to Mr. Camfield, the analysis itself is not an indicator of the level of efficiency of a distributor, and

consequently, the Board acknowledged the following limitations on the analysis:

> "The Board takes this to mean that the analysis cannot be used for any form of benchmarking for rate setting purposes and that the analysis is not evidence as to the prudence of a particular expense level. Specifically, the Board understands that although analysis may identify an average level of spending, it would be incorrect to draw the conclusion that any particular level represented an 'efficient' level of spending. Further, the analysis itself is not evidence one way or the other as to the prudence of a particular level of expenditure."

4. THESL understands this to mean that should a distributor be considered an outlier in respect of certain comparators, it may be called on to justify its own costs, but that the Board will make no findings with respect to distributor efficiency as a result of the C&C process; the distributor will not be under any obligation to analyze the costs of other distributors in order to try to determine why it is not more like them; and a distributor will not be subject to arbitrary reductions in respect of its revenue requirement in order to bring certain of its costs more in line with a notional "prudent" or "efficient" level of spending. As the Board observed,

> "While the Board cannot limit in advance of a particular proceeding what evidence will be presented, the Board expects that the analysis itself would be of little probative value in determining the appropriate level of a particular expense. A distributors [*sic.*] with expense levels that are "outliers" will have the opportunity to justify the expense(s). The Board recognizes that the analysis is

> experimental and that the data and/or the methodology may be unreliable."

5. The Board continued by cautioning distributors that may consider introducing alternative analysis that supports a different comparative conclusion, that "it has already indicated that comparative analysis is not determinative of prudence. Challenging the analysis will not be sufficient to fulfill the distributor's obligation to demonstrate that the level of expense is appropriate." THESL suggests that a similar caution is appropriate for intervenors that may seek to introduce alternative analyses that support different comparative conclusions.

6. At page 98 of the Report, in its discussion of the publication of the analysis, the Board wrote:

> "The Board will ensure that the analysis contains the appropriate caveats in light of its experimental nature. The Board will emphasize that initial application of the C&C analysis in the 2006 rate setting process is exploratory in nature and that the analysis is not intended to be a comprehensive or definitive analysis of distributor efficiency. The fact that a distributor has high costs relative to others in its cohort does not necessarily indicate inefficiency on the part of that distributor."

7. THESL urges the Board to word these caveats as strongly as possible, so that the limitations of the C&C process, and of the use to be made of the analysis, are clear to both parties to the rate proceedings and others who may not have been involved in either the 2006 EDR process that led to the Handbook, or individual distribution rate applications. THESL also requests that when issuing its caveats, it emphasize not only that the

analysis is not intended to be a comprehensive or definitive analysis of distributor efficiency, and that the fact that a distributor has high costs relative to others in its cohort does not necessarily indicate inefficiency on the part of that distributor, but also that the analysis, or the fact of high costs, is not necessarily an indicator of distributor prudence or imprudence.

CHAPTER 15 – SERVICE QUALITY REGULATION

15.0 Introduction

1. No revisions to the Service Quality Indicators have been made for the 2006 electric distribution rate process.

2. THESL monitors service quality and reliability monthly and reports the information annually to the Board as well as maintains a record of the causes of outages in accordance with DRH Table 15.2.

3. Attached is Schedule 15-1: Service Quality and Reliability Performance 2002 to 2004 that provides a summary of annual performance for years 2002 to 2004 inclusive for the reported service quality and reliability indicators.

SCHEDULE 15-1: SERVICE QUALITY AND RELIABILITY PERFORMANCE 2002 TO 2004

1. a. Connection of New Services – Low Voltage

Standard: 90% or better

2002	2003	2004
96.7%	**98.7%**	**98.4%**

1. b. Connection of New Services – High Voltage

Standard: 90% or better

2002	2003	2004
100.0%	**98.6%**	**100.0%**

2. Underground Cable Locates

Standard: 90% or better

2002	2003	2004
94.2%	**90.9%**	**93.5%**

3. Appointments Met

Standard: 90% or better

2002	2003	2004
96.6%	**95.2%**	**98.7%**

4. Telephone Accessibility (Telephone Service Factor)

Standard: 65% or better

2002	2003	2004
65.5%	**67.3%**	**85.3%**

5. Written Responses to Enquiries

Standard: 80% or better

2002	2003	2004
87.5%	**93.3%**	**97.1%**

6. a. Emergency Response - Urban

Standard: 80% or better

2002	2003	2004
74.9%	**86.4%**	**89.3%**

7. SAIDI (System Average Interruption Duration Index) - Minutes

Standard: Within the range of performance over the previous 3 years

2002	2003	2004
80.95	**87.98**	**66.01**

8. SAIFI (System Average Interruption Frequency Index)

Standard: Within the range of performance over the previous 3 years

2002	2003	2004
1.59	**1.98**	**1.59**

9. CAIDI (Customer Average Interruption Duration Index)

Standard: Within the range of performance over the previous 3 years

2002	2003	2004
50.92	**44.47**	**41.47**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (RP-2005-0020/EB-2005-0421)

August 2 2005

1-1 GENERAL (Input)

Enter general information related to the Application

Version:		2
Name of Applicant		Toronto Hydro-Electric System Limited
License Number		ED-2002-0497
File Number(s)		RP-2005-0020/EB-2005-0421
Contact:		
	Name	Anthony Lam
	e-mail	ALAM@torontohydro.com
	telephone	416-542-2876
Date of Application:		August 2 2005

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (RP-2005-0020/EB-2005-0421)

August 2 2005

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2002 Total $	2002 Unclassified $	2002 Non-Distribution $	2002 Distribution $
GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)					
	Land and Buildings	50,017,133	-0	-0	50,017,133
	TS Primary Above 50	-0	-0	-0	0
	DS	129,675,917	-0	-0	129,675,917
	Poles, Wires	1,796,056,691	-0	-0	1,796,056,691
	Line Transformers	410,814,278	-0	-0	410,814,278
	Services and Meters	120,662,277	-0	-0	120,662,277
	General Plant	107,942,004	-0	-0	107,942,004
	Equipment	111,615,553	-0	-0	111,615,553
	IT Assets	113,097,835	-0	-0	113,097,835
	CDM Expenditures and Recoveries	-0	-0	-0	0
	Other Distribution Assets	47,739,421	-0	-0	47,739,421
	Contributions and Grants	-84,511,703	-0	-0	-84,511,703
	Accumulated Amortization	-1,264,225,545	-0	-0	-1,264,225,545
	Non-Distribution Asset	60,577,508	-0	60,577,508	0
	Unclassified Asset	3,479,834,283	3,479,834,283	-0	0
	Liability	-1,659,628,088	-1,659,628,088	-0	0
	Equity	-624,687,569	-624,687,569	-0	0
	Sales of Electricity	-2,385,231,893	-0	-0	-2,385,231,893
	Distribution Services Revenue	-1,304,763	-0	-0	-1,304,763
	Late Payment Charges	-4,073,815	-0	-0	-4,073,815
	Specific Service Charges	-1,924,769	-0	-0	-1,924,769
	Other Distribution Revenue	-12,154,882	-0	-0	-12,154,882
	Other Revenue - Unclassified	-0	-0	-0	0
	Other Income & Deductions	10,115,873	10,115,873	-0	0
	Power Supply Expenses (Working Capital)	1,960,852,577	-0	-0	1,960,852,577
	Other Power Supply Expenses	-0	-0	-0	0
	Operation (Working Capital)	36,685,396	-0	-0	36,685,396
	Maintenance (Working Capital)	20,452,699	-0	-0	20,452,699
	Billing and Collection (Working Capital)	21,986,243	-0	-0	21,986,243
	Community Relations (Working Capital)	4,046,362	-0	-0	4,046,362
	Community Relations - CDM (Working Capital)	45,984	-0	-0	45,984
	Administrative and General Expenses (Working Capital)	44,748,422	-0	-0	44,748,422
	Insurance Expense (Working Capital)	2,845,633	-0	-0	2,845,633
	Bad Debt Expense (Working Capital)	11,101,942	-0	-0	11,101,942
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	121,993,910	-0	-0	121,993,910
	Other Amortization - Unclassified	-0	-0	-0	0
	Interest Expense - Unclassifed	73,485,276	73,485,276	-0	0
	Income Tax Expense - Unclassified	4,352,880	4,352,880	-0	0
	Other Distribution Expenses	12,384,049	-0	-0	12,384,049
	Non-Distribution Expenses	-0	-0	-0	0
	Unclassified Expenses	1,453,132	1,453,132	-0	0
		2,716,840,252	1,284,925,787	60,577,508	1,371,336,957

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2003 Total $	2003 Unclassified $	2003 Non-Distribution $	2003 Distribution $
	GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)				
	Land and Buildings	53,440,553	-0	-0	53,440,553
	TS Primary Above 50	-0	-0	-0	0
	DS	132,514,041	-0	-0	132,514,041
	Poles, Wires	1,877,191,532	-0	-0	1,877,191,532
	Line Transformers	453,226,664	-0	-0	453,226,664
	Services and Meters	132,659,239	-0	-0	132,659,239
	General Plant	107,917,080	-0	-0	107,917,080
	Equipment	110,196,592	-0	-0	110,196,592
	IT Assets	117,355,156	-0	-0	117,355,156
	CDM Expenditures and Recoveries	-0	-0	-0	0
	Other Distribution Assets	50,051,883	-0	-0	50,051,883
	Contributions and Grants	-93,747,720	-0	-0	-93,747,720
	Accumulated Amortization	-1,375,557,940	-0	-0	-1,375,557,940
	Non-Distribution Asset	23,652,698	-0	23,652,698	0
	Unclassified Asset	3,642,738,698	3,642,738,698	-0	0
	Liability	-1,606,319,049	-1,606,319,049	-0	0
	Equity	-694,746,130	-694,746,130	-0	0
	Sales of Electricity	-2,374,634,874	-0	-0	-2,374,634,874
	Distribution Services Revenue	-2,621,810	-0	-0	-2,621,810
	Late Payment Charges	-5,354,355	-0	-0	-5,354,355
	Specific Service Charges	-2,560,439	-0	-0	-2,560,439
	Other Distribution Revenue	-9,389,353	-0	-0	-9,389,353
	Other Revenue - Unclassified	-0	-0	-0	0
	Other Income & Deductions	-14,425,060	-14,425,060	-0	0
	Power Supply Expenses (Working Capital)	1,934,499,821	-0	-0	1,934,499,821
	Other Power Supply Expenses	-0	-0	-0	0
	Operation (Working Capital)	38,222,276	-0	-0	38,222,276
	Maintenance (Working Capital)	22,752,336	-0	-0	22,752,336
	Billing and Collection (Working Capital)	22,758,483	-0	-0	22,758,483
	Community Relations (Working Capital)	2,393,963	-0	-0	2,393,963
	Community Relations - CDM (Working Capital)	2,468	-0	-0	2,468
	Administrative and General Expenses (Working Capital)	50,204,521	-0	-0	50,204,521
	Insurance Expense (Working Capital)	3,088,223	-0	-0	3,088,223
	Bad Debt Expense (Working Capital)	6,554,665	-0	-0	6,554,665
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	117,682,139	-0	-0	117,682,139
	Other Amortization - Unclassified	-0	-0	-0	0
	Interest Expense - Unclassifed	80,134,453	80,134,453	-0	0
	Income Tax Expense - Unclassified	41,711,220	41,711,220	-0	0
	Other Distribution Expenses	13,183,239	-0	-0	13,183,239
	Non-Distribution Expenses	-0	-0	-0	0
	Unclassified Expenses	-0	-0	-0	0
		2,854,775,215	1,449,094,133	23,652,698	1,382,028,384

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (RP-2005-0020/EB-2005-0421)

August 2 2005

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2004 Total $	2004 Unclassified $	2004 Non-Distribution $	2004 Distribution $
GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)					
	Land and Buildings	51,834,925	-0	-0	51,834,925
	TS Primary Above 50	-0	-0	-0	0
	DS	138,170,824	-0	-0	138,170,824
	Poles, Wires	1,945,939,014	-0	-0	1,945,939,014
	Line Transformers	485,117,456	-0	-0	485,117,456
	Services and Meters	146,869,319	-0	-0	146,869,319
	General Plant	105,141,912	-0	-0	105,141,912
	Equipment	109,339,635	-0	-0	109,339,635
	IT Assets	123,878,146	-0	-0	123,878,146
	CDM Expenditures and Recoveries	2,509,800	-0	-0	2,509,800
	Other Distribution Assets	52,465,688	-0	-0	52,465,688
	Contributions and Grants	-122,266,801	-0	-0	-122,266,801
	Accumulated Amortization	-1,492,463,699	-0	-0	-1,492,463,699
	Non-Distribution Asset	18,248,294	-0	18,248,294	0
	Unclassified Asset	3,787,339,850	3,787,339,850	-0	0
	Liability	-1,617,620,228	-1,617,620,228	-0	0
	Equity	-706,950,674	-706,950,674	-0	0
	Sales of Electricity	-2,235,154,525	-0	-0	-2,235,154,525
	Distribution Services Revenue	-2,526,206	-0	-0	-2,526,206
	Late Payment Charges	-4,606,068	-0	-0	-4,606,068
	Specific Service Charges	-2,118,862	-0	-0	-2,118,862
	Other Distribution Revenue	-10,139,286	-0	-0	-10,139,286
	Other Revenue - Unclassified	-0	-0	-0	0
	Other Income & Deductions	-17,617,156	-17,617,156	-0	0
	Power Supply Expenses (Working Capital)	1,798,008,676	-0	-0	1,798,008,676
	Other Power Supply Expenses	-0	-0	-0	0
	Operation (Working Capital)	40,610,016	-0	-0	40,610,016
	Maintenance (Working Capital)	23,582,147	-0	-0	23,582,147
	Billing and Collection (Working Capital)	24,493,813	-0	-0	24,493,813
	Community Relations (Working Capital)	2,600,372	-0	-0	2,600,372
	Community Relations - CDM (Working Capital)	-0	-0	-0	0
	Administrative and General Expenses (Working Capital)	48,221,010	-0	-0	48,221,010
	Insurance Expense (Working Capital)	3,330,532	-0	-0	3,330,532
	Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	122,525,812	-0	-0	122,525,812
	Other Amortization - Unclassified	-0	-0	-0	0
	Interest Expense - Unclassifed	81,607,659	81,607,659	-0	0
	Income Tax Expense - Unclassified	43,824,981	43,824,981	-0	0
	Other Distribution Expenses	13,746,906	-0	-0	13,746,906
	Non-Distribution Expenses	-0	-0	-0	0
	Unclassified Expenses	-0	-0	-0	0
		2,966,148,917	1,570,584,434	18,248,294	1,377,316,190

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

1-1 GENERAL (Input)

Enter general information related to the Application

Version:	2
Name of Applicant	Toronto Hydro-Electric System Limited
License Number	ED-2002-0497
File Number(s)	EB-2005-0020
Contact:	
Name	Anthony Lam
e-mail	ALAM@torontohydro.com
telephone	416-542-2876
Date of Application:	August 2 2005

The following questions relate to the applicability of the EDR 2006 Model's components and will help define the Model Navigation. Although, the answers can be updated at any time it will be more efficient to determine the correct responses before proceeding to use the Model.

PLEASE ANSWER EACH QUESTION USING THE "INPUT" BUTTONS ON THE LEFT.

	Yes/No	
Unadjusted Option: Will you be submitting your application using unadjusted amounts?	Yes	
Tier 2 Adjustments: Will the application include Tier 2 adjustments.?	No	to Sheet ADJ 2 to Sheet ADJ 4
Are you required to change your rate structure for Unmetered Scattered Loads? (Handbook 10.2)	No	
Do you give an allowance for Transformer Ownership?(Handbook 10.4)	Yes	
Service Territorites with Differerent Rates for Similar Customers?	No	to Sheet 6-1
Enter the Number of Services Territories for Similar Customers.	1	

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	ADJUSTED 2004 Total	2004 Unclassified	2004 Non-Distribution	2004 Distribution
		$	$	$	$
	GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)				
	Land and Buildings	51,834,925	-0	-0	51,834,925
	TS Primary Above 50	-0	-0	-0	0
	DS	138,170,824	-0	-0	138,170,824
	Poles, Wires	1,945,939,014	-0	-0	1,945,939,014
	Line Transformers	485,117,456	-0	-0	485,117,456
	Services and Meters	146,869,319	-0	-0	146,869,319
	General Plant	105,141,912	-0	-0	105,141,912
	Equipment	109,339,635	-0	-0	109,339,635
	IT Assets	123,878,146	-0	-0	123,878,146
	CDM Expenditures and Recoveries	2,509,800	-0	-0	2,509,800
	Other Distribution Assets	52,465,688	-0	-0	52,465,688
	Contributions and Grants	-122,266,801	-0	-0	-122,266,801
	Accumulated Amortization	-1,492,463,699	-0	-0	-1,492,463,699
	Non-Distribution Asset	18,248,294	-0	18,248,294	0
	Unclassified Asset	759,786,389	759,786,389	-0	0
	Liability	-1,617,620,228	-1,617,620,228	-0	0
	Equity	-706,950,674	-706,950,674	-0	0
	Sales of Electricity	-2,235,154,525	-0	-0	-2,235,154,525
	Distribution Services Revenue	-0	-0	-0	0
	Late Payment Charges	-4,606,068	-0	-0	-4,606,068
	Specific Service Charges	-1,654,517	-0	-0	-1,654,517
	Other Distribution Revenue	-12,384,790	-0	-0	-12,384,790
	Other Revenue - Unclassified	-1,263,014	-1,263,014	-0	0
	Other Income & Deductions	-10,648,815	-10,648,815	-0	0
	Power Supply Expenses (Working Capital)	1,798,008,676	-0	-0	1,798,008,676
	Other Power Supply Expenses	-0	-0	-0	0
	Operation (Working Capital)	40,089,820	-0	-0	40,089,820
	Maintenance (Working Capital)	23,630,973	-0	-0	23,630,973
	Billing and Collection (Working Capital)	25,086,159	-0	-0	25,086,159
	Community Relations (Working Capital)	2,630,975	-0	-0	2,630,975
	Community Relations - CDM (Working Capital)	-0	-0	-0	0
	Administrative and General Expenses (Working Capital)	42,268,549	-0	-0	42,268,549
	Insurance Expense (Working Capital)	3,330,532	-0	-0	3,330,532
	Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	122,525,812	-0	-0	122,525,812
	Other Amortization - Unclassified	-0	-0	-0	0
	Interest Expense - Unclassifed	81,607,659	81,607,659	-0	0
	Income Tax Expense - Unclassified	49,675,434	49,675,434	-0	0
	Other Distribution Expenses	7,896,453	-0	-0	7,896,453
	Non-Distribution Expenses	-0	-0	-0	0
	Unclassified Expenses	-0	-0	-0	0
		-60,755,052	-1,445,413,249	18,248,294	1,366,409,903

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Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

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2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	ADJUSTED 2004 Total	2004 Unclassified	2004 Non-Distribution	2004 Distribution
		$	$	$	$
	SUMMARY FINANCIAL INFORMATION				
	(Before Adjustments)				
	DISTRIBUTION ASSETS:				
	Land and Buildings	51,834,925	-0	-0	51,834,925
	TS Primary Above 50	-0	-0	-0	0
	DS	138,170,824	-0	-0	138,170,824
	Poles, Wires	1,945,939,014	-0	-0	1,945,939,014
	Line Transformers	485,117,456	-0	-0	485,117,456
	Services and Meters	146,869,319	-0	-0	146,869,319
	General Plant	105,141,912	-0	-0	105,141,912
	Equipment	109,339,635	-0	-0	109,339,635
	IT Assets	123,878,146	-0	-0	123,878,146
	CDM Assets		-0	-0	0
	Other Distribution Assets	52,465,688	-0	-0	52,465,688
	Contributions and Grants	-122,266,801	-0	-0	-122,266,801
	TOTAL DISTRIBUTION ASSETS	**3,036,490,117**	**-0**	**-0**	**3,036,490,118**
	NET FIXED DISTRIBUTION ASSETS:				
	Total Distribution Assets (as above) - LESS:				
	Accumulated Amortization	-1,492,463,699	-0	-0	-1,492,463,699
	NET FIXED DISTRIBUTION ASSETS	**1,544,026,418**	**-0**	**-0**	**1,544,026,419**
	NET SALES REVENUE				
	Sales of Electricity	-2,235,154,525	-0	-0	-2,235,154,525
	Power Supply Expenses (Working Capital)	1,798,008,676	-0	-0	1,798,008,676
	SALES OF ELECTRICITY NET OF COST OF POWER	-437,145,849	-0	-0	-437,145,849
	DISTRIBUTION REVENUE				
	Distribution Services Revenue	-0	-0	-0	0
	Late Payment Charges	-4,606,068	-0	-0	-4,606,068
	Specific Service Charges	-1,654,517	-0	-0	-1,654,517
	Other Distribution Revenue	-12,384,790	-0	-0	-12,384,790
	TOTAL DISTRIBUTION REVENUE	**-18,645,374**	**-0**	**-0**	**-18,645,374**
	DISTRIBUTION EXPENSES (before PILS):				
	Operation (Working Capital)	40,089,820	-0	-0	40,089,820
	Maintenance (Working Capital)	23,630,973	-0	-0	23,630,973
	Billing and Collection (Working Capital)	25,086,159	-0	-0	25,086,159
	Community Relations (Working Capital)	2,630,975	-0	-0	2,630,975
	Community Relations - CDM (Working Capital)	-0	-0	-0	0
	Administrative and General Expenses (Working Capital)	42,268,549	-0	-0	42,268,549
	Insurance Expense (Working Capital)	3,330,532	-0	-0	3,330,532
	Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	122,525,812	-0	-0	122,525,812
	Other Distribution Expenses	7,896,453	-0	-0	7,896,453
	TOTAL DISTRIBUTION EXPENSES (before PILs)	**275,664,908**	**-0**	**-0**	**275,664,908**
	WORKING CAPITAL CALCULATION				
	Cost of Power				
	Power Supply Expenses (Working Capital)	1,798,008,676			
	TOTAL COST OF POWER	1,798,008,676			
	Expenses				
	Operation (Working Capital)	40,089,820			
	Maintenance (Working Capital)	23,630,973			
	Billing and Collection (Working Capital)	25,086,159			
	Community Relations (Working Capital)	2,630,975			
	Community Relations - CDM (Working Capital)	-0			
	Administrative and General Expenses (Working Capital)	42,268,549			
	Insurance Expense (Working Capital)	3,330,532			
	Bad Debt Expense (Working Capital)	8,205,635			
	Advertising Expenses	-0			
	Charitable Contributions	-0			
	Other Distribution Expenses	7,896,453			
	TOTAL EXPENSES	153,139,096			
	TOTAL FOR WORKING CAPITAL CALCULATION	**1,951,147,771**			

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Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

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2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2005 Total $	2005 Unclassified $	2005 Non-Distribution $	2005 Distribution $
GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)					
	Land and Buildings	52,625,744	-0	-0	52,625,744
	TS Primary Above 50	-0	-0	-0	0
	DS	144,384,630	-0	-0	144,384,630
	Poles, Wires	2,021,078,019	-0	-0	2,021,078,019
	Line Transformers	518,053,944	-0	-0	518,053,944
	Services and Meters	148,901,861	-0	-0	148,901,861
	General Plant	107,000,256	-0	-0	107,000,256
	Equipment	115,138,980	-0	-0	115,138,980
	IT Assets	132,595,300	-0	-0	132,595,300
	CDM Expenditures and Recoveries	2,509,800	-0	-0	2,509,800
	Other Distribution Assets	56,490,857	-0	-0	56,490,857
	Contributions and Grants	-138,547,678	-0	-0	-138,547,678
	Accumulated Amortization	-1,619,558,680	-0	-0	-1,619,558,680
	Non-Distribution Asset	21,863,041	-0	21,863,041	0
	Unclassified Asset	689,678,729	689,678,729	-0	0
	Liability	-1,610,560,268	-1,610,560,268	-0	0
	Equity	-706,950,750	-706,950,750	-0	0
	Sales of Electricity	-2,386,026,566	-0	-0	-2,386,026,566
	Distribution Services Revenue	-0	-0	-0	0
	Late Payment Charges	-4,606,068	-0	-0	-4,606,068
	Specific Service Charges	-1,654,517	-0	-0	-1,654,517
	Other Distribution Revenue	-12,384,789	-0	-0	-12,384,789
	Other Revenue - Unclassified	-1,263,014	-1,263,014	-0	0
	Other Income & Deductions	-10,648,815	-10,648,815	-0	0
	Power Supply Expenses (Working Capital)	1,910,181,727	-0	-0	1,910,181,727
	Other Power Supply Expenses	-0	-0	-0	0
	Operation (Working Capital)	40,658,707	-0	-0	40,658,707
	Maintenance (Working Capital)	23,864,830	-0	-0	23,864,830
	Billing and Collection (Working Capital)	25,501,913	-0	-0	25,501,913
	Community Relations (Working Capital)	2,570,049	-0	-0	2,570,049
	Community Relations - CDM (Working Capital)	-0	-0	-0	0
	Administrative and General Expenses (Working Capital)	46,704,343	-0	-0	46,704,343
	Insurance Expense (Working Capital)	3,031,707	-0	-0	3,031,707
	Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	127,053,000	-0	-0	127,053,000
	Other Amortization - Unclassified	-0	-0	-0	0
	Interest Expense - Unclassifed	81,607,659	81,607,659	-0	0
	Income Tax Expense - Unclassified	49,675,434	49,675,434	-0	0
	Other Distribution Expenses	7,896,453	-0	-0	7,896,453
	Non-Distribution Expenses	-0	-0	-0	0
	Unclassified Expenses	-0	-0	-0	0
		-154,928,531	-1,508,461,025	21,863,040	1,331,669,454

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2005 Total	2005 Unclassified	2005 Non-Distribution	2005 Distribution
		$	$	$	$

SUMMARY FINANCIAL INFORMATION

(Before Adjustments)

DISTRIBUTION ASSETS:

	Total	Unclassified	Non-Distribution	Distribution
Land and Buildings	52,625,744	-0	-0	52,625,744
TS Primary Above 50	-0	-0	-0	0
DS	144,384,630	-0	-0	144,384,630
Poles, Wires	2,021,078,019	-0	-0	2,021,078,019
Line Transformers	518,053,944	-0	-0	518,053,944
Services and Meters	148,901,861	-0	-0	148,901,861
General Plant	107,000,256	-0	-0	107,000,256
Equipment	115,138,980	-0	-0	115,138,980
IT Assets	132,595,300	-0	-0	132,595,300
CDM Assets	2,509,800	-0	-0	2,509,800
Other Distribution Assets	56,490,857	-0	-0	56,490,857
Contributions and Grants	-138,547,678	-0	-0	-138,547,678
TOTAL DISTRIBUTION ASSETS	**3,160,231,712**	**-0**	**-0**	**3,160,231,712**

NET FIXED DISTRIBUTION ASSETS:

	Total	Unclassified	Non-Distribution	Distribution
Total Distribution Assets (as above) - LESS:				
Accumulated Amortization	-1,619,558,680	-0	-0	-1,619,558,680
NET FIXED DISTRIBUTION ASSETS	**1,540,673,031**	**-0**	**-0**	**1,540,673,032**

NET SALES REVENUE

	Total	Unclassified	Non-Distribution	Distribution
Sales of Electricity	-2,386,026,566	-0	-0	-2,386,026,566
Power Supply Expenses (Working Capital)	1,910,181,727	-0	-0	1,910,181,727
SALES OF ELECTRICITY NET OF COST OF POWER	-475,844,840	-0	-0	-475,844,840

DISTRIBUTION REVENUE

	Total	Unclassified	Non-Distribution	Distribution
Distribution Services Revenue	-0	-0	-0	0
Late Payment Charges	-4,606,068	-0	-0	-4,606,068
Specific Service Charges	-1,654,517	-0	-0	-1,654,517
Other Distribution Revenue	-12,384,789	-0	-0	-12,384,789
TOTAL DISTRIBUTION REVENUE	**-18,645,374**	**-0**	**-0**	**-18,645,374**

DISTRIBUTION EXPENSES (before PILS):

	Total	Unclassified	Non-Distribution	Distribution
Operation (Working Capital)	40,658,707	-0	-0	40,658,707
Maintenance (Working Capital)	23,864,830	-0	-0	23,864,830
Billing and Collection (Working Capital)	25,501,913	-0	-0	25,501,913
Community Relations (Working Capital)	2,570,049	-0	-0	2,570,049
Community Relations - CDM (Working Capital)	-0	-0	-0	0
Administrative and General Expenses (Working Capital)	46,704,343	-0	-0	46,704,343
Insurance Expense (Working Capital)	3,031,707	-0	-0	3,031,707
Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
Advertising Expenses	-0	-0	-0	0
Charitable Contributions	-0	-0	-0	0
Amortization of Assets	127,053,000	-0	-0	127,053,000
Other Distribution Expenses	7,896,453	-0	-0	7,896,453
TOTAL DISTRIBUTION EXPENSES (before PILs)	**285,486,636**	**-0**	**-0**	**285,486,636**

WORKING CAPITAL CALCULATION

Cost of Power

	Total
Power Supply Expenses (Working Capital)	1,910,181,727
TOTAL COST OF POWER	1,910,181,727

Expenses

	Total
Operation (Working Capital)	40,658,707
Maintenance (Working Capital)	23,864,830
Billing and Collection (Working Capital)	25,501,913
Community Relations (Working Capital)	2,570,049
Community Relations - CDM (Working Capital)	-0
Administrative and General Expenses (Working Capital)	46,704,343
Insurance Expense (Working Capital)	3,031,707
Bad Debt Expense (Working Capital)	8,205,635
Advertising Expenses	-0
Charitable Contributions	-0
Other Distribution Expenses	7,896,453
TOTAL EXPENSES	158,433,636
TOTAL FOR WORKING CAPITAL CALCULATION	**2,068,615,362**

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2006 Total	2006 Unclassified	2006 Non-Distribution	2006 Distribution
		$	$	$	$
GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)					
	Land and Buildings	53,100,497	-0	-0	53,100,497
	TS Primary Above 50	-0	-0	-0	0
	DS	151,276,672	-0	-0	151,276,672
	Poles, Wires	2,124,040,520	-0	-0	2,124,040,520
	Line Transformers	545,977,762	-0	-0	545,977,762
	Services and Meters	204,772,166	-0	-0	204,772,166
	General Plant	108,200,754	-0	-0	108,200,754
	Equipment	117,783,559	-0	-0	117,783,559
	IT Assets	152,027,332	-0	-0	152,027,332
	CDM Expenditures and Recoveries	2,509,800	-0	-0	2,509,800
	Other Distribution Assets	62,181,058	-0	-0	62,181,058
	Contributions and Grants	-160,547,678	-0	-0	-160,547,678
	Accumulated Amortization	-1,748,071,341	-0	-0	-1,748,071,341
	Non-Distribution Asset	28,100,632	-0	28,100,632	0
	Unclassified Asset	704,934,139	704,934,139	-0	0
	Liability	-1,593,622,803	-1,593,622,803	-0	0
	Equity	-706,950,750	-706,950,750	-0	0
	Sales of Electricity	-2,378,844,917	-0	-0	-2,378,844,917
	Distribution Services Revenue	-0	-0	-0	0
	Late Payment Charges	-4,606,068	-0	-0	-4,606,068
	Specific Service Charges	-5,416,360	-0	-0	-5,416,360
	Other Distribution Revenue	-9,705,989	-0	-0	-9,705,989
	Other Revenue - Unclassified	-1,439,681	-1,439,681	-0	0
	Other Income & Deductions	-3,324,338	-3,324,338	-0	0
	Power Supply Expenses (Working Capital)	1,888,698,691	-0	-0	1,888,698,691
	Other Power Supply Expenses	-0	-0	-0	0
	Operation (Working Capital)	43,149,584	-0	-0	43,149,584
	Maintenance (Working Capital)	24,063,304	-0	-0	24,063,304
	Billing and Collection (Working Capital)	26,062,817	-0	-0	26,062,817
	Community Relations (Working Capital)	2,854,982	-0	-0	2,854,982
	Community Relations - CDM (Working Capital)	-0	-0	-0	0
	Administrative and General Expenses (Working Capital)	48,337,283	-0	-0	48,337,283
	Insurance Expense (Working Capital)	3,100,000	-0	-0	3,100,000
	Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	128,513,000	-0	-0	128,513,000
	Other Amortization - Unclassified	-0	-0	-0	0
	Interest Expense - Unclassifed	81,607,659	81,607,659	-0	0
	Income Tax Expense - Unclassified	49,675,434	49,675,434	-0	0
	Other Distribution Expenses	7,896,453	-0	-0	7,896,453
	Non-Distribution Expenses	-0	-0	-0	0
	Unclassified Expenses	-0	-0	-0	0
		-45,460,194	-1,469,120,340	28,100,631	1,395,559,515

2-2 UNADJUSTED ACCOUNTING DATA

All adjustments are entered on subsequent sheets.

Account Number	Account Description	2006 Total $	2006 Unclassified $	2006 Non-Distribution $	2006 Distribution $
	SUMMARY FINANCIAL INFORMATION				
	(Before Adjustments)				
	DISTRIBUTION ASSETS:				
	Land and Buildings	53,100,497	-0	-0	53,100,497
	TS Primary Above 50	-0	-0	-0	0
	DS	151,276,672	-0	-0	151,276,672
	Poles, Wires	2,124,040,520	-0	-0	2,124,040,520
	Line Transformers	545,977,762	-0	-0	545,977,762
	Services and Meters	204,772,166	-0	-0	204,772,166
	General Plant	108,200,754	-0	-0	108,200,754
	Equipment	117,783,559	-0	-0	117,783,559
	IT Assets	152,027,332	-0	-0	152,027,332
	CDM Assets	2,509,800	-0	-0	2,509,800
	Other Distribution Assets	62,181,058	-0	-0	62,181,058
	Contributions and Grants	-160,547,678	-0	-0	-160,547,678
	TOTAL DISTRIBUTION ASSETS	**3,361,322,442**	**-0**	**-0**	**3,361,322,442**
	NET FIXED DISTRIBUTION ASSETS:				
	Total Distribution Assets (as above) - LESS:				
	Accumulated Amortization	-1,748,071,341	-0	-0	-1,748,071,341
	NET FIXED DISTRIBUTION ASSETS	**1,613,251,101**	**-0**	**-0**	**1,613,251,101**
	NET SALES REVENUE				
	Sales of Electricity	-2,378,844,917	-0	-0	-2,378,844,917
	Power Supply Expenses (Working Capital)	1,888,698,691	-0	-0	1,888,698,691
	SALES OF ELECTRICITY NET OF COST OF POWER	-490,146,226	-0	-0	-490,146,226
	DISTRIBUTION REVENUE				
	Distribution Services Revenue	-0	-0	-0	0
	Late Payment Charges	-4,606,068	-0	-0	-4,606,068
	Specific Service Charges	-5,416,360	-0	-0	-5,416,360
	Other Distribution Revenue	-9,705,989	-0	-0	-9,705,989
	TOTAL DISTRIBUTION REVENUE	**-19,728,417**	**-0**	**-0**	**-19,728,417**
	DISTRIBUTION EXPENSES (before PILS):				
	Operation (Working Capital)	43,149,584	-0	-0	43,149,584
	Maintenance (Working Capital)	24,063,304	-0	-0	24,063,304
	Billing and Collection (Working Capital)	26,062,817	-0	-0	26,062,817
	Community Relations (Working Capital)	2,854,982	-0	-0	2,854,982
	Community Relations - CDM (Working Capital)	-0	-0	-0	0
	Administrative and General Expenses (Working Capital)	48,337,283	-0	-0	48,337,283
	Insurance Expense (Working Capital)	3,100,000	-0	-0	3,100,000
	Bad Debt Expense (Working Capital)	8,205,635	-0	-0	8,205,635
	Advertising Expenses	-0	-0	-0	0
	Charitable Contributions	-0	-0	-0	0
	Amortization of Assets	128,513,000	-0	-0	128,513,000
	Other Distribution Expenses	7,896,453	-0	-0	7,896,453
	TOTAL DISTRIBUTION EXPENSES (before PILs)	**292,183,057**	**-0**	**-0**	**292,183,057**
	WORKING CAPITAL CALCULATION				
	Cost of Power				
	Power Supply Expenses (Working Capital)	1,888,698,691			
	TOTAL COST OF POWER	1,888,698,691			
	Expenses				
	Operation (Working Capital)	43,149,584			
	Maintenance (Working Capital)	24,063,304			
	Billing and Collection (Working Capital)	26,062,817			
	Community Relations (Working Capital)	2,854,982			
	Community Relations - CDM (Working Capital)	-0			
	Administrative and General Expenses (Working Capital)	48,337,283			
	Insurance Expense (Working Capital)	3,100,000			
	Bad Debt Expense (Working Capital)	8,205,635			
	Advertising Expenses	-0			
	Charitable Contributions	-0			
	Other Distribution Expenses	7,896,453			
	TOTAL EXPENSES	163,670,057			
	TOTAL FOR WORKING CAPITAL CALCULATION	**2,052,368,748**			

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ADJ 1 (RATE BASE -TIER 1)

			posted to account
6) Adjustment to Cost of Power as Recorded in Trial Balance			
Adjustment for "Normalized" Cost of Power	**(Handbook 5.4)**		
Cost of Power - 2006 Amount	1,888,698,691		
Consumption per customer: Ratio of three year average vs. 2004 (calculated from figures in Sheet 6-2)	0.9969		
No Adjustments for Future Test Year	**0.0000**	**0**	
Accounting Adjustment			
Normalized Cost of Power (re. above)	1,888,698,691		
Total Adjustment to Cost of Power		**0**	4710 - Cost of Power Adjustments
Total Tier 1 and Other Adjustments to the Rate Base		**0**	

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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)	104,360		
[above items to Sheet 5-5 B.R.R. #2]			
Adjustment		**104,360**	5665 - Miscellaneous General Expenses

ADJ 5 (SPECIFIC DISTRIBUTION EXPENSES)

Description	HANDBOOK REF.	2004 Expenses $	2005 Expenses $	2006 Expenses $	Non-Recoverable 2004 Amounts $
INSURANCE EXPENSE	6.2.1	3,330,532	3,031,707	3,100,000	
3rd Party Insurance					
Type & Number of Insurers					
Property / Boiler & Machinery		523,446	500,000	**600,000**	
Primary Liability		419,040	405,000	**425,000**	
Excess Liability		807,840	883,707	**1,000,000**	
Garage Liability		0	18,000	**20,000**	
Automobile Liability		0	0	**0**	
Directors & Officers		120,780	130,000	**150,000**	
Excess D&O		86,850	90,000	**100,000**	
Crime		22,687	22,000	**25,000**	
Social Club Liability		0	0	**0**	
Travel Accident		0	0	**0**	
Aon Reed Stenhouse		0	108,000	**120,000**	
Claims paid		250,000	475,000	**660,000**	
Claims reserved		1,100,000	400,000	**0**	
Errors & Ommissions -- THESI		17,510	0	**0**	
Primary Liability -- THTI		249	0	**0**	
Auto Policy Rebate		-17,870	0	**0**	
Claims reserved					
Total - 3rd Party Insurance		3,330,532	3,031,707	**3,100,000**	**0**
BAD DEBT EXPENSE	6.2.2	8,205,635	8,205,635	8,205,635	
Residential		4,259,357	4,258,914	**4,258,914**	
All General Service (we only keep statistics this class level)		3,947,497	3,947,086	**3,947,086**	
Others (non-energy related accounts)		-1,219			
Total Bad Debt		8,205,635	8,206,000	**8,206,000**	**0**

Material Bad Debt Occurrences

Materiality (0.2% x Distribtn. Expenses) = 584,366

ADJ 5 (SPECIFIC DISTRIBUTION EXPENSES)

Description	HANDBOOK REF.	2004 Expenses $	2005 Expenses $	2006 Expenses $	Non-Recoverable 2004 Amounts $
ADVERTISING, ETC.	6.2.4				
Advertising Expenses		0	0	0	
Political Contributions					
Employee Dues		131,488			
Charitable Contributions		0	0	0	
Amount of recoverable contributions *(details to be put in Schedule 6-3)*					
Other Contributions *(non-recoverable)*					0
PENSION AND POST-RETIREMENT BENEFITS	6.2.6	0	0	0	
OMERS Members					
Total of OMERS Pension Premiums and Adjustments		7,835,353			0
TOTAL NON-RECOVERABLE AMOUNT					0

2-4 ADJUSTED ACCOUNTING DATA

ok

Acct. No.	Account Description	2006 Distribution (Before Adjustments) (from INPUT 2) $	Accounts as Adjusted - Application $	Board Adjustment + $	Board Adjustment - (enter as a negative amount) $	2006 Accounts as Adjusted for 2006 Rate Calculation [and average of 03/04 for dist. assets & wkg. cap. allow. calc.] $
	GROUPED INPUT FOR CALCULATIONS: (Minimum Reporting Requirement)					
	Land and Buildings	53,100,497	53,100,497	0	0	52,863,120
	TS Primary Above 50	0	0	0	0	0
	DS	151,276,672	151,276,672	0	0	147,830,651
	Poles, Wires	2,124,040,520	2,124,040,520	0	0	2,072,559,269
	Line Transformers	545,977,762	545,977,762	0	0	532,015,853
	Services and Meters	204,772,166	204,772,166	0	0	176,837,013
	General Plant	108,200,754	108,200,754	0	0	107,600,505
	Equipment	117,783,559	117,783,559	0	0	116,461,269
	IT Assets	152,027,332	152,027,332	0	0	142,311,316
	CDM Expenditures and Recoveries	2,509,800	2,509,800	0	0	2,509,800
	Other Distribution Assets	62,181,058	62,181,058	0	0	59,335,958
	Contributions and Grants	-160,547,678	-160,547,678	0	0	-149,547,678
	Accumulated Amortization	-1,748,071,341	-1,748,071,341	0	0	-1,683,815,011
	Non-Distribution Asset	0	0	0	0	0
	Unclassified Asset	0	0	0	0	0
	Liability	0	0	0	0	0
	Equity	0	0	0	0	0
	Sales of Electricity	-2,378,844,917	-2,378,844,917	0	0	-2,378,844,917
	Distribution Services Revenue	0	0	0	0	0
	Late Payment Charges	-4,606,068	-4,606,068	0	0	-4,606,068
	Specific Service Charges	-5,416,360	-5,416,360	0	0	-5,416,360
	Other Distribution Revenue	-9,705,989	-9,705,989	0	0	-9,705,989
	Other Revenue - Unclassified	0	0	0	0	0
	Other Income & Deductions	-3,324,338	-3,324,338	0	0	-3,324,338
	Power Supply Expenses (Working Capital)	1,888,698,691	1,888,698,691	0	0	1,888,698,691
	Other Power Supply Expenses	0	0	0	0	0
	Operation (Working Capital)	43,149,584	43,149,584	0	0	43,149,584
	Maintenance (Working Capital)	24,063,304	24,063,304	0	0	24,063,304
	Billing and Collection (Working Capital)	26,062,817	26,062,817	0	0	26,062,817
	Community Relations (Working Capital)	2,854,982	2,854,982	0	0	2,854,982
	Community Relations - CDM (Working Capital)	0	0	0	0	0
	Administrative and General Expenses (Working Capital)	48,337,283	48,337,283	0	0	48,337,283
	Insurance Expense (Working Capital)	3,100,000	3,100,000	0	0	3,100,000
	Bad Debt Expense (Working Capital)	8,205,635	8,205,635	0	0	8,205,635
	Advertising Expenses	0	0	0	0	0
	Charitable Contributions	0	0	0	0	0
	Amortization of Assets	128,513,000	128,513,000	0	0	128,513,000
	Other Amortization - Unclassified	0	0	0	0	0
	Interest Expense - Unclassifed	0	0	0	0	0
	Income Tax Expense - Unclassified	0	0	0	0	0
	Other Distribution Expenses	7,896,453	7,896,453	0	0	7,896,453
	Non-Distribution Expenses	0	0	0	0	0
	Unclassified Expenses	0	0	0	0	0
		1,392,235,177	1,392,235,177	0	0	1,355,946,142

ok

Acct. No.	Account Description	2006 Distribution (Before Adjustments)	Accounts as Adjusted - Application	Board Adjustment	Board Adjustment	2006 Accounts as Adjusted for 2006 Rate Calculation
		(from INPUT 2)		+	- (enter as a negative amount)	[and average of 03/04 for dist. assets & wkg. cap. allow. calc.]
		$	$	$	$	$
	SUMMARY FINANCIAL INFORMATION					
	DISTRIBUTION ASSETS:					
	Land and Buildings	53,100,497	53,100,497	0	0	52,863,120
	TS Primary Above 50	0	0	0	0	0
	DS	151,276,672	151,276,672	0	0	147,830,651
	Poles, Wires	2,124,040,520	2,124,040,520	0	0	2,072,559,269
	Line Transformers	545,977,762	545,977,762	0	0	532,015,853
	Services and Meters	204,772,166	204,772,166	0	0	176,837,013
	General Plant	108,200,754	108,200,754	0	0	107,600,505
	Equipment	117,783,559	117,783,559	0	0	116,461,269
	IT Assets	152,027,332	152,027,332	0	0	142,311,316
	CDM Assets	2,509,800	2,509,800	0	0	2,509,800
	Other Distribution Assets	62,181,058	62,181,058	0	0	59,335,958
	Contributions and Grants	-160,547,678	-160,547,678	0	0	-149,547,678
	TOTAL DISTRIBUTION ASSETS	**3,361,322,442**	**3,361,322,442**	**0**	**0**	**3,260,777,077**
	NET FIXED DISTRIBUTION ASSETS:					
	Total Distribution Assets (as above) - LESS:					
	Accumulated Amortization	-1,748,071,341	-1,748,071,341	0	0	-1,683,815,011
	NET FIXED DISTRIBUTION ASSETS	**1,613,251,101**	**1,613,251,101**	**0**	**0**	**1,576,962,066**
	NET SALES REVENUE					
	Sales of Electricity	-2,378,844,917	-2,378,844,917	0	0	-2,378,844,917
	Power Supply Expenses (Working Capital)	1,888,698,691	1,888,698,691	0	0	1,888,698,691
	SALES OF ELECTRICITY NET OF COST OF POWER	-490,146,226	-490,146,226	0	0	-490,146,226
	DISTRIBUTION REVENUE					
	Distribution Services Revenue	0	0	0	0	0
	Late Payment Charges	-4,606,068	-4,606,068	0	0	-4,606,068
	Specific Service Charges	-5,416,360	-5,416,360	0	0	-5,416,360
	Other Distribution Revenue	-9,705,989	-9,705,989	0	0	-9,705,989
	TOTAL DISTRIBUTION REVENUE	**-19,728,417**	**-19,728,417**	**0**	**0**	**-19,728,417**
	DISTRIBUTION EXPENSES (before PILS):					
	Operation (Working Capital)	43,149,584	43,149,584	0	0	43,149,584
	Maintenance (Working Capital)	24,063,304	24,063,304	0	0	24,063,304
	Billing and Collection (Working Capital)	26,062,817	26,062,817	0	0	26,062,817
	Community Relations (Working Capital)	2,854,982	2,854,982	0	0	2,854,982
	Community Relations - CDM (Working Capital)	0	0	0	0	0
	Administrative and General Expenses (Working Capital)	48,337,283	48,337,283	0	0	48,337,283
	Insurance Expense (Working Capital)	3,100,000	3,100,000	0	0	3,100,000
	Bad Debt Expense (Working Capital)	8,205,635	8,205,635	0	0	8,205,635
	Advertising Expenses	0	0	0	0	0
	Charitable Contributions	0	0	0	0	0
	Amortization of Assets	128,513,000	128,513,000	0	0	128,513,000
	Other Distribution Expenses	7,896,453	7,896,453	0	0	7,896,453
	TOTAL DISTRIBUTION EXPENSES (before PILs)	**292,183,057**	**292,183,057**	**0**	**0**	**292,183,057**
	PILS AMOUNT					
	WORKING CAPITAL CALCULATION					
	Cost of Power					
	Power Supply Expenses (Working Capital)	1,888,698,691	1,888,698,691	0	0	1,888,698,691
	TOTAL COST OF POWER	1,888,698,691	1,888,698,691	0	0	1,888,698,691
	Expenses					
	Operation (Working Capital)	43,149,584	43,149,584	0	0	43,149,584
	Maintenance (Working Capital)	24,063,304	24,063,304	0	0	24,063,304
	Billing and Collection (Working Capital)	26,062,817	26,062,817	0	0	26,062,817
	Community Relations (Working Capital)	2,854,982	2,854,982	0	0	2,854,982
	Community Relations - CDM (Working Capital)	-0	-0	0	0	0
	Administrative and General Expenses (Working Capital)	48,337,283	48,337,283	0	0	48,337,283
	Insurance Expense (Working Capital)	3,100,000	3,100,000	0	0	3,100,000
	Bad Debt Expense (Working Capital)	8,205,635	8,205,635	0	0	8,205,635
	Advertising Expenses	-0	-0	0	0	0
	Charitable Contributions	-0	-0	0	0	0
	Other Distribution Expenses	7,896,453	7,896,453	0	0	7,896,453
	TOTAL EXPENSES	163,670,057	163,670,057	0	0	163,670,057
	TOTAL FOR WORKING CAPITAL CALCULATION	**2,052,368,748**	**2,052,368,748**	**0**	**0**	**2,052,368,748**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

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2-5 CAPITAL EXPENDITURES

This schedule is provided to assist with completion of Schedule 4-1 by identifying accounts which may have projects in scope.

The information at the top of the sheet is based on the trial balance data and is provided to assist in completing Schedule 4-1.

Please See Schedule 4-1 for Details	**Grouping**

3.4.8 - Employee Total Compensation

EXECUTIVE CATEGORY

Year	Number of FTEs	Average Yearly Base Wage	Average Yearly Overtime	Average Yearly Incentive	Average Yearly Benefits
2004	19.0	$ 128,349	$ -	$ 42,143	$ 70,615
2005	16.0	$ 165,172		$ 52,875	$ 56,520
2006	16.0	$ 174,061		$ 56,532	$ 66,051

MANAGEMENT CATEGORY

Year	Number of FTEs	Average Yearly Base Wage	Average Yearly Overtime	Average Yearly Incentive	Average Yearly Benefits
2004	49.0	$ 100,004	$ -	$ 12,441	$ 31,618
2005	42.0	$ 114,106		$ 14,841	$ 34,710
2006	44.0	$ 116,815		$ 15,003	$ 38,047

NON-UNIONIZED CATEGORY

Year	Number of FTEs	Average Yearly Base Wage	Average Yearly Overtime	Average Yearly Incentive	Average Yearly Benefits
2004	284.0	$ 78,723	$ 2,807	$ 4,356	$ 25,329
2005	318.0	$ 82,219		$ 4,268	$ 25,988
2006	328.0	$ 83,886		$ 5,080	$ 26,513

UNIONIZED CATEGORY

Year	Number of FTEs	Average Yearly Base Wage	Average Yearly Overtime	Average Yearly Incentive	Average Yearly Benefits
2004	1212.0	$ 63,079	$ 4,699	$ 81	$ 22,435
2005	1192.0	$ 64,542	$ 6,072		$ 22,503
2006	1192.0	$ 66,664	$ 6,490		$ 23,300

Toronto Hydro-Electric System Limited

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3-1 RATE BASE

Net Fixed Assets		**1,576,962,066**
Working Capital Allowance		
Working Capital *(from Sheet "2-4 ADJUSTED ACCOUNTING DATA")*	2,052,368,748	
Working Capital Allowance @ 15%	307,855,312	**307,855,312**
RATE BASE		**1,884,817,378**

Fixed Assets for Conservation and Demand Management[1]	0
Smart Meters	0

[1] Include reference to Board-Approved CDM Application

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Toronto Hydro-Electric System Limited

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3-2 COST OF CAPITAL (Input)

Cost of Capital

Deemed Debt Rate and D/E Structures

Rate Base: (from Sheet *Ratebase Calc.*)	$1,884,817,378
Size of LDC (based on Rate Base)	Large
Debt Rate (based on Size)	5.80%
Deemed Debt (based on Size)	65%
Deemed Equity (based on Size)	35%

Table 3-1
Deemed Common Equity and Debt Ratios and Debt Cost Rates

Size of Utility Rate Base	Descriptor	Equity CER %	Debt (1-CER)%	DR
Greater than $1.0 Billion	Large	35%	65%	5.80%
Between $250 Million and $1.0 Billion	Medium-Large	40%	60%	5.90%
Between $100 Million and $250 Million	Medium-Small	45%	55%	6.00%
Under $100 Million	Small	50%	50%	6.25%

Debt Rate (DR)

Deemed or proposed Debt Rate for Revenue Requirement calculation.	6.70%
Weighted debt rate calculated on Weighted Debt Cost (%)	6.70%

Return on Equity

Utility's Proposed ROE	9.00%
Allowed ROE for Revenue Requirement Calculation	9.00%
Target ROE per Board Decision	9.00%

Cost of Capital

Cost of Capital	7.51%

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Toronto Hydro-Electric System Limited

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3-3 CAPITAL STRUCTURE (Input)

Schedule 5-2 Actual Capital Structure of the Distributor

Line			Particulars (As of Dec 31 2004)		Deemed Structure (from 3-2)	Cost Rate
			($000)	(%)		
(1)	Long Term Debt		$ 1,160,230,955	62.2%		
(2)	Unfunded Short Term Debt			0.0%		
(3)	Total Debt	(3) = (1) + (2)	$ 1,160,230,955	62.2%	65.0%	
(4)	Preferred Shares			0.0%		
(5)	Common Equity		$ 705,682,000	37.8%		
(6)	Total Equity	(6) = (4) + (5)	$ 705,682,000	37.8%	35.0%	
(7)	Total Rate Base	(6) = (3) + (6)	$ 1,865,912,955.00	100.0%		

Absolute difference between actual and size-related deemed debt ratio: 2.8%

Toronto Hydro-Electric System Limited

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3-4 WEIGHTED DEBT COST (Input)

Schedule 5-1: Weighted Debt Cost

Size of Utility	**Large**	*Small*	*Medium-Small*	*Medium-Large*	*Large*
Deemed Debt Rate					
prior to 2000	**actual rate**	*actual rate*	*actual rate*	*actual rate*	*actual rate*
2000 to 2005	**6.80%**	*7.25%*	*7.00%*	*6.90%*	*6.80%*
2006	**5.80%**	*6.25%*	*6.00%*	*5.90%*	*5.80%*

No.	Description	Debt Holder	Is the Debt Holder Affiliated with the LDC? (Y/N)	Date of Issuance of Debt (Date)	Principal ($)	Term (Years)	Actual Rate (%)	Debt Rate Used for Weighted Debt Rate Cost
1	Long-Term promissory note due	Parent Company (THC)	Y	7-May-2003	$ 980,230,955	10	6.80%	6.80%
2	Long-Term Debentures due 201:	Parent Company (THC)	Y	7-May-2003	$ 180,000,000	10	6.17%	6.17%
	Total				$ 1,160,230,955			
	Weighted Average Debt Cost						**6.70%**	**6.70%**

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Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

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4-1 DATA for PILS MODEL

Item	Source		$ Amount as Adjusted
Net Income before consideration of PILS			
Revenue Requirement other than PILS	*Sheet 5-1*		433,666,299
Distribution Expenses other than PILS and interest *(Note: "Book" interest expense and "book" income tax expense are not included in Distribution Expenses above)*	*Sheet 2-4*		292,183,057 to detail
			141,483,242
Calculated Interest			
Rate Base	*Sheet 3-1*	1,884,817,378	
x Debt Component	*Sheet 3-2*	65.00%	
x Debt Rate reflected in Revenue Requirement	*Sheet 3-2*	6.70%	82,111,495
Target Net Income before consideration of PILS (= Target Net Income reflecting PILS)			**59,371,747**
Specific Distribution Expenses from Sheet ADJ5 (non-recoverable portion)			
Insurance			0
Bad Debt			0
Advertising			0
Political Contributions			0
Employee Dues			0
Charitable Contributions			0

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

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4-2 OUTPUT from PILS MODEL

PILS Amount from PILS Model	$47,634,254

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

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5-1 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.

to Overview

	$	$
Rate Base (*from sheet 3-1)*	1,884,817,378	
x Cost of Capital *(from sheet 3-2)*	7.51%	
Return on Ratebase		**141,483,242**
Distribution Expenses (*from sheet "2-4 ADJUSTED ACCOUNTING DATA"*		**292,183,057**
Revenue Requirement Before Income Taxes		**433,666,299**
Income Taxes - from PILS Model		**47,634,254**
SERVICE REVENUE REQUIREMENT		**481,300,553**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

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5-2 SPECIFIC SERVICE CHARGES (Input)

Rate Code	Description	Standard Amount (Rate) $	Applicable?	Updated Amt. (if applic.) $	Forecast 2006 Volume	Calc'd. Amt. - Std. Formula $	Alternate Amount (if applic.) $	Calc. Method (attach. calc. & justification)	Amount for Rate Calculations $
1	Arrears certificate	15.00	N		0	0.00		Standard	0.00
2	Statement of account	15.00	N		0	0.00		Standard	0.00
3	Pulling post dated cheques	15.00	N		0	0.00		Standard	0.00
4	**Duplicate invoices for previous billing**	15.00	Y		1,000	15,000.00		Standard	**15,000.00**
5	Request for other billing information	15.00	N		0	0.00		Standard	0.00
6	**Easement letter**	15.00	Y		1,200	18,000.00		Standard	**18,000.00**
7	**Income tax letter**	15.00	Y		1,000	15,000.00		Standard	**15,000.00**
8	Notification charge	15.00	N		0	0.00		Standard	0.00
9	Account history	15.00	N		0	0.00		Standard	0.00
10	Credit reference/credit check (plus credit agency costs)	15.00	N		0	0.00		Standard	0.00
11	**Returned cheque charge (plus bank charges)**	15.00	Y		8,000	120,000.00		Standard	**120,000.00**
12	Charge to certify cheque	15.00	N		0	0.00		Standard	0.00
13	Legal letter charge	15.00	N		0	0.00		Standard	0.00
14	**Account set up charge/change of occupancy charge (plus credit agency costs if applicable)**	30.00	Y		95,000	2,850,000.00		Standard	**2,850,000.00**
15	**Special meter reads**	30.00	Y		1,000	30,000.00		Standard	**30,000.00**

5-2 SPECIFIC SERVICE CHARGES (Input)

Rate Code	Description	Standard Amount (Rate) $	Applicable?	Updated Amt. (if applic.) $	Forecast 2006 Volume	Calc'd. Amt. - Std. Formula $	Alternate Amount (if applic.) $	Calc. Method (attach. calc. & justification)	Amount for Rate Calculations $
16	**Collection of account charge - no disconnection**	30.00	Y		60,000	1,800,000.00		Standard	**1,800,000.00**
17	Collection of account charge - no disconnection - after regular hours	165.00	N		0	0.00		Standard	0.00
18	**Disconnect/Reconnect at meter - during regular hours**	65.00	Y		3,500	227,500.00		Standard	**227,500.00**
19	**Install/Remove load control device - during regular hours**	65.00	Y		2,500	162,500.00		Standard	**162,500.00**
20	**Disconnect/Reconnect at meter - after regular hours**	185.00	Y		250	46,250.00		Standard	**46,250.00**
21	**Install/Remove load control device - after regular hours**	185.00	Y		100	18,500.00		Standard	**18,500.00**
22	**Disconnect/Reconnect at pole - during regular hours**	185.00	Y		500	92,500.00		Standard	**92,500.00**
23	**Disconnect/Reconnect at pole - after regular hours**	415.00	Y		50	20,750.00		Standard	**20,750.00**
24	**Meter dispute charge plus Measurement Canada fees (if meter found correct)**	30.00	Y		12	360.00		Standard	**360.00**
25	Service call - customer-owned equipment	30.00	N		0	0.00		Standard	0.00
26	Service call - after regular hours	165.00	N		0	0.00		Standard	0.00
27	Temporary service install & remove - overhead - no transformer	500.00	N		0	0.00		Standard	0.00
28	Temporary service install & remove - underground - no transformer	300.00	N		0	0.00		Standard	0.00
29	Temporary service install & remove - overhead - with transformer	1,000.00	N		0	0.00		Standard	0.00
30	**Specific Charge for Access to the Power Poles $/pole/year**	22.35	Y		57,186	1,278,107.10		Standard	**1,278,107.10**

5-2 SPECIFIC SERVICE CHARGES (Input)

Rate Code	Description	Standard Amount (Rate) $	Applic able?	Updated Amt. (if applic.) $	Forecast 2006 Volume	Calc'd. Amt. - Std. Formula $	Alternate Amount (if applic.) $	Calc. Method (attach. calc. & justification)	Amount for Rate Calculations $
	Additional Charges - Please be Specific								
31	**Specific Charge for Access to the Power Poles $/pole/year (Third Party Attachements on Hydro Poles)**	N/A	Y	18.55	17,782	329,856.10		addnl. chrge	**329,856.10**
32	**Specific Charge for Access to the Power Poles $/pole/year (Hydro Attachements on Third Party Poles)**	N/A	Y	-22.75	7,397	-168,281.75		addnl. chrge	**-168,281.75**
33	**Standby Monthly Backup Admin Charges**	N/A	Y	200.00	60	12,000.00		addnl. chrge	**12,000.00**
34		N/A	N		0	0.00		addnl. chrge	0.00
35		N/A	N		0	0.00		addnl. chrge	0.00
36		N/A	N		0	0.00		addnl. chrge	0.00
37		N/A	N		0	0.00		addnl. chrge	0.00
38		N/A	N		0	0.00		addnl. chrge	0.00
39		N/A	N		0	0.00		addnl. chrge	0.00
40		N/A	N		0	0.00		addnl. chrge	0.00
41		N/A	N		0	0.00		addnl. chrge	0.00
42		N/A	N		0	0.00		addnl. chrge	0.00
43		N/A	N		0	0.00		addnl. chrge	0.00

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5-2 SPECIFIC SERVICE CHARGES (Input)

Rate Code	Description	Standard Amount (Rate) $	Applicable?	Updated Amt. (if applic.) $	Forecast 2006 Volume	Calc'd. Amt. - Std. Formula $	Alternate Amount (if applic.) $	Calc. Method (attach. calc. & justification)	Amount for Rate Calculations $
44		N/A	N		0	0.00		addnl. chrge	0.00
45		N/A	N		0	0.00		addnl. chrge	0.00
46		N/A	N		0	0.00		addnl. chrge	0.00
47		N/A	N		0	0.00		addnl. chrge	0.00
48		N/A	N		0	0.00		addnl. chrge	0.00
49		N/A	N		0	0.00		addnl. chrge	0.00
50		N/A	N		0	0.00		addnl. chrge	0.00
Total Specific Service Charge Revenue						**6,868,041.45**			**6,868,041.45**

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5-3 OTHER REGULATED CHARGES (Input)

Description	HANDBOOK REF.	Charge Determinant			Total $	Comments
RETAIL SERVICES REVENUE						
Establishing Service Agreements	12.2.1					
Distributor-Consolidated Billing	12.2.2				1,757,560	account 4082
Retailer-Consolidated Billing	12.2.3					
SERVICE TRANSACTION REQUEST REVENUES	12.2.4				5,320	account 4084
RPP (formerly SSS)ADMINISTRATION CHARGE REVENUE	12.1					account 4080b
DISTRIBUTION WHEELING SERVICE REVENUE	10.7					account 4080c, if applicable in 2004
OTHER COMPONENTS OF "OTHER DISTRIBUTION REVENUE"					7,943,109	accounts 4090, 4205-4215, 4220, 4240-5
OTHER DISTRIBUTION REVENUE					9,705,989	
Other Rate Information (Optional)						
NON-COMPETITIVE ELECTRICITY CHARGES						
Wholesale Market Service Rate	12.3.1	kWh for customers who are not wholesale market participants	account 4062 -		0	
Retail Transmission Service Rates	12.3.2	exisitng rates				
Network Service Rate			account 4066 -		0	
Connection Service Rate			account 4068 -		0	
Charges Levied by the Government of Ontario	12.3.3		Volume	Rate $		
Rural and Remote Rate Protection (RRRP)		kWh	0	0.0010	0	
Debt Retirement Charge		kWh	0	0.0070	0	

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5-4 CDM (Input)

	$
Trial Balance account 5415-Energy Conservation	0
Tier 1 Adjustment	0
Adjusted amount	0

Portion attributed to specific classes	

5-5 BASE REVENUE REQUIREMENT

to Overview

	$	$
Service Revenue Requirement *(from Sheet 5-1)*		**481,300,553**
LESS:		
Revenue Offsets:		
Board Approved Charges		
Specific Service Charges *(from Sheet 5-2)*	6,868,041	
Late Payment Charges *(from Sheet 2-4 ADJUSTED ACCOUNTING DATA)*	4,606,068	
Other Distribution Revenue *(from Sheet 5-3)*	9,705,989	
Other Income & Deductions *(from Sheet 2-4 ADJUSTED ACCOUNTING DATA)*	3,324,338	
TOTAL REVENUE OFFSETS	24,504,437	**24,504,437**
Base Revenue Requirement		**456,796,116**

(defined as SERVICE REVENUE REQUIREMENT NET OF REVENUE OFFSETS)

Base Revenue Requirement is allocated to classes in three portions:

B.R.R. #1: Base Revenue Requirement net of B.R.R. #2 and #3 (below)	**456,691,756**
B.R.R. #2: Low Voltage Wheeling Costs (Embedded Distributors only) *(from Sheet ADJ3, item 5)*	**104,360**
B.R.R. #3: Directly assigned CDM *(from Sheet 5-4)*	**0**
Base Revenue Requirement (as above)	**456,796,116**

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6-1 CUSTOMER CLASSES (Input)

Enter current and proposed customer classes

Customer Classification		**Current**	**Proposed**
Please update: "X" if applicable (delete if not applicable)			
RESIDENTIAL			X
Regular		X	X
Time of Use		X	
Urban			
Suburban			
Other (specify)			
Other (specify)			
Other (specify)			
Other (specify)			
Other (specify)			
GENERAL SERVICE			X
Less than 50 kW		X	X
Less than 50 kW Time of Use			
Other < 50 kW (specify) .			
50 to 1000 kW - Non Interval		X	X
50 to 1000 kW - Interval		X	X
Other > 50 kW (specify) .			
Other > 50 kW (specify) .			
Other > 50 kW (specify) .			
Intermediate Use	(1000 - 5000 kW)	X	X
Large Use (> 5000 kW) Includes Standby Charges		X	X
Unmetered Scattered Load - Admin per Customer		X	X
Unmetered Scattered Load - Charge per Connection		X	X
Street Lighting		X	X
Back-up/Standby Power		X	X
Other (specify)			
Other (specify)			

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6-2 DEMAND, RATES (Input)

Enter customer numbers and demand data
for 2002, 2003 and 2004

Enter 2004 and 2005 rates

	Number of Customers (Connections)			Demand Data - kWh			Demand Data - kVA		
	2004	2005	2006	2004	2005	2006	2004	2005	2006
	#	#	#	kWh	kWh	kWh	kVA	kVA	kVA
RESIDENTIAL									
Regular	594,976	594,328	597,210	5,428,344,270	5,449,764,661	5,470,966,591			
Time of Use									
GENERAL SERVICE									
Less than 50 kW	66,505	66,514	66,505	2,548,012,246	2,603,748,501	2,620,609,508			
50 to 1000 kW - Non Interval	9,621	9,584	9,550	6,432,544,447	6,444,806,643	6,174,749,298	17,798,349	17,971,650	17,351,203
50 to 1000 kW - Interval	1,525	1,577	1,682	3,346,527,943	3,434,419,197	3,667,466,273	7,646,423	7,910,435	8,472,217
Intermediate Use (1000 - 5000 kW)	498	506	511	4,994,299,814	5,031,547,999	5,080,177,986	11,617,228	11,671,662	11,825,404
Large Use (> 5000 kW) Includes Standby Charges	47	47	47	2,593,568,077	2,564,248,406	2,605,123,574	5,530,030	5,476,780	5,566,486
Unmetered Scattered Load - Admin per Customer	1,557	1,438	1,438	55,842,609	54,397,998	54,396,775			
Unmetered Scattered Load - Charge per Connection	14,450	13,408	13,408	0	0	0	0	0	0
Street Lighting	159,821	159,861	159,861	108,911,280	109,349,579	108,994,196	308,277	317,526	317,526
Back-up/Standby Power							0	0	0
TOTALS	849,000	847,263	850,212	25,508,050,686	25,692,282,983	25,782,484,200	42,900,307	43,348,053	43,532,838

EDR 2006 MODEL (ver. 2)

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6-2 DEMAND, RATES (Input)

Enter customer numbers and demand data for 2002, 2003 and 2004

Enter 2004 and 2005 rates

		2004 Rates "Sheet 2"			2005 Rates "Sheet 5"			2005 Rates "Sheet 9"		
	Volumetric Rate Type	Distribution Rate kWh $	Distribution Rate kVA $	Mthly Service Chrg (Per Cust. or Connection) $	Distribution Rate kWh $	Distribution Rate kVA $	Mthly Service Chrg (Per Cust. or Connection) $	Distribution Rate kWh $	Distribution Rate kVA $	Mthly Service Chrg (Per Cust. or Connection) $
RESIDENTIAL										
Regular	kWh	0.0115		12.23	0.0173		13.64	0.0173		13.64
Time of Use	kWh									
GENERAL SERVICE										
Less than 50 kW	kWh	0.0156		16.40	0.0207		18.27	0.0207		18.27
50 to 1000 kW - Non Interval	kW		4.4253	26.01		5.6425	28.93		5.6425	28.93
50 to 1000 kW - Interval	kW		4.4247	26.17		5.6286	29.23		5.6286	29.23
Intermediate Use (1000 - 5000 kW)	kW		3.6654	720.86		4.6607	803.72		4.6607	803.72
Large Use (> 5000 kW) Includes Standby Charges	kW		3.1345	2,754.27		3.9530	3,070.72		3.9530	3,070.72
Unmetered Scattered Load - Admin per Customer	kWh	0.0156		2.26	0.0201		2.26	0.0201		2.26
Unmetered Scattered Load - Charge per Connection				0.26			0.29			0.29
Street Lighting	kW		3.0101	0.26		4.0763	0.29		4.0763	0.29
Back-up/Standby Power	kW									
TOTALS										

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Toronto Hydro-Electric System Limited

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6-3 Transformer Ownership (Input)

	2004			2005			2006		
	kVA	$/kVA	$	kVA	$/kVA	$	kVA	$/kVA	$
RESIDENTIAL									
Regular			0.00			0.00			0.00
Time of Use			0.00			0.00			0.00
GENERAL SERVICE									
Less than 50 kW			0.00			0.00			0.00
50 to 1000 kW - Non Interval	2,800,155	0.62	1,760,208.84	2,676,344	0.62	1,682,379.58	2,360,760	0.62	1,483,999.83
50 to 1000 kW - Interval	2,201,336	0.62	1,383,784.14	2,337,547	0.62	1,469,408.02	2,607,278	0.62	1,638,964.19
Intermediate Use (1000 - 5000 kW)	8,848,600	0.62	5,562,328.36	8,991,985	0.62	5,652,461.68	9,237,372	0.62	5,806,714.87
Large Use (> 5000 kW) Includes Standby Charges	5,161,143	0.62	3,244,351.90	5,055,163	0.62	3,177,731.63	5,130,213	0.62	3,224,908.71
Unmetered Scattered Load - Admin per Customer			0.00			0.00			0.00
Unmetered Scattered Load - Charge per Connection			0.00			0.00			0.00
Street Lighting			0.00			0.00			0.00
Back-up/Standby Power			0.00			0.00			0.00
TOTALS	19,011,234		11,950,673.24	19,061,039		11,981,980.90	19,335,623		**12,154,587.60**

Toronto Hydro-Electric System Limited

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7-1 ALLOCATION - Base Revenue Requirement

B.R.R. #1 from Sheet 5-5
(not including amounts related to Low Voltage Wheeling Costs and CDM)

Amount allocated on this sheet:--
Base Revenue Requirement B.R.R. #1
$456,691,756

	Number of Customers (Connections)	Calculated kWh per Customer	Calculated kWh	Calculated kVA per Customer	Calculated kVA
	2006 Customer count	2006 average kWh per cust.	2006 cust. count x 2006 average kWh per cust.	2006 average kVA per cust.	2006 cust. count x 2006 average kVA per cust.
RESIDENTIAL					
Regular	597,210	9,160.9	5,470,966,591	0.0	0
Time of Use	0	0.0	0	0.0	0
Less than 50 kW	66,505	39,404.7	2,620,609,508	0.0	0
50 to 1000 kW - Non Interval	9,550	646,570.6	6,174,749,298	1,816.9	17,351,203
50 to 1000 kW - Interval	1,682	2,180,419.9	3,667,466,273	5,037.0	8,472,217
Intermediate Use (1000 - 5000 kW)	511	9,941,639.9	5,080,177,986	23,141.7	11,825,404
Large Use (> 5000 kW) Includes Standby Charges	47	55,428,161.1	2,605,123,574	118,435.9	5,566,486
Unmetered Scattered Load - Admin per Customer	1,438	37,823.5	54,396,775	0.0	0
Unmetered Scattered Load - Charge per Connection	13,408	0.0	0	0.0	0
Street Lighting	159,861	681.8	108,994,196	2.0	317,526
Back-up/Standby Power	0	0.0	0	0.0	0
TOTALS	850,212		25,782,484,200		43,532,838

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric Syst

ED-2002-0497 (EB-2005-0020)

August 2 2005

7-1 ALLOCATION - Base Revenue Requirei

B.R.R. #1 from Sheet 5-5
(not including amounts related to Low Voltage Wheeling Costs and CDM)

Amount allocated on this sheet:--
Base Revenue Requirement B.R.R. #1
$456,691,756

	Calculated Revenue for Allocation to Customer Classes: Consumption determinants x Rates for 2004 test year "Sheet 2"				Allocation to Customer Classes %	Calculated Revenue for Allocation between Fixed and Variable: Consumption determinants x Rates for 2005 "Sheet 5"				Allocation between Fixed and Variable %		
	Volumetric kWh ($)	Volumetric kVA ($)	Monthly Fixed Charges ($)	Total ($)	Total for customer class as % of Total for all classes	Volumetric kWh ($)	Volumetric kVA ($)	Monthly Fixed Charges ($)	Total ($)	Volumetric as percent of Total for customer class	Fixed charges as percent of total for customer class	
RESIDENTIAL												
Regular	63,149,349	0	87,632,185	150,781,534	38.49%	94,587,053	0	97,740,279	192,327,332	49.18%	50.82%	100.00%
Time of Use	0	0	0	0	0.00%	0	0	0	0	0.00%	0.00%	0.00%
Less than 50 kW	40,904,866	0	13,086,785	53,991,651	13.78%	54,295,326	0	14,584,245	68,879,570	78.83%	21.17%	100.00%
50 to 1000 kW - Non Interval	0	76,783,799	2,980,843	79,764,642	20.36%	0	97,903,656	3,315,711	101,219,367	96.72%	3.28%	100.00%
50 to 1000 kW - Interval	0	37,487,119	528,124	38,015,243	9.71%	0	47,686,786	589,949	48,276,735	98.78%	1.22%	100.00%
Intermediate Use (1000 - 5000 kW)	0	43,344,961	4,420,322	47,765,283	12.19%	0	55,114,454	4,928,414	60,042,868	91.79%	8.21%	100.00%
Large Use (> 5000 kW) Includes Standby Charges	0	17,448,261	1,553,407	19,001,668	4.85%	0	22,004,111	1,731,887	23,735,998	92.70%	7.30%	100.00%
Unmetered Scattered Load - Admin per Customer	848,590	0	39,003	887,593	0.23%	1,095,234	0	39,003	1,134,237	96.56%	3.44%	100.00%
Unmetered Scattered Load - Charge per Connection	0	0	41,832	41,832	0.01%	0	0	46,659	46,659	0.00%	100.00%	100.00%
Street Lighting	0	955,798	499,203	1,455,001	0.37%	0	1,294,331	556,505	1,850,835	69.93%	30.07%	100.00%
Back-up/Standby Power	0	0	0	0	0.00%	0	0	0	0	0.00%	0.00%	0.00%
TOTALS	104,902,805	176,019,937	110,781,705	391,704,447	**100.00%**	149,977,612	224,003,338	123,532,651	497,513,602	75.17%	24.83%	**100.00%**

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August 2 2005

7-1 ALLOCATION - Base Revenue Require

B.R.R. #1 from Sheet 5-5
(not including amounts related to Low Voltage Wheeling Costs and CDM)

Amount allocated on this sheet:--
Base Revenue Requirement B.R.R. #1
$456,691,756

	Base Revenue Requirement Allocated (adjusted for Transformer Credit)		
	Overall Allocation to Classes	Variable Component	Fixed Component
RESIDENTIAL			
Regular	180,476,304	88,758,688	91,717,616
Time of Use	0	0	0
Less than 50 kW	64,624,715	50,941,374	13,683,341
50 to 1000 kW - Non Interval	95,473,414	92,345,927	3,127,487
50 to 1000 kW - Interval	45,501,929	44,945,888	556,041
Intermediate Use (1000 - 5000 kW)	57,172,131	52,479,352	4,692,779
Large Use (> 5000 kW) Includes Standby Charges	22,743,838	21,084,344	1,659,494
Unmetered Scattered Load - Admin per Customer	1,062,395	1,025,862	36,533
Unmetered Scattered Load - Charge per Connection	50,070	0	50,070
Street Lighting	1,741,547	1,217,903	523,644
Back-up/Standby Power	0	0	0
TOTALS	**468,846,344**	**352,799,338**	**116,047,006**
	12,154,588	<< Less Transformer Credit	
	456,691,756	<< Base Revenue Req. B.R.R.#1	

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Toronto Hydro-Electric System Limited

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7-2 ALLOCATION - Low Voltage Wheeling Costs

B.R.R. #2 from Sheet 5-5

Amount allocated on this sheet:--
Low Voltage Wheeling Costs B.R.R. #2
$104,360

	Retail Transmission Connection Rate ($) per kWh	Retail Transmission Connection Rate ($) per kVA	Basis for Allocation ($) (rate x volume from 6-2)	Allocation Percentages	Allocated $
RESIDENTIAL					
Regular	0.0047		25,713,542.98	21.89%	22,849
Time of Use	0.0047				
GENERAL SERVICE					
Less than 50 kW	0.0047		12,316,864.69	10.49%	10,945
50 to 1000 kW - Non Interval		1.7700	30,711,629.52	26.15%	27,290
50 to 1000 kW - Interval		1.8000	15,249,991.24	12.99%	13,551
Intermediate Use (1000 - 5000 kW)		1.8600	21,995,252.29	18.73%	19,545
Large Use (> 5000 kW) Includes Standby Charges		1.8900	10,520,659.30	8.96%	9,349
Unmetered Scattered Load - Admin per Customer	0.0047		255,664.84	0.22%	227
Unmetered Scattered Load - Charge per Connection					
Street Lighting		2.1400	679,506.36	0.58%	604
Back-up/Standby Power					
TOTALS			117,443,111.21	100.00%	104,360

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Toronto Hydro-Electric System Limited

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7-3 ALLOCATION - CDM (Input)

B.R.R. #3 from Sheet 5-5

Amount allocated on this sheet:--
Directly Attirbuted CDM *B.R.R. #3*
$0

	CDM Requirement Allocated $
RESIDENTIAL	
Regular	
Time of Use	
GENERAL SERVICE	
Less than 50 kW	
50 to 1000 kW - Non Interval	
50 to 1000 kW - Interval	
Intermediate Use (1000 - 5000 kW)	
Large Use (> 5000 kW) Includes Standby Charges	
Unmetered Scattered Load - Admin per Customer	
Unmetered Scattered Load - Charge per Connection	
Street Lighting	
Back-up/Standby Power	
TOTAL	0
Directly Atrributed CDM per 5-4 and 5-5	0
Difference	0

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Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

8-1 RATES - BASE REVENUE REQUIREMENT

Excluding amounts related to Low Voltage / Wheeling Adjustments (Embedded Distributors) and CDM

	Number of Customers (Connections)	kWh	kVA	Base Revenue Requirement Allocated from Sheet 7-1		Base Rates - Requirement *divided by* consumption for test yr.			
	2006 Customer count	2006 cust. count x 2006 per cust. avg. kWh	2006 cust. count x 2006 yr per cust. avg. kVA	Variable Component	Fixed Component	Volumetric Rate Type	Rate per kWh $	Rate per kVA $ (Adjusted for 30 Days of Service)	Fixed service charge $ (Adjusted for 30 Days of Service)
RESIDENTIAL									
Regular	597,210	5,470,966,591	0	88,758,688	91,717,616	kWh	0.0162	0.0000	12.62
Time of Use	0	0	0	0	0	kWh	0.0000	0.0000	0.00
GENERAL SERVICE									
Less than 50 kW	66,505	2,620,609,508	0	50,941,374	13,683,341	kWh	0.0194	0.0000	16.91
50 to 1000 kW - Non Interval	9,550	6,174,749,298	17,351,203	92,345,927	3,127,487	kW	0.0000	5.2493	26.92
50 to 1000 kW - Interval	1,682	3,667,466,273	8,472,217	44,945,888	556,041	kW	0.0000	5.2324	27.17
Intermediate Use (1000 - 5000 kW)	511	5,080,177,986	11,825,404	52,479,352	4,692,779	kW	0.0000	4.3771	754.81
Large Use (> 5000 kW) Includes Standby Charges	47	2,605,123,574	5,566,486	21,084,344	1,659,494	kW	0.0000	3.7358	2902.06
Unmetered Scattered Load - Admin per Customer	1,438	54,396,775	0	1,025,862	36,533	kWh	0.0189	0.0000	2.09
Unmetered Scattered Load - Charge per Connection	13,408	0	0	0	50,070 *	kWh	0.0000	0.0000	0.31
Street Lighting	159,861	108,994,196	317,526	1,217,903	523,644	kW	0.0000	3.7831	0.27
Back-up/Standby Power	0	0	0	0	0	kW	0.0000	0.0000	0.00
TOTALS	850,212	25,782,484,200	43,532,838	**352,799,338**	**116,047,006**				

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8-2 RATES - Low Voltage/ Wheeling Adjustments

	LV/ Wheeling Adj. Allocated	Calculated kWh	Calculated kVA	Volumetric Rate Type	LV/ Wheeling Adj. Rates ($) per kWh	LV/ Wheeling Adj. Rates ($) per kVA
	from Sheet 7-2	from Sheet 7-1	from Sheet 7-1	from Sheet 6-2		
RESIDENTIAL						
Regular	22,849	5,470,966,591		kWh	0.0000	
Time of Use				kWh		
GENERAL SERVICE						
Less than 50 kW	10,945	2,620,609,508		kWh	0.0000	
50 to 1000 kW - Non Interval	27,290	6,174,749,298	17,351,203	kW		0.0016
50 to 1000 kW - Interval	13,551	3,667,466,273	8,472,217	kW		0.0016
Intermediate Use (1000 - 5000 kW)	19,545	5,080,177,986	11,825,404	kW		0.0017
Large Use (> 5000 kW) Includes Standby Charges	9,349	2,605,123,574	5,566,486	kW		0.0017
Unmetered Scattered Load - Admin per Customer	227	54,396,775		kWh	0.0000	
Unmetered Scattered Load - Charge per Connection						
Street Lighting	604	108,994,196	317,526	kW		0.0019
Back-up/Standby Power				kW		
TOTALS	104,360	25,782,484,200	43,532,838			

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8-3 RATES - CDM

	CDM Requirement Allocated	Calculated kWh	Calculated kVA	Volumetric Rate Type	CDM Rates ($) per kWh	CDM Rates ($) per kVA
	from Sheet 7-3	from Sheet 7-1	from Sheet 7-1	from Sheet 6-2		
RESIDENTIAL						
Regular		5,470,966,591		kWh		
Time of Use				kWh		
GENERAL SERVICE						
Less than 50 kW		2,620,609,508		kWh		
50 to 1000 kW - Non Interval		6,174,749,298	17,351,203	kW		
50 to 1000 kW - Interval		3,667,466,273	8,472,217	kW		
Intermediate Use (1000 - 5000 kW)		5,080,177,986	11,825,404	kW		
Large Use (> 5000 kW) Includes Standby Charges		2,605,123,574	5,566,486	kW		
Unmetered Scattered Load - Admin per Customer		54,396,775		kWh		
Unmetered Scattered Load - Charge per Connection						
Street Lighting		108,994,196	317,526	kW		
Back-up/Standby Power				kW		
TOTALS		25,782,484,200	43,532,838			

8-4 RATE RIDERS - Regulatory Assets And Deferred OMERS and OEB Fees

	Regulatory Assets Rate Riders ($) per kWh (Adjusted for 30 Days of Service)	Regulatory Assets Rate Riders ($) per kVA (Adjusted for 30 Days of Service)
RESIDENTIAL		
Regular	0.0032	
Time of Use		
GENERAL SERVICE		
Less than 50 kW	0.0015	
50 to 1000 kW - Non Interval		0.3100
50 to 1000 kW - Interval		0.0900
Intermediate Use (1000 - 5000 kW)		0.0700
Large Use (> 5000 kW) Includes Standby Charges		0.0700
Unmetered Scattered Load - Admin per Customer	0.0014	
Unmetered Scattered Load - Charge per Connection		
Street Lighting		0.0800
Back-up/Standby Power		

2005 Approved Rate Riders - Regulatory Assets

RESIDENTIAL		
Regular	0.0028	
Time of Use		
GENERAL SERVICE		
Less than 50 kW	0.0012	
50 to 1000 kW - Non Interval		0.2600
50 to 1000 kW - Interval		0.0500
Intermediate Use (1000 - 5000 kW)		0.0400
Large Use (> 5000 kW) Includes Standby Charges		0.0500
Unmetered Scattered Load - Admin per Customer	0.0012	
Unmetered Scattered Load - Charge per Connection		
Street Lighting		0.0300
Back-up/Standby Power		

Rate Riders - 2004 RSVA Balances, Defered Omers And OEB Fees

RESIDENTIAL		
Regular	0.0004	
Time of Use		
GENERAL SERVICE		
Less than 50 kW	0.0003	
Greater than 50 kW (to 1000 kW) Non Interval		0.0500
Greater than 50 kW (to 1000 kW) Interval		0.0400
Intermediate Use (1000 - 5000 kW)		0.0300
Large Use (> 5000 kW)		0.0200
Unmetered Scattered Load - Admin per Customer	0.0002	
Unmetered Scattered Load - Charge per Connection		
Street Lighting		0.0500
Back-up/Standby Power		

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8-5 DISTRIBUTION RATES

		Calculated Rates ($)								
		Rate per kWh				Rate per kVA				Fixed Service Charge
	Volumetric Rate Type	Base (from 8-1)	LV/ Wheeling (from 8-2)	CDM (from 8-3)	Combined	Base (from 8-1)	LV/ Wheeling (from 8-2)	CDM (from 8-3)	Combined	Base (from 8-1)
RESIDENTIAL										
Regular	kWh	0.0162	0.0000		0.0162					12.62
Time of Use	kWh									
GENERAL SERVICE										
Less than 50 kW	kWh	0.0194	0.0000		0.0194					16.91
50 to 1000 kW - Non Interval	kW					5.2493	0.0016		5.2508	26.92
50 to 1000 kW - Interval	kW					5.2324	0.0016		5.2340	27.17
Intermediate Use (1000 - 5000 kW)	kW					4.3771	0.0017		4.3787	754.81
Large Use (> 5000 kW) Includes Standby Charges	kW					3.7358	0.0017		3.7375	2,902.06
Unmetered Scattered Load - Admin per Customer	kWh	0.0189	0.0000		0.0189					2.09
Unmetered Scattered Load - Charge per Connection	kWh									0.31
Street Lighting	kW					3.7831	0.0019		3.7850	0.27
Back-up/Standby Power	kW									
TOTALS										

8-5 DISTRIBUTION RATES

	Direct Rate Mitigation ($)			Rate Application ($)				
	Rate per kWh	Rate per kVA	Fixed Service Charge	Rate per kWh	Rate per kVA	Fixed Service Charge	Regulatory Assets per kWh (from 8-4)	Regulatory Assets per kVA (from 8-4)
	Enter only as applicable to override a calculated rate.							
RESIDENTIAL								
Regular				0.0162		12.62	0.0032	
Time of Use								
GENERAL SERVICE								
Less than 50 kW				0.0194		16.91	0.0015	
50 to 1000 kW - Non Interval					5.2500	26.92		0.3100
50 to 1000 kW - Interval					5.2300	27.17		0.0900
Intermediate Use (1000 - 5000 kW)					4.3800	754.81		0.0700
Large Use (> 5000 kW) Includes Standby Charges					3.7400	2,902.06		0.0700
Unmetered Scattered Load - Admin per Customer				0.0189		2.09	0.0014	
Unmetered Scattered Load - Charge per Connection						0.31		
Street Lighting					3.7800	0.27		0.0800
Back-up/Standby Power								
TOTALS								

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8-6 RETAIL TRANSMISSION RATES (Input)

Please indicate on Sheet 1-1 if application is being made for the revised RTS rates (Network and/or Connection)

	Retail Transmission Rate per kWh					
	Retail Tranmission Rate $/kWh			Increment $/kWh		Adjusted Retail Tranmission Rate $
	Network	Connection	Total	Network	Connection	per KWh
RESIDENTIAL						
Regular	0.0057	0.0047	0.0104		(0.0002)	0.0102
Time of Use	0.0057	0.0047	0.0104		(0.0002)	0.0102
GENERAL SERVICE						
Less than 50 kW	0.0058	0.0047	0.0105		(0.0002)	0.0103
50 to 1000 kW - Non Interval						
50 to 1000 kW - Interval						
Intermediate Use (1000 - 5000 kW)						
Large Use (> 5000 kW) Includes Standby Charges						
Unmetered Scattered Load - Admin per Customer	0.0058	0.0047	0.0105		(0.0002)	0.0103
Unmetered Scattered Load - Charge per Connection						
Street Lighting						
Back-up/Standby Power						

	Network	Connection
Total 2006 Cost	$ 137,593,494.85	$ 106,538,890.19
Total 2006 Revenue	$ 137,593,494.85	$ 112,077,419.00
Variance	**$ -**	**$ (5,538,528.81)**
Cost / Revenue Ratio	1.00	0.95

8-6 RETAIL TRANSMISSION RATES (Input)

Please indicate on Sheet 1-1 if application is be
the revised RTS rates (Network and/or Connect

	Retail Transmission Rate per kW					
	Retail Tranmission Rate $/kW			Increment $		Adjusted Retail Tranmission Rate $
	Network	Connection	Total	Network	Connection	per KW
RESIDENTIAL						
Regular						
Time of Use						
GENERAL SERVICE						
Less than 50 kW						
50 to 1000 kW - Non Interval	2.2300	1.7700	4.0000		-0.0875	3.9100
50 to 1000 kW - Interval	2.2700	1.8000	4.0700		-0.0890	3.9800
Intermediate Use (1000 - 5000 kW)	2.4000	1.8600	4.2600		-0.0919	4.1700
Large Use (> 5000 kW) Includes Standby Charges	2.5000	1.8900	4.3900		-0.0934	4.3000
Unmetered Scattered Load - Admin per Customer						
Unmetered Scattered Load - Charge per Connection						
Street Lighting	2.7500	2.1400	4.8900		-0.1058	4.7800
Back-up/Standby Power						

Total 2006 Cost	
Total 2006 Revenue	
Variance	
Cost / Revenue Ratio	

8-7 OTHER CHGS, COMMOD (Input)

Rates assumed - Please update if you have more accurate estimates for your utility.

	Other Charges per kWh ($)					Other Charges per kW ($)					Cost of Power Commodity per kWh ($)		Loss Adjustment Factor	
	Retail Transmission Rate (from 8-6)	Wholesale Market Service Rate	Debt Reduction Charge	Total	Total with Adjusted RTR	Retail Transmission Rate (from 8-6)	Wholesale Market Service Rate	Debt Reduction Charge	Total	Total with Adjusted RTR	up to 1000 kWh	over 1000 kWh	2005	Updated
	per KWh	per KWh	per KWh	per KWh	per KWh	per KW	per KW	per KW	per KW	per KW	per kWh	per kWh		
RESIDENTIAL														
Regular	0.0104	0.0062	0.0070	0.0236	0.0234						0.0500	0.0580	1.0376	1.0376
Time of Use	0.0104	0.0062	0.0070	0.0236	0.0234						0.0500	0.0580	1.0376	1.0376
GENERAL SERVICE														
Less than 50 kW	0.0105	0.0062	0.0070	0.0237	0.0235						0.0500	0.0580	1.0376	1.0376
50 to 1000 kW - Non Interval		0.0062	0.0070	0.0132	0.0132	4.0000			4.0000	3.9100	0.0550	0.0580	1.0376	1.0376
50 to 1000 kW - Interval		0.0062	0.0070	0.0132	0.0132	4.0700			4.0700	3.9800	0.0550	0.0550	1.0376	1.0376
Intermediate Use (1000 - 5000 kW)		0.0062	0.0070	0.0132	0.0132	4.2600			4.2600	4.1700	0.0550	0.0550	1.0376	1.0376
Large Use (> 5000 kW) Includes Standby Charges		0.0062	0.0070	0.0132	0.0132	4.3900			4.3900	4.3000	0.0550	0.0550	1.0040	1.0040
Unmetered Scattered Load - Admin per Customer	0.0105			0.0105	0.0103								1.0085	1.0085
Unmetered Scattered Load - Charge per Connection											0.0550	0.0550	1.0376	1.0376
Street Lighting		0.0062	0.0070	0.0132	0.0132	4.8900			4.8900	4.7800	0.0550	0.0550	1.0376	1.0376
Back-up/Standby Power													1.0376	1.0376

Loss Factors (enter in columns T and U)

	2005	Updated
Supply Facilities Loss Factor	1.0045	1.0045
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0330	1.0330
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	1.0141	1.0141
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0227	1.0227
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0040	1.0040
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0376	1.0376
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0187	1.0187
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0273	1.0273
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0085	1.0085

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9-1 BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-4.58
100 kWh	Distribution (kWh)	100	**0.0173**	1.73	100	**0.0162**	1.62	-0.11	-6.14	-0.48
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	100	0.0028	0.28	100	0.0032	0.32	0.04		0.18
	Sub-Total			**15.65**			**14.57**	**-1.08**	**-6.91**	**-4.88**
	Other Charges (kWh)	104	0.0236	2.45	104	0.0234	2.43	-0.02	-0.85	-0.09
	Cost of Power Commodity (kWh)	104	0.0500	5.19	104	0.0500	5.19	0.00	0.00	0.00
	Total Bill			**23.28**			**22.18**	**-1.10**	**-4.74**	**-4.97**

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-2.78
250 kWh	Distribution (kWh)	250	**0.0173**	4.32	250	**0.0162**	4.06	-0.27	-6.14	-0.73
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	250	0.0028	0.70	250	0.0032	0.80	0.10		0.27
	Sub-Total			**18.66**			**17.48**	**-1.18**	**-6.33**	**-3.23**
	Other Charges (kWh)	259	0.0236	6.12	259	0.0234	6.07	-0.05	-0.85	-0.14
	Cost of Power Commodity (kWh)	259	0.0500	12.97	259	0.0500	12.97	0.00	0.00	0.00
	Total Bill			**37.75**			**36.52**	**-1.23**	**-3.27**	**-3.38**

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-1.68
500 kWh	Distribution (kWh)	500	**0.0173**	8.64	500	**0.0162**	8.11	-0.53	-6.14	-0.88
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	500	0.0028	1.40	500	0.0032	1.60	0.20		0.33
	Sub-Total			**23.68**			**22.34**	**-1.35**	**-5.68**	**-2.23**
	Other Charges (kWh)	519	0.0236	12.24	519	0.0234	12.14	-0.10	-0.85	-0.17
	Cost of Power Commodity (kWh)	519	0.0500	25.94	519	0.0500	25.94	0.00	0.00	0.00
	Total Bill			**61.87**			**60.42**	**-1.45**	**-2.34**	**-2.40**

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9-1 BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL Regular

Consumption: 750 kWh, 0 kW	2005 BILL Volume	2005 BILL RATE $	2005 BILL CHARGE $	2006 BILL Volume	2006 BILL RATE $	2006 BILL CHARGE $	IMPACT $	IMPACT %	IMPACT % of Total Bill
Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-1.20
Distribution (kWh)	750	**0.0173**	12.97	750	**0.0162**	12.17	-0.80	-6.14	-0.94
Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
Regulatory Assets (kWh)	750	0.0028	2.10	750	0.0032	2.40	0.30		0.36
Sub-Total			**28.71**			**27.19**	**-1.51**	**-5.27**	**-1.79**
Other Charges (kWh)	778	0.0236	18.37	778	0.0234	18.21	-0.16	-0.85	-0.18
Cost of Power Commodity (kWh)	778	0.0500	38.91	778	0.0500	38.91	0.00	0.00	0.00
Total Bill			**85.98**			**84.32**	**-1.67**	**-1.94**	**-1.98**

RESIDENTIAL Regular

Consumption: 1,000 kWh, 0 kW	2005 BILL Volume	2005 BILL RATE $	2005 BILL CHARGE $	2006 BILL Volume	2006 BILL RATE $	2006 BILL CHARGE $	IMPACT $	IMPACT %	IMPACT % of Total Bill
Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-0.94
Distribution (kWh)	1,000	**0.0173**	17.29	1,000	**0.0162**	16.23	-1.06	-6.14	-0.98
Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
Regulatory Assets (kWh)	1,000	0.0028	2.80	1,000	0.0032	3.20	0.40		0.37
Sub-Total			**33.73**			**32.05**	**-1.68**	**-4.97**	**-1.55**
Other Charges (kWh)	1,038	0.0236	24.49	1,038	0.0234	24.28	-0.21	-0.85	-0.19
Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
Cost of Power Commodity (kW)	38	0.0580	2.18	38	0.0580	2.18	0.00	0.00	0.00
Total Bill			**110.40**			**108.52**	**-1.88**	**-1.71**	**-1.74**

RESIDENTIAL Regular

Consumption: 1,500 kWh, 0 kW	2005 BILL Volume	2005 BILL RATE $	2005 BILL CHARGE $	2006 BILL Volume	2006 BILL RATE $	2006 BILL CHARGE $	IMPACT $	IMPACT %	IMPACT % of Total Bill
Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-0.63
Distribution (kWh)	1,500	**0.0173**	25.93	1,500	**0.0162**	24.34	-1.59	-6.14	-0.99
Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
Regulatory Assets (kWh)	1,500	0.0028	4.20	1,500	0.0032	4.80	0.60		0.37
Sub-Total			**43.77**			**41.76**	**-2.01**	**-4.59**	**-1.25**
Other Charges (kWh)	1,556	0.0236	36.73	1,556	0.0234	36.42	-0.31	-0.85	-0.19
Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
Cost of Power Commodity (kW)	556	0.0580	32.28	556	0.0580	32.28	0.00	0.00	0.00
Total Bill			**162.78**			**160.46**	**-2.32**	**-1.42**	**-1.45**

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9-1 BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			13.64			12.62	-1.02	-7.45	-0.48
2,000 kWh	Distribution (kWh)	2,000	**0.0173**	34.58	2,000	**0.0162**	32.46	-2.12	-6.14	-1.00
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	2,000	0.0028	5.60	2,000	0.0032	6.40	0.80		0.38
	Sub-Total			**53.82**			**51.48**	**-2.34**	**-4.34**	**-1.10**
	Other Charges (kWh)	2,075	0.0236	48.98	2,075	0.0234	48.56	-0.42	-0.85	-0.20
	Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	1,075	0.0580	62.37	1,075	0.0580	62.37	0.00	0.00	0.00
	Total Bill			**215.16**			**212.41**	**-2.75**	**-1.28**	**-1.30**

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			18.27			16.91	-1.36	-7.46	-1.19
1,000 kWh	Distribution (kWh)	1,000	**0.0207**	20.72	1,000	**0.0194**	19.40	-1.32	-6.36	-1.15
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	1,000	0.0012	1.20	1,000	0.0015	1.50	0.30		0.26
	Sub-Total			**40.19**			**37.81**	**-2.38**	**-5.93**	**-2.08**
	Other Charges (kWh)	1,038	0.0237	24.59	1,038	0.0235	24.38	-0.21	-0.84	-0.18
	Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Total Bill			**116.97**			**114.38**	**-2.59**	**-2.21**	**-2.26**

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			18.27			16.91	-1.36	-7.46	-0.62
2,000 kWh	Distribution (kWh)	2,000	**0.0207**	41.44	2,000	**0.0194**	38.80	-2.64	-6.36	-1.20
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	2,000	0.0012	2.40	2,000	0.0015	3.00	0.60		0.27
	Sub-Total			**62.11**			**58.71**	**-3.40**	**-5.48**	**-1.55**
	Other Charges (kWh)	2,075	0.0237	49.18	2,075	0.0235	48.77	-0.42	-0.84	-0.19
	Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	1,075	0.0580	62.37	1,075	0.0580	62.37	0.00	0.00	0.00
	Total Bill			**223.66**			**219.85**	**-3.82**	**-1.71**	**-1.74**

9-1 BILL IMPACTS *(Monthly Consumptions)*

GENERAL SERVICE Less than 50 kW

Consumption
5,000 kWh
0 kW

	2005 BILL			2006 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.25
Distribution (kWh)	5,000	**0.0207**	103.59	5,000	**0.0194**	97.00	-6.59	-6.36	-1.23
Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
Regulatory Assets (kWh)	5,000	0.0012	6.00	5,000	0.0015	7.50	1.50		0.28
Sub-Total			**127.87**			**121.41**	**-6.46**	**-5.05**	**-1.20**
Other Charges (kWh)	5,188	0.0237	122.96	5,188	0.0235	121.92	-1.04	-0.84	-0.19
Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
Cost of Power Commodity (kW)	4,188	0.0580	242.92	4,188	0.0580	242.92	0.00	0.00	0.00
Total Bill			**543.75**			**536.25**	**-7.49**	**-1.38**	**-1.40**

GENERAL SERVICE Less than 50 kW

Consumption
10,000 kWh
0 kW

	2005 BILL			2006 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.13
Distribution (kWh)	10,000	**0.0207**	207.19	10,000	**0.0194**	194.00	-13.19	-6.36	-1.24
Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
Regulatory Assets (kWh)	10,000	0.0012	12.00	10,000	0.0015	15.00	3.00		0.28
Sub-Total			**237.46**			**225.91**	**-11.55**	**-4.86**	**-1.09**
Other Charges (kWh)	10,376	0.0237	245.92	10,376	0.0235	243.85	-2.08	-0.84	-0.20
Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
Cost of Power Commodity (kW)	9,376	0.0580	543.84	9,376	0.0580	543.84	0.00	0.00	0.00
Total Bill			**1,077.22**			**1,063.59**	**-13.62**	**-1.26**	**-1.28**

GENERAL SERVICE Less than 50 kW

Consumption
15,000 kWh
0 kW

	2005 BILL			2006 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.09
Distribution (kWh)	15,000	**0.0207**	310.78	15,000	**0.0194**	291.00	-19.78	-6.36	-1.24
Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
Regulatory Assets (kWh)	15,000	0.0012	18.00	15,000	0.0015	22.50	4.50		0.28
Sub-Total			**347.05**			**330.41**	**-16.64**	**-4.80**	**-1.05**
Other Charges (kWh)	15,565	0.0237	368.88	15,565	0.0235	365.77	-3.11	-0.84	-0.20
Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
Cost of Power Commodity (kW)	14,565	0.0580	844.75	14,565	0.0580	844.75	0.00	0.00	0.00
Total Bill			**1,610.69**			**1,590.94**	**-19.76**	**-1.23**	**-1.24**

9-1 BILL IMPACTS *(Monthly Consumptions)*

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.12
15,000 kWh	Distribution (kWh)	15,000	**0.0000**	0.00	15,000	**0.0000**	0.00	0.00		0.00
60 kW	Distribution (kW)	60	**5.6425**	338.55	60	**5.2500**	315.00	-23.55	-6.96	-1.38
	Regulatory Assets (kW)	60	0.2600	15.60	60	0.3100	18.60	3.00		0.18
	Sub-Total			**383.08**			**360.52**	**-22.56**	**-5.89**	**-1.32**
	Other Charges (kWh)	15,565	0.0132	205.45	15,565	0.0132	205.45	0.00	0.00	0.00
	Other Charges (kW)	62	4.0000	249.04	62	3.9100	243.43	-5.60	-2.25	-0.33
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	15,565	0.0580	902.75	15,565	0.0580	902.75	0.00	0.00	0.00
	Total Bill			**1,740.33**			**1,712.16**	**-28.17**	**-1.62**	**-1.65**

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.05
40,000 kWh	Distribution (kWh)	40,000	**0.0000**	0.00	40,000	**0.0000**	0.00	0.00		0.00
100 kW	Distribution (kW)	100	**5.6425**	564.25	100	**5.2500**	525.00	-39.25	-6.96	-1.00
	Regulatory Assets (kW)	100	0.2600	26.00	100	0.3100	31.00	5.00		0.13
	Sub-Total			**619.18**			**582.92**	**-36.26**	**-5.86**	**-0.92**
	Other Charges (kWh)	41,506	0.0132	547.88	41,506	0.0132	547.88	0.00	0.00	0.00
	Other Charges (kW)	104	4.0000	415.06	104	3.9100	405.72	-9.34	-2.25	-0.24
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	41,506	0.0580	2,407.34	41,506	0.0580	2,407.34	0.00	0.00	0.00
	Total Bill			**3,989.46**			**3,943.86**	**-45.60**	**-1.14**	**-1.16**

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.02
100,000 kWh	Distribution (kWh)	100,000	**0.0000**	0.00	100,000	**0.0000**	0.00	0.00		0.00
500 kW	Distribution (kW)	500	**5.6425**	2,821.24	500	**5.2500**	2,625.00	-196.24	-6.96	-1.61
	Regulatory Assets (kW)	500	0.2600	130.00	500	0.3100	155.00	25.00		0.20
	Sub-Total			**2,980.17**			**2,806.92**	**-173.25**	**-5.81**	**-1.42**
	Other Charges (kWh)	103,765	0.0132	1,369.70	103,765	0.0132	1,369.70	0.00	0.00	0.00
	Other Charges (kW)	519	4.0000	2,075.30	519	3.9100	2,028.60	-46.69	-2.25	-0.38
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	103,765	0.0580	6,018.36	103,765	0.0580	6,018.36	0.00	0.00	0.00
	Total Bill			**12,443.52**			**12,223.58**	**-219.95**	**-1.77**	**-1.80**

9-1 BILL IMPACTS *(Monthly Consumptions)*

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.01
400,000 kWh	Distribution (kWh)	400,000	**0.0000**	0.00	400,000	**0.0000**	0.00	0.00		0.00
1,000 kW	Distribution (kW)	1,000	**5.6425**	5,642.47	1,000	**5.2500**	5,250.00	-392.47	-6.96	-1.00
	Regulatory Assets (kW)	1,000	0.2600	260.00	1,000	0.3100	310.00	50.00		0.13
	Sub-Total			**5,931.40**			**5,586.92**	**-344.49**	**-5.81**	**-0.88**
	Other Charges (kWh)	415,059	0.0132	5,478.78	415,059	0.0132	5,478.78	0.00	0.00	0.00
	Other Charges (kW)	1,038	4.0000	4,150.59	1,038	3.9100	4,057.21	-93.39	-2.25	-0.24
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00	#DIV/0!	0.00
	Cost of Power Commodity (kW)	415,059	0.0580	24,073.45	415,059	0.0580	24,073.45	0.00	0.00	0.00
	Total Bill			**39,634.23**			**39,196.35**	**-437.88**	**-1.10**	**-1.12**

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	0.00
1,000,000 kWh	Distribution (kWh)	1,000,000	**0.0000**	0.00	1,000,000	**0.0000**	0.00	0.00		0.00
3,000 kW	Distribution (kW)	3,000	**5.6425**	16,927.41	3,000	**5.2500**	15,750.00	-1,177.41	-6.96	-1.15
	Regulatory Assets (kW)	3,000	0.2600	780.00	3,000	0.3100	930.00	150.00		0.15
	Sub-Total			**17,736.35**			**16,706.92**	**-1,029.43**	**-5.80**	**-1.00**
	Other Charges (kWh)	1,037,649	0.0132	13,696.96	1,037,649	0.0132	13,696.96	0.00	0.00	0.00
	Other Charges (kW)	3,113	4.0000	12,451.78	3,113	3.9100	12,171.62	-280.17	-2.25	-0.27
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	1,037,649	0.0580	60,183.61	1,037,649	0.0580	60,183.61	0.00	0.00	0.00
	Total Bill			**104,068.70**			**102,759.11**	**-1,309.59**	**-1.26**	**-1.27**

Street Lighting

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			**0.29**			**0.27**	-0.02	-7.19	-0.14
150 kWh	Distribution (kWh)	150	**0.0000**	0.00	150	**0.0000**	0.00	0.00		0.00
1 kW	Distribution (kW)	1	**4.0763**	2.04	1	**3.7800**	1.89	-0.15	-7.27	-0.97
	Regulatory Assets (kW)	1	0.0300	0.02	1	0.0800	0.04	0.03		0.16
	Sub-Total			**2.34**			**2.20**	**-0.14**	**-6.15**	**-0.94**
	Other Charges (kWh)	156	0.0132	2.05	156	0.0132	2.05	0.00	0.00	0.00
	Other Charges (kW)	1	4.8900	2.54	1	4.7800	2.48	-0.06	-2.25	-0.37
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	156	0.0550	8.56	156	0.0550	8.56	0.00	0.00	0.00
	Total Bill			**15.50**			**15.29**	**-0.20**	**-1.30**	**-1.31**

9-1 BILL IMPACTS *(Monthly Consumptions)*

Street Lighting

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**0.29**			**0.27**	-0.02	-7.19	-7.75
0 kWh	Distribution (kWh)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
0 kW	Distribution (kW)	0	**4.0763**	0.00	0	**3.7800**	0.00	0.00		0.00
	Regulatory Assets (kW)	0	0.0300	0.00	0	0.0800	0.00	0.00		0.00
	Sub-Total			**0.29**			**0.27**	**-0.02**	**-7.19**	**-7.75**
	Other Charges (kWh)	0	0.0132	0.00	0	0.0132	0.00	0.00		0.00
	Other Charges (kW)	0	4.8900	0.00	0	4.7800	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Total Bill			**0.29**			**0.27**	**-0.02**	**-7.19**	**-7.75**

Street Lighting

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**0.29**			**0.27**	-0.02	-7.19	-7.75
0 kWh	Distribution (kWh)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
0 kW	Distribution (kW)	0	**4.0763**	0.00	0	**3.7800**	0.00	0.00		0.00
	Regulatory Assets (kW)	0	0.0300	0.00	0	0.0800	0.00	0.00		0.00
	Sub-Total			**0.29**			**0.27**	**-0.02**	**-7.19**	**-7.75**
	Other Charges (kWh)	0	0.0132	0.00	0	0.0132	0.00	0.00	#DIV/0!	0.00
	Other Charges (kW)	0	4.8900	0.00	0	4.7800	0.00	0.00	#DIV/0!	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00	#DIV/0!	0.00
	Total Bill			**0.29**			**0.27**	**-0.02**	**-7.19**	**-7.75**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-2 BILL IMPACTS %

	Volume		Change %			Volume		Change %			Volume		Change %		
	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*
RESIDENTIAL															
Regular	100		*(5.2)*	*(5.0)*	*(3.6)*	250		*(2.7)*	*(2.6)*	*(1.4)*	500		*0.2*	*(0.2)*	*(0.1)*
Time of Use	100			*(1.9)*	*(0.3)*	250			*(1.9)*	*(0.3)*	500			*(1.9)*	*(0.3)*
GENERAL SERVICE															
Less than 50 kW	1,000		*(3.0)*	*(2.8)*	*(1.2)*	2,000		*(1.7)*	*(1.7)*	*(0.6)*	5,000		*(0.4)*	*(0.8)*	*(0.3)*
50 to 1000 kW - Non Interval	15,000	60	*(1.9)*	*(2.0)*	*(0.7)*	40,000	100	*(1.7)*	*(1.9)*	*(0.5)*	100,000	500	*(1.5)*	*(1.8)*	*(0.7)*
50 to 1000 kW - Interval	15,000	60	*(5.6)*	*(4.3)*	*(1.6)*	40,000	100	*(5.6)*	*(4.2)*	*(1.1)*	100,000	500	*(5.5)*	*(4.1)*	*(1.7)*
Intermediate Use (1000 - 5000 kW)	800,000	3,000	*(4.6)*	*(3.4)*	*(1.1)*	1,000,000	3,000	*(4.6)*	*(3.4)*	*(1.0)*	1,200,000	4,000	*(4.6)*	*(3.4)*	*(1.0)*
Large Use (> 5000 kW) Includes Standby Charges	2,800,000	6,000	*(3.8)*	*(2.9)*	*(0.6)*	10,000,000	15,000	*(3.7)*	*(2.9)*	*(0.5)*	1,200,000		*(5.5)*	*(5.5)*	*(0.2)*
Unmetered Scattered Load - Admin per Customer			*(7.6)*	*(7.6)*	*(7.6)*			*(7.6)*	*(7.6)*	*(7.6)*			*(7.6)*	*(7.6)*	*(7.6)*
Unmetered Scattered Load - Charge per Connection	150	1	*5.8*	*5.8*	*0.2*	200	1	*5.8*	*5.8*	*0.1*			*5.8*	*5.8*	*5.8*
Street Lighting	150	1	*(5.5)*	*(3.9)*	*(1.2)*			*(7.2)*	*(7.2)*	*(7.2)*			*(7.2)*	*(7.2)*	*(7.2)*
Back-up/Standby Power															

9-2 BILL IMPACTS %

	Volume		Change %		
	kWh	kW	Distributn	Delivery	Total Bill
RESIDENTIAL					
Regular	750		2.2	1.2	0.5
Time of Use	750			(1.9)	(0.3)
GENERAL SERVICE					
Less than 50 kW	10,000		0.2	(0.5)	(0.1)
50 to 1000 kW - Non Interval	400,000	1,000	(1.5)	(1.8)	(0.4)
50 to 1000 kW - Interval	400,000	1,000	(5.5)	(4.1)	(1.1)
Intermediate Use (1000 - 5000 kW)	1,800,000	4,000	(4.6)	(3.4)	(0.8)
Large Use (> 5000 kW) Includes Standby Charges			(5.5)	(5.5)	(5.5)
Unmetered Scattered Load - Admin per Customer			(7.6)	(7.6)	(7.6)
Unmetered Scattered Load - Charge per Connection			5.8	5.8	5.8
Street Lighting			(7.2)	(7.2)	(7.2)
Back-up/Standby Power					

9-2 BILL IMPACTS %

	Volume		Change %			Volume		Change %			Volume		Change %		
	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*
RESIDENTIAL															
Regular	1,000		*3.6*	*2.2*	*0.9*	1,500		*5.5*	*3.4*	*1.2*	2,000		*6.8*	*4.1*	*1.4*
Time of Use	1,000			*(1.9)*	*(0.3)*	1,500			*(1.9)*	*(0.3)*	2,000			*(1.9)*	*(0.3)*
GENERAL SERVICE															
Less than 50 kW	15,000		*0.4*	*(0.3)*	*(0.1)*			*(7.5)*	*(7.5)*	*(7.5)*			*(7.5)*	*(7.5)*	*(7.5)*
50 to 1000 kW - Non Interval	1,000,000	3,000	*(1.5)*	*(1.8)*	*(0.5)*			*(7.0)*	*(7.0)*	*(7.0)*			*(7.0)*	*(7.0)*	*(7.0)*
50 to 1000 kW - Interval	1,000,000	3,000	*(5.5)*	*(4.1)*	*(1.2)*			*(7.0)*	*(7.0)*	*(7.0)*			*(7.0)*	*(7.0)*	*(7.0)*
Intermediate Use (1000 - 5000 kW)			*(6.1)*	*(6.1)*	*(6.1)*			*(6.1)*	*(6.1)*	*(6.1)*			*(6.1)*	*(6.1)*	*(6.1)*
Large Use (> 5000 kW) Includes Standby Charges			*(5.5)*	*(5.5)*	*(5.5)*			*(5.5)*	*(5.5)*	*(5.5)*			*(5.5)*	*(5.5)*	*(5.5)*
Unmetered Scattered Load - Admin per Customer			*(7.6)*	*(7.6)*	*(7.6)*			*(7.6)*	*(7.6)*	*(7.6)*			*(7.6)*	*(7.6)*	*(7.6)*
Unmetered Scattered Load - Charge per Connection			*5.8*	*5.8*	*5.8*			*5.8*	*5.8*	*5.8*			*5.8*	*5.8*	*5.8*
Street Lighting			*(7.2)*	*(7.2)*	*(7.2)*			*(7.2)*	*(7.2)*	*(7.2)*			*(7.2)*	*(7.2)*	*(7.2)*
Back-up/Standby Power															

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-1ALT BILL IMPACTS *(Monthly Consumptions)*

constant RTSR and Cost of Power Commodity

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			13.64			12.62	-1.02	-7.45	-4.63
100 kWh	Distribution (kWh)	100	0.0173	1.73	100	0.0162	1.62	-0.11	-6.14	-0.48
0 kW	Distribution (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
	Regulatory Assets (kWh)	100	0.0028	0.28	100	0.0032	0.32	0.04		0.18
	Sub-Total			15.65			14.57	-1.08	-6.91	-4.93
	Other Charges (kWh)	100	0.0236	2.36	100	0.0236	2.36	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	100	0.0500	5.00	100	0.0500	5.00	0.00	0.00	0.00
	Total Bill			23.01			21.93	-1.08	-4.70	-4.93

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			13.64			12.62	-1.02	-7.45	-2.83
250 kWh	Distribution (kWh)	250	0.0173	4.32	250	0.0162	4.06	-0.27	-6.14	-0.74
	Regulatory Assets (kWh)	250	0.0028	0.70	250	0.0032	0.80	0.10		0.28
	Sub-Total			18.66			17.48	-1.18	-6.33	-3.29
	Other Charges (kWh)	250	0.0236	5.90	250	0.0236	5.90	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	250	0.0500	12.50	250	0.0500	12.50	0.00	0.00	0.00
	Total Bill			37.06			35.88	-1.18	-3.19	-3.29

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			13.64			12.62	-1.02	-7.45	-1.72
500 kWh	Distribution (kWh)	500	0.0173	8.64	500	0.0162	8.11	-0.53	-6.14	-0.90
0 kW	Distribution (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
	Regulatory Assets (kWh)	500	0.0028	1.40	500	0.0032	1.60	0.20		0.34
	Sub-Total			23.68			22.34	-1.35	-5.68	-2.28
	Other Charges (kWh)	500	0.0236	11.80	500	0.0236	11.80	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	500	0.0500	25.00	500	0.0500	25.00	0.00	0.00	0.00
	Total Bill			60.48			59.14	-1.35	-2.23	-2.28

9-1ALT BILL IMPACTS *(Monthly Consumptions)*

constant RTSR and Cost of Power Commodity

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-1.23
750 kWh	Distribution (kWh)	750	**0.0173**	12.97	750	**0.0162**	12.17	-0.80	-6.14	-0.97
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	750	0.0028	2.10	750	0.0032	2.40	0.30		0.36
	Sub-Total			**28.71**			**27.19**	**-1.51**	**-5.27**	**-1.83**
	Other Charges (kWh)	750	0.0236	17.70	750	0.0236	17.70	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	750	0.0500	37.50	750	0.0500	37.50	0.00	0.00	0.00
	Total Bill			**83.91**			**82.39**	**-1.51**	**-1.80**	**-1.83**

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-0.96
1,000 kWh	Distribution (kWh)	1,000	**0.0173**	17.29	1,000	**0.0162**	16.23	-1.06	-6.14	-1.00
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	1,000	0.0028	2.80	1,000	0.0032	3.20	0.40		0.38
	Sub-Total			**33.73**			**32.05**	**-1.68**	**-4.97**	**-1.59**
	Other Charges (kWh)	1,000	0.0236	23.60	1,000	0.0236	23.60	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Total Bill			**107.33**			**105.65**	**-1.68**	**-1.56**	**-1.59**

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-0.65
1,500 kWh	Distribution (kWh)	1,500	**0.0173**	25.93	1,500	**0.0162**	24.34	-1.59	-6.14	-1.02
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	1,500	0.0028	4.20	1,500	0.0032	4.80	0.60		0.38
	Sub-Total			**43.77**			**41.76**	**-2.01**	**-4.59**	**-1.29**
	Other Charges (kWh)	1,500	0.0236	35.40	1,500	0.0236	35.40	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	500	0.0580	29.00	500	0.0580	29.00	0.00	0.00	0.00
	Total Bill			**158.17**			**156.16**	**-2.01**	**-1.27**	**-1.29**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-1ALT BILL IMPACTS ***(Monthly Consumptions)***

constant RTSR and Cost of Power Commodity

RESIDENTIAL Regular

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**13.64**			**12.62**	-1.02	-7.45	-0.49
2,000 kWh	Distribution (kWh)	2,000	**0.0173**	34.58	2,000	**0.0162**	32.46	-2.12	-6.14	-1.03
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	2,000	0.0028	5.60	2,000	0.0032	6.40	0.80		0.39
	Sub-Total			**53.82**			**51.48**	**-2.34**	**-4.34**	**-1.13**
	Other Charges (kWh)	2,000	0.0236	47.20	2,000	0.0236	47.20	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	1,000	0.0580	58.00	1,000	0.0580	58.00	0.00	0.00	0.00
	Total Bill			**209.02**			**206.68**	**-2.34**	**-1.12**	**-1.13**

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-1.22
1,000 kWh	Distribution (kWh)	1,000	**0.0207**	20.72	1,000	**0.0194**	19.40	-1.32	-6.36	-1.18
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	1,000	0.0012	1.20	1,000	0.0015	1.50	0.30		0.27
	Sub-Total			**40.19**			**37.81**	**-2.38**	**-5.93**	**-2.14**
	Other Charges (kWh)	1,000	0.0237	23.70	1,000	0.0237	23.70	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Total Bill			**113.89**			**111.51**	**-2.38**	**-2.09**	**-2.14**

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.64
2,000 kWh	Distribution (kWh)	2,000	**0.0207**	41.44	2,000	**0.0194**	38.80	-2.64	-6.36	-1.23
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	2,000	0.0012	2.40	2,000	0.0015	3.00	0.60		0.28
	Sub-Total			**62.11**			**58.71**	**-3.40**	**-5.48**	**-1.59**
	Other Charges (kWh)	2,000	0.0237	47.40	2,000	0.0237	47.40	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	1,000	0.0580	58.00	1,000	0.0580	58.00	0.00	0.00	0.00
	Total Bill			**217.51**			**214.11**	**-3.40**	**-1.56**	**-1.59**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-1ALT BILL IMPACTS ***(Monthly Consumptions)***

constant RTSR and Cost of Power Commodity

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.26
5,000 kWh	Distribution (kWh)	5,000	**0.0207**	103.59	5,000	**0.0194**	97.00	-6.59	-6.36	-1.26
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	5,000	0.0012	6.00	5,000	0.0015	7.50	1.50		0.29
	Sub-Total			**127.87**			**121.41**	**-6.46**	**-5.05**	**-1.24**
	Other Charges (kWh)	5,000	0.0237	118.50	5,000	0.0237	118.50	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	4,000	0.0580	232.00	4,000	0.0580	232.00	0.00	0.00	0.00
	Total Bill			**528.37**			**521.91**	**-6.46**	**-1.22**	**-1.24**

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.13
10,000 kWh	Distribution (kWh)	10,000	**0.0207**	207.19	10,000	**0.0194**	194.00	-13.19	-6.36	-1.27
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	10,000	0.0012	12.00	10,000	0.0015	15.00	3.00		0.29
	Sub-Total			**237.46**			**225.91**	**-11.55**	**-4.86**	**-1.12**
	Other Charges (kWh)	10,000	0.0237	237.00	10,000	0.0237	237.00	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	9,000	0.0580	522.00	9,000	0.0580	522.00	0.00	0.00	0.00
	Total Bill			**1,046.46**			**1,034.91**	**-11.55**	**-1.10**	**-1.12**

GENERAL SERVICE Less than 50 kW

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**18.27**			**16.91**	-1.36	-7.46	-0.09
15,000 kWh	Distribution (kWh)	15,000	**0.0207**	310.78	15,000	**0.0194**	291.00	-19.78	-6.36	-1.28
0 kW	Distribution (kW)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
	Regulatory Assets (kWh)	15,000	0.0012	18.00	15,000	0.0015	22.50	4.50		0.29
	Sub-Total			**347.05**			**330.41**	**-16.64**	**-4.80**	**-1.08**
	Other Charges (kWh)	15,000	0.0237	355.50	15,000	0.0237	355.50	0.00	0.00	0.00
	Other Charges (kW)	0	0.0000	0.00	0	0.0000	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	1,000	0.0500	50.00	1,000	0.0500	50.00	0.00	0.00	0.00
	Cost of Power Commodity (kW)	14,000	0.0580	812.00	14,000	0.0580	812.00	0.00	0.00	0.00
	Total Bill			**1,564.55**			**1,547.91**	**-16.64**	**-1.06**	**-1.08**

9-1ALT BILL IMPACTS *(Monthly Consumptions)*

constant RTSR and Cost of Power Commodity

GENERAL SERVICE 50 to 1000 kW - Non Interval

Consumption		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
15,000 kWh	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.12
60 kW	Distribution (kWh)	15,000	**0.0000**	0.00	15,000	**0.0000**	0.00	0.00		0.00
	Distribution (kW)	60	**5.6425**	338.55	60	**5.2500**	315.00	-23.55	-6.96	-1.41
	Regulatory Assets (kW)	60	0.2600	15.60	60	0.3100	18.60	3.00		0.18
	Sub-Total			**383.08**			**360.52**	**-22.56**	**-5.89**	**-1.35**
	Other Charges (kWh)	15,000	0.0132	198.00	15,000	0.0132	198.00	0.00	0.00	0.00
	Other Charges (kW)	60	4.0000	240.00	60	4.0000	240.00	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	15,000	0.0580	870.00	15,000	0.0580	870.00	0.00	0.00	0.00
	Total Bill			**1,691.08**			**1,668.52**	**-22.56**	**-1.33**	**-1.35**

GENERAL SERVICE 50 to 1000 kW - Non Interval

Consumption		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
40,000 kWh	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.05
100 kW	Distribution (kWh)	40,000	**0.0000**	0.00	40,000	**0.0000**	0.00	0.00		0.00
	Distribution (kW)	100	**5.6425**	564.25	100	**5.2500**	525.00	-39.25	-6.96	-1.02
	Regulatory Assets (kW)	100	0.2600	26.00	100	0.3100	31.00	5.00		0.13
	Sub-Total			**619.18**			**582.92**	**-36.26**	**-5.86**	**-0.95**
	Other Charges (kWh)	40,000	0.0132	528.00	40,000	0.0132	528.00	0.00	0.00	0.00
	Other Charges (kW)	100	4.0000	400.00	100	4.0000	400.00	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	40,000	0.0580	2,320.00	40,000	0.0580	2,320.00	0.00	0.00	0.00
	Total Bill			**3,867.18**			**3,830.92**	**-36.26**	**-0.94**	**-0.95**

GENERAL SERVICE 50 to 1000 kW - Non Interval

Consumption		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
100,000 kWh	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.02
500 kW	Distribution (kWh)	100,000	**0.0000**	0.00	100,000	**0.0000**	0.00	0.00		0.00
	Distribution (kW)	500	**5.6425**	2,821.24	500	**5.2500**	2,625.00	-196.24	-6.96	-1.65
	Regulatory Assets (kW)	500	0.2600	130.00	500	0.3100	155.00	25.00		0.21
	Sub-Total			**2,980.17**			**2,806.92**	**-173.25**	**-5.81**	**-1.45**
	Other Charges (kWh)	100,000	0.0132	1,320.00	100,000	0.0132	1,320.00	0.00	0.00	0.00
	Other Charges (kW)	500	4.0000	2,000.00	500	4.0000	2,000.00	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	100,000	0.0580	5,800.00	100,000	0.0580	5,800.00	0.00	0.00	0.00
	Total Bill			**12,100.17**			**11,926.92**	**-173.25**	**-1.43**	**-1.45**

9-1ALT BILL IMPACTS *(Monthly Consumptions)*

constant RTSR and Cost of Power Commodity

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	-0.01
400,000 kWh	Distribution (kWh)	400,000	**0.0000**	0.00	400,000	**0.0000**	0.00	0.00		0.00
1,000 kW	Distribution (kW)	1,000	**5.6425**	5,642.47	1,000	**5.2500**	5,250.00	-392.47	-6.96	-1.03
	Regulatory Assets (kW)	1,000	0.2600	260.00	1,000	0.3100	310.00	50.00		0.13
	Sub-Total			**5,931.40**			**5,586.92**	**-344.49**	**-5.81**	**-0.90**
	Other Charges (kWh)	400,000	0.0132	5,280.00	400,000	0.0132	5,280.00	0.00	0.00	0.00
	Other Charges (kW)	1,000	4.0000	4,000.00	1,000	4.0000	4,000.00	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	400,000	0.0580	23,200.00	400,000	0.0580	23,200.00	0.00	0.00	0.00
	Total Bill			**38,411.40**			**38,066.92**	**-344.49**	**-0.90**	**-0.90**

GENERAL SERVICE 50 to 1000 kW - Non Interval

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			**28.93**			**26.92**	-2.02	-6.97	0.00
1,000,000 kWh	Distribution (kWh)	1,000,000	**0.0000**	0.00	1,000,000	**0.0000**	0.00	0.00		0.00
3,000 kW	Distribution (kW)	3,000	**5.6425**	16,927.41	3,000	**5.2500**	15,750.00	-1,177.41	-6.96	-1.18
	Regulatory Assets (kW)	3,000	0.2600	780.00	3,000	0.3100	930.00	150.00		0.15
	Sub-Total			**17,736.35**			**16,706.92**	**-1,029.43**	**-5.80**	**-1.03**
	Other Charges (kWh)	1,000,000	0.0132	13,200.00	1,000,000	0.0132	13,200.00	0.00	0.00	0.00
	Other Charges (kW)	3,000	4.0000	12,000.00	3,000	4.0000	12,000.00	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	1,000,000	0.0580	58,000.00	1,000,000	0.0580	58,000.00	0.00	0.00	0.00
	Total Bill			**100,936.35**			**99,906.92**	**-1,029.43**	**-1.02**	**-1.03**

Street Lighting

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			**0.29**			**0.27**	-0.02	-7.19	-0.14
150 kWh	Distribution (kWh)	150	**0.0000**	0.00	150	**0.0000**	0.00	0.00		0.00
1 kW	Distribution (kW)	1	**4.0763**	2.04	1	**3.7800**	1.89	-0.15	-7.27	-1.00
	Regulatory Assets (kW)	1	0.0300	0.02	1	0.0800	0.04	0.03		0.17
	Sub-Total			**2.34**			**2.20**	**-0.14**	**-6.15**	**-0.97**
	Other Charges (kWh)	150	0.0132	1.98	150	0.0132	1.98	0.00	0.00	0.00
	Other Charges (kW)	1	4.8900	2.45	1	4.8900	2.45	0.00	0.00	0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	150	0.0550	8.25	150	0.0550	8.25	0.00	0.00	0.00
	Total Bill			**15.02**			**14.87**	**-0.14**	**-0.96**	**-0.97**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-1ALT BILL IMPACTS *(Monthly Consumptions)*

constant RTSR and Cost of Power Commodity

Street Lighting

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			0.29			0.27	-0.02	-7.19	-7.75
	Regulatory Assets (kW)	0	0.0300	0.00	0	0.0800	0.00	0.00		0.00
	Sub-Total			0.29			0.27	-0.02	-7.19	-7.75
	Other Charges (kWh)	0	0.0132	0.00	0	0.0132	0.00	0.00		0.00
	Other Charges (kW)	0	4.8900	0.00	0	4.8900	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Cost of Power Commodity (kW)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Total Bill			**0.29**			**0.27**	**-0.02**	**-7.19**	**-7.75**

Street Lighting

		2005 BILL			2006 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			0.29			0.27	-0.02	-7.19	-7.75
0 kWh	Distribution (kWh)	0	**0.0000**	0.00	0	**0.0000**	0.00	0.00		0.00
0 kW	Distribution (kW)	0	**4.0763**	0.00	0	**3.7800**	0.00	0.00		0.00
	Regulatory Assets (kW)	0	0.0300	0.00	0	0.0800	0.00	0.00		0.00
	Sub-Total			0.29			0.27	-0.02	-7.19	-7.75
	Other Charges (kWh)	0	0.0132	0.00	0	0.0132	0.00	0.00		0.00
	Other Charges (kW)	0	4.8900	0.00	0	4.8900	0.00	0.00		0.00
	Cost of Power Commodity (kWh)	0	0.0550	0.00	0	0.0550	0.00	0.00		0.00
	Total Bill			**0.29**			**0.27**	**-0.02**	**-7.19**	**-7.75**

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-2ALT BILL IMPACTS %

constant RTSR and Cost of Power Commodity

	Volume		Change %			Volume		Change %			Volume		Change %		
	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*
RESIDENTIAL															
Regular	100		(5.2)	(5.0)	(3.5)	250		(2.7)	(2.6)	(1.3)	500		0.2	(0.2)	0.1
Time of Use	100			(1.9)		250			(1.9)		500			(1.9)	
GENERAL SERVICE															
Less than 50 kW	1,000		(3.0)	(2.8)	(1.0)	2,000		(1.7)	(1.7)	(0.5)	5,000		(0.4)	(0.8)	(0.1)
50 to 1000 kW - Non Interval	15,000	60	(1.9)	(2.0)	(0.4)	40,000	100	(1.7)	(1.9)	(0.3)	100,000	500	(1.5)	(1.8)	(0.4)
50 to 1000 kW - Interval	15,000	60	(5.6)	(4.3)	(1.3)	40,000	100	(5.6)	(4.2)	(0.9)	100,000	500	(5.5)	(4.1)	(1.3)
Intermediate Use (1000 - 5000 kW)	800,000	3,000	(4.6)	(3.4)	(0.8)	1,000,000	3,000	(4.6)	(3.4)	(0.7)	1,200,000	4,000	(4.6)	(3.4)	(0.8)
Large Use (> 5000 kW) Includes Standby Charges	2,800,000	6,000	(3.8)	(2.9)	(0.4)	10,000,000	15,000	(3.7)	(2.9)	(0.3)	1,200,000		(5.5)	(5.5)	(0.2)
Unmetered Scattered Load - Admin per Customer			(7.6)	(7.6)	(7.6)			(7.6)	(7.6)	(7.6)			(7.6)	(7.6)	(7.6)
Unmetered Scattered Load - Charge per Connection	150	1	5.8	5.8	0.2	200	1	5.8	5.8	0.2			5.8	5.8	5.8
Street Lighting	150	1	(5.5)	(3.9)	(0.9)			(7.2)	(7.2)	(7.2)			(7.2)	(7.2)	(7.2)
Back-up/Standby Power					#DIV/0!										

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric Syster

ED-2002-0497 (EB-2005-0020)

August 2 2005

9-2ALT BILL IMPACTS %

constant RTSR and Cost of Power Commodity

	Volume		Change %		
	kWh	kW	*Distributn*	*Delivery*	*Total Bill*
RESIDENTIAL					
Regular	750		*2.2*	*1.3*	*0.7*
Time of Use	750			*(1.9)*	
GENERAL SERVICE					
Less than 50 kW	10,000		*0.2*	*(0.5)*	*0.0*
50 to 1000 kW - Non Interval	400,000	1,000	*(1.5)*	*(1.8)*	*(0.2)*
50 to 1000 kW - Interval	400,000	1,000	*(5.5)*	*(4.1)*	*(0.8)*
Intermediate Use (1000 - 5000 kW)	1,800,000	4,000	*(4.6)*	*(3.4)*	*(0.6)*
Large Use (> 5000 kW) Includes Standby Charges			*(5.5)*	*(5.5)*	*(5.5)*
Unmetered Scattered Load - Admin per Customer			*(7.6)*	*(7.6)*	*(7.6)*
Unmetered Scattered Load - Charge per Connection			*5.8*	*5.8*	*5.8*
Street Lighting			*(7.2)*	*(7.2)*	*(7.2)*
Back-up/Standby Power					

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Toronto Hydro-Electric Syster

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August 2 2005

9-2ALT BILL IMPACTS %

constant RTSR and Cost of Power Commodity

	Volume		Change %			Volume		Change %			Volume		Change %		
	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*	kWh	kW	*Distributn*	*Delivery*	*Total Bill*
RESIDENTIAL															
Regular	1,000		*3.6*	*2.2*	*1.1*	1,500		*5.5*	*3.4*	*1.4*	2,000		*6.8*	*4.1*	*1.6*
Time of Use	1,000			*(1.9)*		1,500			*(1.9)*		2,000			*(1.9)*	
GENERAL SERVICE															
Less than 50 kW	15,000		*0.4*	*(0.3)*	*0.1*			*(7.5)*	*(7.5)*	*(7.5)*			*(7.5)*	*(7.5)*	*(7.5)*
50 to 1000 kW - Non Interval	1,000,000	3,000	*(1.5)*	*(1.8)*	*(0.2)*			*(7.0)*	*(7.0)*	*(7.0)*			*(7.0)*	*(7.0)*	*(7.0)*
50 to 1000 kW - Interval	1,000,000	3,000	*(5.5)*	*(4.1)*	*(1.0)*			*(7.0)*	*(7.0)*	*(7.0)*			*(7.0)*	*(7.0)*	*(7.0)*
Intermediate Use (1000 - 5000 kW)			*(6.1)*	*(6.1)*	*(6.1)*			*(6.1)*	*(6.1)*	*(6.1)*			*(6.1)*	*(6.1)*	*(6.1)*
Large Use (> 5000 kW) Includes Standby Charges			*(5.5)*	*(5.5)*	*(5.5)*			*(5.5)*	*(5.5)*	*(5.5)*			*(5.5)*	*(5.5)*	*(5.5)*
Unmetered Scattered Load - Admin per Customer			*(7.6)*	*(7.6)*	*(7.6)*			*(7.6)*	*(7.6)*	*(7.6)*			*(7.6)*	*(7.6)*	*(7.6)*
Unmetered Scattered Load - Charge per Connection			*5.8*	*5.8*	*5.8*			*5.8*	*5.8*	*5.8*			*5.8*	*5.8*	*5.8*
Street Lighting			*(7.2)*	*(7.2)*	*(7.2)*			*(7.2)*	*(7.2)*	*(7.2)*			*(7.2)*	*(7.2)*	*(7.2)*
Back-up/Standby Power															

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-1 RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges
Effective May 1, 2006

Customer Class	Item Description	Unit	Rate $
RESIDENTIAL Regular			
	Monthly Service Charge	per customer/30 days	12.62
	Distribution Volumetric Rate	per kWh	0.0162
	Regulatory Assets	per kWh	0.0032
RESIDENTIAL Time of Use			
GENERAL SERVICE Less than 50 kW			
	Monthly Service Charge	per customer/30 days	16.91
	Distribution Volumetric Rate	per kWh	0.0194
	Regulatory Assets	per kWh	0.0015
GENERAL SERVICE 50 to 1000 kW - Non Interval			
	Monthly Service Charge	per customer/30 days	26.92
	Distribution Volumetric Rate	per kVA/30 days	5.2500
	Regulatory Assets	per kVA/30 days	0.3100
GENERAL SERVICE 50 to 1000 kW - Interval			
	Monthly Service Charge	per customer/30 days	27.17
	Distribution Volumetric Rate	per kVA/30 days	5.2300
	Regulatory Assets	per kVA/30 days	0.0900
GENERAL SERVICE Intermediate Use (1000 - 5000 kW)			
	Monthly Service Charge	per customer/30 days	754.81
	Distribution Volumetric Rate	per kVA/30 days	4.3800
	Regulatory Assets	per kVA/30 days	0.0700
GENERAL SERVICE Large Use (> 5000 kW) Includes Standby Charges			
	Monthly Service Charge	per customer/30 days	2,902.06
	Distribution Volumetric Rate	per kVA/30 days	3.7400
	Regulatory Assets	per kVA/30 days	0.0700
GENERAL SERVICE Unmetered Scattered Load - Admin per Customer			
	Monthly Service Charge	per customer/30 days	2.09
	Distribution Volumetric Rate	per kWh	0.0189

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-1 RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges
Effective May 1, 2006

Customer Class	Item Description	Unit	Rate $
	Regulatory Assets	per kWh	0.0014
Unmetered Scattered Load - Charge per Connection			
	Monthly Service Charge	per customer/30 days	0.31
Street Lighting			
	Monthly Service Charge	per customer/30 days	0.27
	Distribution Volumetric Rate	per kVA/30 days	3.7800
	Regulatory Assets	per kVA/30 days	0.0800
Back-up/Standby Power			

10-2 RATES SCHEDULE (Part 2)

Schedule of Distribution Rates and Charges

Effective May 1, 2006

Item Description (Rate Code)	Calculation Basis	Rate $
Duplicate invoices for previous billing (4)	Standard	15.00
Easement letter (6)	Standard	15.00
Income tax letter (7)	Standard	15.00
Returned cheque charge (plus bank charges) (11)	Standard	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable) (14)	Standard	30.00
Special meter reads (15)	Standard	30.00
Collection of account charge - no disconnection (16)	Standard	30.00
Disconnect/Reconnect at meter - during regular hours (18)	Standard	65.00
Install/Remove load control device - during regular hours (19)	Standard	65.00
Disconnect/Reconnect at meter - after regular hours (20)	Standard	185.00
Install/Remove load control device - after regular hours (21)	Standard	185.00

10-2 RATES SCHEDULE (Part 2)

Schedule of Distribution Rates and Charges
Effective May 1, 2006

Item Description (Rate Code)	Calculation Basis	Rate $
Disconnect/Reconnect at pole - during regular hours (22)	Standard	185.00
Disconnect/Reconnect at pole - after regular hours (23)	Standard	415.00
Meter dispute charge plus Measurement Canada fees (if meter found correct) (24)	Standard	30.00
Specific Charge for Access to the Power Poles $/pole/year (30)	Standard	22.35
Specific Charge for Access to the Power Poles $/pole/year (Third Party Attachements on Hydro Poles) (31)	*addnl. chrge*	18.55
Specific Charge for Access to the Power Poles $/pole/year (Hydro Attachements on Third Party	*addnl. chrge*	-22.75
Standby Monthly Backup Admin Charges (33)	*addnl. chrge*	200.00

Loss Factors

Supply Facilities Loss Factor	1.0045
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0330
Distribution Loss Factor - Secondary Metered Customer > 5,000 kW	1.0141
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0227
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0040
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0376
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0187
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0273
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0085

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Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

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10-3 RATES SCHEDULE (Part 3)

Schedule of Distribution Rates and Charges
Effective May 1, 2006

Customer Class	Unit	Connection Rate $
RESIDENTIAL Regular	per kWh	0.0045
RESIDENTIAL Time of Use	per kWh	0.0045
GENERAL SERVICE Less than 50 kW	per kWh	0.0045
GENERAL SERVICE 50 to 1000 kW - Non Interval	per kVA/30 days	1.6800
GENERAL SERVICE 50 to 1000 kW - Interval	per kVA/30 days	1.7100
GENERAL SERVICE Intermediate Use (1000 - 5000 kW)	per kVA/30 days	1.7700
GENERAL SERVICE Large Use (> 5000 kW) Includes Standby Charges	per kVA/30 days	1.8000
GENERAL SERVICE Unmetered Scattered Load - Admin per Customer	per kWh	0.0045
Unmetered Scattered Load - Charge per Connection		
Street Lighting	per kVA/30 days	2.0300
Back-up/Standby Power	per kVA/30 days	

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-4 DISTR. RATES - RECONCILED

	Volumes from 7-1			Rates from 8-5			Calculated Revenue		Allocations		
	Number of Customers (Connections)	3 yr average kWh per customer	3 yr average kW per customer	Rate per kWh ($)	Rate per kW ($)	Fixed Service Charge ($)	**Full Precision $**	**Pro-forma Billing Rates $**	Base Revenue Requirement - B.R.R. #1 (from 7-1) $	LV Wheeling Requirment - B.R.R. #2 (from 7-2) $	CDM Requirement - B.R.R. #3 (from 7-3) $
RESIDENTIAL											
Regular	597,210	9,161	0	0.0162	0.0000	12.62	**179,242,748**	**179,071,141**	180,476,304	22,849	0
Regular	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Regular	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Regular	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Urban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Urban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Urban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Urban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Suburban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Suburban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Suburban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Suburban	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0

10-4 DISTR. RATES - RECONCILED

	Volumes from 7-1			Rates from 8-5			Calculated Revenue		Allocations		
	Number of Customers (Connections)	3 yr average kWh per customer	3 yr average kW per customer	Rate per kWh ($)	Rate per kW ($)	Fixed Service Charge ($)	**Full Precision $**	**Pro-forma Billing Rates $**	Base Revenue Requirement - B.R.R. #1 (from 7-1) $	LV Wheeling Requirment - B.R.R. #2 (from 7-2) $	CDM Requirement - B.R.R. #3 (from 7-3) $
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
GENERAL SERVICE											
Less than 50 kW	66,505	39,405	0	0.0194	0.0000	16.91	**64,335,723**	**64,335,019**	64,624,715	10,945	0
Less than 50 kW	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Less than 50 kW	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Less than 50 kW	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Less than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Less than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Less than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Less than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other < 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other < 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other < 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other < 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
50 to 1000 kW - Non Interval	9,550	646,571	1,817	0.0000	5.2500	26.92	**94,178,461**	**94,178,848**	95,473,414	27,290	0
Greater than 50 kW (to 3000 kW)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Greater than 50 kW (to 3000 kW)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Greater than 50 kW (to 3000 kW)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
50 to 1000 kW - Interval	1,682	2,180,420	5,037	0.0000	5.2300	27.17	**44,858,121**	**44,858,096**	45,501,929	13,551	0
Greater than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Greater than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Greater than 50 kW Time of Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0

10-4 DISTR. RATES - RECONCILED

	Volumes from 7-1			Rates from 8-5			Calculated Revenue		Allocations		
	Number of Customers (Connections)	3 yr average kWh per customer	3 yr average kW per customer	Rate per kWh ($)	Rate per kW ($)	Fixed Service Charge ($)	**Full Precision $**	**Pro-forma Billing Rates $**	Base Revenue Requirement - B.R.R. #1 (from 7-1) $	LV Wheeling Requirment - B.R.R. #2 (from 7-2) $	CDM Requirement - B.R.R. #3 (from 7-3) $
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other > 50 kW (specify) .	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Intermediate Use (1000 - 5000 kW)	511	9,941,640	23,142	0.0000	4.3800	754.81	**56,423,766**	**56,423,766**	57,172,131	19,545	0
Intermediate Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Intermediate Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Intermediate Use	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Large Use (> 5000 kW) Includes Standby Charges	47	55,428,161	118,436	0.0000	3.7400	2,902.06	**22,455,421**	**22,455,421**	22,743,838	9,349	0
Large Use (> 5000 kW)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Large Use (> 5000 kW)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Large Use (> 5000 kW)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Unmetered Scattered Load - Admin per Customer	1,438	37,823	0	0.0189	0.0000	2.09	**1,064,131**	**1,064,168**	1,062,395	227	0
Unmetered Scattered Load	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Unmetered Scattered Load	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Unmetered Scattered Load	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Unmetered Scattered Load - Charge per Connection	13,408	0	0	0.0000	0.0000	0.31	**49,384**	**49,876**	50,070	0	0
Sentinel Lighting	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Sentinel Lighting	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Sentinel Lighting	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Street Lighting	159,861	682	2	0.0000	3.7800	0.27	**1,716,720**	**1,718,199**	1,741,547	604	0

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric System Limited

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-4 DISTR. RATES - RECONCILED

	Volumes from 7-1			Rates from 8-5			Calculated Revenue		Allocations		
	Number of Customers (Connections)	3 yr average kWh per customer	3 yr average kW per customer	Rate per kWh ($)	Rate per kW ($)	Fixed Service Charge ($)	**Full Precision $**	**Pro-forma Billing Rates $**	Base Revenue Requirement - B.R.R. #1 (from 7-1) $	LV Wheeling Requirment - B.R.R. #2 (from 7-2) $	CDM Requirement - B.R.R. #3 (from 7-3) $
Street Lighting	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Street Lighting	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Street Lighting	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Back-up/Standby Power	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Back-up/Standby Power	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Back-up/Standby Power	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Back-up/Standby Power	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Other (specify)	0	0	0	0.0000	0.0000	0.00	**0**	**0**	0	0	0
Transformer Allowance (from 6-3)							***-12,154,588***	***-12,154,588***	-12,154,588		
TOTALS	850,212						**452,169,887**	**451,999,949**	456,691,756	104,360	0

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric Syste

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-4 DISTR. RATES - RECONCILED

	Revenue Requirement including CDM & LV/Wheeling $	Difference	
		Full Precision $	Pro-forma Billing $
RESIDENTIAL			
Regular	180,499,154	1,256,406	1,428,012
Regular	0	0	0
Regular	0	0	0
Regular	0	0	0
Time of Use	0	0	0
Time of Use	0	0	0
Time of Use	0	0	0
Time of Use	0	0	0
Urban	0	0	0
Urban	0	0	0
Urban	0	0	0
Urban	0	0	0
Suburban	0	0	0
Suburban	0	0	0
Suburban	0	0	0
Suburban	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric Syste

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-4 DISTR. RATES - RECONCILED

	Revenue Requirement including CDM & LV/Wheeling $	Difference	
		Full Precision $	Pro-forma Billing $
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
GENERAL SERVICE			
Less than 50 kW	64,635,660	299,937	300,641
Less than 50 kW	0	0	0
Less than 50 kW	0	0	0
Less than 50 kW	0	0	0
Less than 50 kW Time of Use	0	0	0
Less than 50 kW Time of Use	0	0	0
Less than 50 kW Time of Use	0	0	0
Less than 50 kW Time of Use	0	0	0
Other < 50 kW (specify) .	0	0	0
Other < 50 kW (specify) .	0	0	0
Other < 50 kW (specify) .	0	0	0
Other < 50 kW (specify) .	0	0	0
50 to 1000 kW - Non Interval	95,500,704	1,322,244	1,321,856
Greater than 50 kW (to 3000 kW)	0	0	0
Greater than 50 kW (to 3000 kW)	0	0	0
Greater than 50 kW (to 3000 kW)	0	0	0
50 to 1000 kW - Interval	45,515,480	657,359	657,384
Greater than 50 kW Time of Use	0	0	0
Greater than 50 kW Time of Use	0	0	0
Greater than 50 kW Time of Use	0	0	0

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric Syste

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-4 DISTR. RATES - RECONCILED

	Revenue Requirement including CDM & LV/Wheeling $	Difference	
		Full Precision $	Pro-forma Billing $
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Other > 50 kW (specify) .	0	0	0
Intermediate Use (1000 - 5000 kW)	57,191,676	767,910	767,910
Intermediate Use	0	0	0
Intermediate Use	0	0	0
Intermediate Use	0	0	0
Large Use (> 5000 kW) Includes Standby Charges	22,753,187	297,766	297,766
Large Use (> 5000 kW)	0	0	0
Large Use (> 5000 kW)	0	0	0
Large Use (> 5000 kW)	0	0	0
Unmetered Scattered Load - Admin per Customer	1,062,622	-1,510	-1,547
Unmetered Scattered Load	0	0	0
Unmetered Scattered Load	0	0	0
Unmetered Scattered Load	0	0	0
Unmetered Scattered Load - Charge per Connection	50,070	686	194
Sentinel Lighting	0	0	0
Sentinel Lighting	0	0	0
Sentinel Lighting	0	0	0
Street Lighting	1,742,151	25,430	23,952

EDR 2006 MODEL (ver. 2)

Toronto Hydro-Electric Syste

ED-2002-0497 (EB-2005-0020)

August 2 2005

10-4 DISTR. RATES - RECONCILED

	Revenue Requirement including CDM & LV/Wheeling $	Difference	
		Full Precision $	Pro-forma Billing $
Street Lighting	0	0	0
Street Lighting	0	0	0
Street Lighting	0	0	0
Back-up/Standby Power	0	0	0
Back-up/Standby Power	0	0	0
Back-up/Standby Power	0	0	0
Back-up/Standby Power	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Other (specify)	0	0	0
Transformer Allowance (from 6-3)	*-12,154,588*		
TOTALS	456,796,116	4,626,229	4,796,168

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-2005-0020**
	EB-2005-0421
Name of Contact:	
Phone Number:	**Ext:**
E-Mail Address:	
Date:	
Version Number:	**PILS2006.V2.0**

SUMMARY SHEET

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

Ratebase	1,884,817,378	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	59,371,747	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)	6.70%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	82,111,495		

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 2004 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	No
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2004 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 2004 and/or prior years?	No

Tax Rates & Exemptions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

Applicant	Rate Base	OCT Exemption	LCT Exemption
		10,000,000	50,000,000
Toronto Hydro-Electric System Limited	1,884,817,378	10,000,000	50,000,000
Regulated Affiliates (if applicable)			
1.		0	0
2.		0	0
3.		0	0
4.		0	0
5.		0	0
Total	1,884,817,378	10,000,000	50,000,000

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	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	0.300%
LCT rate	0.125%
Surtax	1.12%

2004 Adjusted Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

	A	B	C	D	E
9		**T2S1 line #**	**Total for Legal Entity**	**Non-Distribution Eliminations**	**2004 Wires Only**
10	**Income before PILs/Taxes**	**A**	103,960,000	0	103,960,000
11	**Additions:**				
12	Interest and penalties on taxes	103	29,316	0	29,316
13	Amortization of tangible assets	104	122,525,811	0	122,525,811
14	Amortization of intangible assets	106	0	0	0
15	Recapture of capital cost allowance from Schedule 8	107	0	0	0
16	Gain on sale of eligible capital property from Schedule 10	108	0	0	0
17	Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
18	Loss in equity of subsidiaries and affiliates	110	0	0	0
19	Loss on disposal of assets	111	0	0	0
20	Charitable donations	112	0	0	0
21	Taxable Capital Gains	113	457,456	0	457,456
22	Political Donations	114	0	0	0
23	Deferred and prepaid expenses	116	0	0	0
24	Scientific research expenditures deducted on financial statements	118	0	0	0
25	Capitalized interest	119	0	0	0
26	Non-deductible club dues and fees	120	59,818	0	59,818
27	Non-deductible meals and entertainment expense	121	52,191	0	52,191
28	Non-deductible automobile expenses	122	0	0	0
29	Non-deductible life insurance premiums	123	0	0	0
30	Non-deductible company pension plans	124	0	0	0
31	Tax reserves deducted in prior year	125	0	0	0
32	Reserves from financial statements- balance at end of year	126	118,186,990	0	118,186,990
33	Soft costs on construction and renovation of buildings	127	0	0	0
34	Book loss on joint ventures or partnerships	205	0	0	0
35	Capital items expensed	206	0	0	0
36	Debt issue expense	208	0	0	0
37	Development expenses claimed in current year	212	0	0	0
38	Financing fees deducted in books	216	0	0	0
39	Gain on settlement of debt	220	0	0	0
40	Non-deductible advertising	226	0	0	0
41	Non-deductible interest	227	0	0	0
42	Non-deductible legal and accounting fees	228	0	0	0
43	Recapture of SR&ED expenditures	231	538,238	0	538,238
44	Share issue expense	235	0	0	0
45	Write down of capital property	236	0	0	0
46	Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
47	***Other Additions***				0
48	Interest Expensed on Capital Leases	290	0	0	0
49	Realized Income from Deferred Credit Accounts	291	0	0	0
50	Pensions	292	0	0	0
51	Non-deductible penalties	293	0	0	0
52	Debt Financing Expenses for Book Purposes	294	731,936	0	731,936
53	See Attached	295	28,754,343	0	28,754,343
54	**Total Additions**		**271,336,099**	**0**	**271,336,099**

2004 Adjusted Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

	A	B	C	D	E
9		T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
55					
56	**Deductions:**				
57	Gain on disposal of assets per financial statements	401	1,043,000	0	1,043,000
58	Dividends not taxable under section 83	402	0	0	0
59	Capital cost allowance from Schedule 8	403	119,294,094	0	119,294,094
60	Terminal loss from Schedule 8	404	0	0	0
61	Cumulative eligible capital deduction from Schedule 10	405	1,316,077	0	1,316,077
62	Allowable business investment loss	406	0	0	0
63	Deferred and prepaid expenses	409	0	0	0
64	Scientific research expenses claimed in year	411	0	0	0
65	Tax reserves claimed in current year	413	0	0	0
66	Reserves from financial statements - balance at beginning of year	414	118,727,291	0	118,727,291
67	Contributions to deferred income plans	416	0	0	0
68	Book income of joint venture or partnership	305	0	0	0
69	Equity in income from subsidiary or affiliates	306	0	0	0
70	*Other deductions: (Please explain in detail the nature of the item)*				
71					
72	Interest capitalized for accounting deducted for tax	390	0	0	0
73	Capital Lease Payments	391	0	0	0
74	Non-taxable imputed interest income on deferral and variance accounts	392	2,233,344	0	2,233,344
75	Financing Fees for Tax Under S.20(1)(e)	393	1,027,325	0	1,027,325
76	See Attached	394	30,625,831	0	30,625,831
77	**Total Deductions**		**274,266,962**	**0**	**274,266,962**
78					
79	**Net Income for Tax Purposes**		**101,029,137**	**0**	**101,029,137**
80					
81					
82	Charitable donations from Schedule 2	311	0	0	0
83	Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
84	Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
85	Net-capital losses of preceding taxation years from Schedule 4	332	3,494	0	3,494
86	Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
87					
88	**TAXABLE INCOME**		**101,025,643**	**0**	**101,025,643**

Attachment to 2004 Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-2005-0020, EB-2005-0421

Other Additions

	Amount
ARO Accretion Expenses	235,261
Capital Contributions Under S.12(1)(k)	28,519,082
	28,754,343

Attachment to 2004 Adjusted Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-2005-0020, EB-2005-0421

Other Deductions

	Amount
Financing Fees for Tax Under S.20(1)(e.1)	243,600
Capital Tax Adjust to Actual	(123,434)
ARO Payments - Deductible for Tax	140,308
S.13(7.4) Election	28,519,082
Bad Debt Recovery - Pre. October 1, 2001	1,308,037
ITC Booked in Accounting Income	538,238
	30,625,831

2005 Schedule 8 and 10 UCC and CEC

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

Methodology: This schedule starts with 2004 Schedules 8 and 10, as filed in the actual 2004 corporate tax returns; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the 2005 Schedules.

Class	Class Description	UCC End of Year Dec 31/04 per tax returns	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC 2005 Opening Balance
1	Distribution System - post 1987	1,433,889,894	0	0	1,433,889,894
2	Distribution System - pre 1988	540,520,861	0	0	540,520,861
8	General Office/Stores Equip	45,493,778	0	0	45,493,778
10	Computer Hardware/ Vehicles	17,756,599	0	0	17,756,599
10.1	Certain Automobiles	0	0	0	0
12	Computer Software	1,980,215	0	0	1,980,215
13_1	Lease # 1	109,089	0	0	109,089
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	6,422,594	0	0	6,422,594
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	1,160,129	0	0	1,160,129
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
98	0	17,264,966	0	0	17,264,966
0	0	0	0	0	0
	SUB-TOTAL - UCC	**2,064,598,125**	**0**	**0**	**2,064,598,125**
CEC	Goodwill	17,485,029	0	0	17,485,029
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	0	0	0	
0	0	0	0	0	
0	0	0	0	0	
	SUB-TOTAL - CEC	**17,485,029**	**0**	**0**	**17,485,029**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:

Total Capital Assets for PILs Model		CCA Class	2005 Projected Capital Transactions		2005 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	2,539,833	0	2,539,833	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
1715	Station Equipment	1	4,037,942	0	4,037,942	0
1720	Towers and Fixtures	1	0	0	0	0
1725	Poles and Fixtures	1	0	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0	0
1735	Underground Conduit	1	0	0	0	0
1740	Underground Conductors and Devices	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0	0
1825	Storage Battery Equipment	1	0	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0	0
1840	Underground Conduit	1	0	0	0	0
1845	Underground Conductors and Devices	1	0	0	0	0
1850	Line Transformers	1	113,712,722	0	113,712,722	0
1855	Services	1	0	0	0	0
1860	Meters	1		0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0	0
1908	Buildings and Fixtures	1	0	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0	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
xxx1	Fixed Assets for Conservation and Demand Management	1	1,751,103	0	1,751,103	0
xxx2	Smart Meters	1	0	0	0	0
SUBTOTAL - CLASS 1			**122,041,601**	**0**	**122,041,601**	**0**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:

Total Capital Assets for PILs Model		CCA Class	2005 Projected Capital Transactions		2005 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
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
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**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:

Total Capital Assets for PILs Model		CCA Class	2005 Projected Capital Transactions		2005 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	74,367	0	74,367	0
1935	Stores Equipment	8	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0
1955	Communication Equipment	8	21,273	0	21,273	0
1960	Miscellaneous Equipment	8	3,306,467	0	3,306,467	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		0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0
	SUBTOTAL - CLASS 8		**3,402,106**	**0**	**3,402,106**	**0**
1920	Computer Equipment - Hardware	45	1,256,824	0	1,256,824	0
	SUBTOTAL - CLASS 45		**1,256,824**	**0**	**1,256,824**	**0**
1930	Transportation Equipment	10	3,238,446	0	3,238,446	0
	SUBTOTAL - CLASS 10		**3,238,446**	**0**	**3,238,446**	**0**
1925	Computer Software - CL12	12	7,460,319	0	7,460,319	0
	SUBTOTAL - CLASS 12		**7,460,319**	**0**	**7,460,319**	**0**
1630	Leasehold Improvements	13_1	0	0	0	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		**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**
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	109,009	0	109,009	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		**109,009**	**0**	**109,009**	**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		**137,508,304**	**0**	**137,508,304**	**0**

2005 Schedule 8 CCA

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC 2005 Opening Balance	2005 Projected Additions	2005 Projected Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2005 CCA	UCC End of 2005
1	Distribution System - post 1987	1,433,889,894	122,041,601	0	1,555,931,495	61,020,800	1,494,910,694	4%	59,796,428	1,496,135,067
2	Distribution System - pre 1988	540,520,861	0	0	540,520,861	0	540,520,861	6%	32,431,252	508,089,609
8	General Office/Stores Equip	45,493,778	3,402,106	0	48,895,884	1,701,053	47,194,831	20%	9,438,966	39,456,918
10	Computer Hardware/ Vehicles	17,756,599	3,238,446	0	20,995,045	1,619,223	19,375,822	30%	5,812,747	15,182,298
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	1,980,215	7,460,319	0	9,440,534	3,730,160	5,710,375	100%	5,710,375	3,730,160
13_1	Leasehold Improvement # 1	109,089	0	0	109,089	0	109,089		43,240	65,849
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	N/A	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	6,422,594	0	0	6,422,594	0	6,422,594	8%	513,808	5,908,786
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	1,160,129	1,256,824	0	2,416,953	628,412	1,788,541	45%	804,844	1,612,110
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
98	0	17,264,966	0	0	17,264,966	0	17,264,966		0	17,264,966
0	0	0	0	0	0	0	0		0	0
		0	0	0					0	0
		0	0	0					0	0
	TOTAL	**2,064,598,125**	**137,399,296**	**0**	**2,201,997,421**	**68,699,648**	**2,133,297,773**		**114,551,658**	**2,087,445,763**

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

Cumulative Eligible Capital				17,485,029
Additions				
Cost of Eligible Capital Property Acquired during 2005	109,009			
Other Adjustments	0			
Subtotal	109,009	**x 3/4 =**	81,756	
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	
			81,756	**81,756**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**17,566,785**
Deductions				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during 2005	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	**0**
Cumulative Eligible Capital Balance				**17,566,785**
Taxation Year 2005 Deduction		**17,566,785**	**x 7% =**	**1,229,675**
Cumulative Eligible Capital - 2005 Closing Balance				**16,337,110**

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-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

Methodology: This schedule starts with projected 2005 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 31/05 Per 2005 Sch. 8 & 10	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System - post 1987	1,496,135,067	0	0	1,496,135,067
2	Distribution System - pre 1988	508,089,609	0	0	508,089,609
8	General Office/Stores Equip	39,456,918	0	0	39,456,918
10	Computer Hardware/ Vehicles	15,182,298	0	0	15,182,298
10.1	Certain Automobiles	0	0	0	0
12	Computer Software	3,730,160	0	0	3,730,160
13_1	Lease # 1	65,849	0	0	65,849
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	5,908,786	0	0	5,908,786
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	1,612,110	0	0	1,612,110
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
98	0	17,264,966	0	0	17,264,966
0	0	0	0	0	0
	SUB-TOTAL - UCC	**2,087,445,763**	**0**	**0**	**2,087,445,763**
CEC	Goodwill	16,337,110	0	0	16,337,110
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	0	0	0	
0	0	0	0	0	
0	0	0	0	0	
	SUB-TOTAL - CEC	**16,337,110**	**0**	**0**	**16,337,110**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:

Total Capital Assets for PILs Model		CCA Class	2006 Projected Capital Transactions		2006 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	1,640,755	0	1,640,755	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
1715	Station Equipment	1	6,892,042	0	6,892,042	0
1720	Towers and Fixtures	1	0	0	0	0
1725	Poles and Fixtures	1	0	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0	0
1735	Underground Conduit	1	0	0	0	0
1740	Underground Conductors and Devices	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0	0
1825	Storage Battery Equipment	1	0	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0	0
1840	Underground Conduit	1	0	0	0	0
1845	Underground Conductors and Devices	1	0	0	0	0
1850	Line Transformers	1	94,079,625	0	94,079,625	0
1855	Services	1	0	0	0	0
1860	Meters	1		0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0	0
1908	Buildings and Fixtures	1	0	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0	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
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0	0
xxx2	Smart Meters	1	48,677,000	0	48,677,000	0
SUBTOTAL - CLASS 1			**151,289,422**	**0**	**151,289,422**	**0**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:

Total Capital Assets for PILs Model		CCA Class	2006 Projected Capital Transactions		2006 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
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
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**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:

Total Capital Assets for PILs Model		CCA Class	2006 Projected Capital Transactions		2006 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	310,500	0	310,500	0
1935	Stores Equipment	8	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0
1955	Communication Equipment	8	562,500	0	562,500	0
1960	Miscellaneous Equipment	8	1,212,329	0	1,212,329	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	2,025,201	0	2,025,201	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0
	SUBTOTAL - CLASS 8		**4,110,530**	**0**	**4,110,530**	**0**
1920	Computer Equipment - Hardware	45	1,789,850	0	1,789,850	0
	SUBTOTAL - CLASS 45		**1,789,850**	**0**	**1,789,850**	**0**
1930	Transportation Equipment	10	4,224,250	0	4,224,250	0
	SUBTOTAL - CLASS 10		**4,224,250**	**0**	**4,224,250**	**0**
1925	Computer Software - CL12	12	17,642,182	0	17,642,182	0
	SUBTOTAL - CLASS 12		**17,642,182**	**0**	**17,642,182**	**0**
1630	Leasehold Improvements	13_1	0	0	0	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		**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**
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	34,496	0	34,496	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		**34,496**	**0**	**34,496**	**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		**179,090,730**	**0**	**179,090,730**	**0**

Schedule 8 CCA Test Year

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	2006 Projected Additions	2006 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 - post 1987	1,496,135,067	151,289,422	0	1,647,424,489	75,644,711	1,571,779,778	4%	62,871,191	1,584,553,298
2	Distribution System - pre 1988	508,089,609	0	0	508,089,609	0	508,089,609	6%	30,485,377	477,604,233
8	General Office/Stores Equip	39,456,918	4,110,530	0	43,567,448	2,055,265	41,512,183	20%	8,302,437	35,265,011
10	Computer Hardware/ Vehicles	15,182,298	4,224,250	0	19,406,548	2,112,125	17,294,423	30%	5,188,327	14,218,221
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	3,730,160	17,642,182	0	21,372,341	8,821,091	12,551,251	100%	12,551,251	8,821,091
13_1	Leasehold Improvement # 1	65,849	0	0	65,849	0	65,849		43,240	22,609
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	N/A	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	5,908,786	0	0	5,908,786	0	5,908,786	8%	472,703	5,436,084
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	1,612,110	1,789,850	0	3,401,960	894,925	2,507,035	45%	1,128,166	2,273,794
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
98	0	17,264,966	0	0	17,264,966	0	17,264,966		0	17,264,966
0	0	0	0	0	0	0	0		0	0
		0							0	0
		0							0	0
	TOTAL	2,087,445,763	179,056,233	0	2,266,501,996	89,528,117	2,176,973,880		121,042,690	2,145,459,306

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility:
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact: Phone Number:

Cumulative Eligible Capital				**16,337,110**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	34,496			
Other Adjustments	0			
Subtotal	34,496	**x 3/4 =**	25,872	
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	
			25,872	**25,872**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**16,362,983**
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				**16,362,983**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**16,362,983**	**x 7% =**	**1,145,409**
Cumulative Eligible Capital - Closing Balance				**15,217,574**

Schedule 13 – Tax Reserves

Name of Utility:
License Number: ED-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact: Phone Number:

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2005	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2005 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2005 Adjusted Utility Balance (C/F Tab "2004 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-2002-0497
File Numbers: RP-2005-0020 / EB-2005-0421
Name of Contact: Phone Number:

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2005	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2005 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2005 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments Add (+)	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)			0		0			0	0	
General reserve for bad debts			0		0			0	0	
Accrued Employee Future Benefits:	113,267,000		113,267,000		113,267,000	5,128,000		118,395,000	5,128,000	
- 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	
- 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	
			0		0			0	0	
			0		0			0	0	
Total	**113,267,000**	**0**	**113,267,000**	**0**	**113,267,000**	**5,128,000**	**0**	**118,395,000**	**5,128,000**	**0**

Schedule 7-1 Loss Carry-Forwards

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

Corporation Loss Continuity and Application

Sign Convention:
Increase (+) Decrease (-)

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion [1]	Utility Balance
Actual/Estimated December 31, 2004	Not applicable		0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	**#VALUE!**	**0**	**0**

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion [1]	Utility Balance
Actual/Estimated December 31, 2004	not applicable		0
Application of Loss Carry Forward to reduce taxable capital gains in 2005			0
Other Adjustments +ADD -(DEDUCT)			0
Balance available for use in Test Year	**#VALUE!**	**0**	**0**

Note

[1] **Please describe your methodology and rationale in the Manager's Summary**

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

Calculated Deemed 2004 Interest Expense in 2006 EDR model	82,111,495	
2004 Actual Interest Expense	81,607,659	2-2 UNADJUSTED ACCOUNTING DATA L 491
2004 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA L 431
2004 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA L 432
2004 Actual Interest	81,607,659	
Interest Forecast for Tier 1 or 2 Adjustments		
Total Interest	81,607,659	
Excess Interest Expense for 2006 PILs	0	

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2004 and prior years.

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		59,371,747	103,960,000	-44,588,253	
Additions:					
Interest and penalties on taxes	103		29,316	-29,316	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	128,513,000	122,525,811	5,987,189	Capital additions projected for 2005 and 2006
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	0	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		457,456	-457,456	no capital gains projected for 2006
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		59,818	-59,818	
Non-deductible meals and entertainment expense	121		52,191	-52,191	
Non-deductible automobile expenses	122		0	0	
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	118,395,000	118,186,990	208,010	
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	
Recapture of SR&ED expenditures	231		538,238	-538,238	This was an in and out adjustment as already reflected in accounting income
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	
Realized Income from Deferred Credit Accounts	291		0	0	
Pensions	292		0	0	
Non-deductible penalties	293		0	0	
Debt Financing Expenses for Book Purpose	294	298,872	731,936	-433,064	See Test Year Financing Fees schdeule
See Attached	295		28,754,343	-28,754,343	This is substantially all contributions for capital additions which has an equal deduction below. See "2004 Taxable Income Additions" tab.
	296		0	0	
	297		0	0	
Total Additions		**247,206,872**	**271,336,099**	**-24,129,227**	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Deductions:					
Gain on disposal of assets per financial statements	401		1,043,000	-1,043,000	No gain on dispositions expected in 2006
Dividends not taxable under section 83	402		0	0	
Capital cost allowance from Schedule 8	403	121,042,690	119,294,094	1,748,596	capital asset additions projected for 2005 and 2006
Terminal loss from Schedule 8	404		0	0	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,145,409	1,316,077	-170,668	
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	113,267,000	118,727,291	-5,460,291	based on 2006 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)					
Interest capitalized for accounting deducted for tax	390		0	0	
Capital Lease Payments	391		0	0	
Non-taxable imputed interest income on deferral and variance accounts	392		2,233,344	-2,233,344	no such imputed interest expected in 2006
Financing Fees for Tax Under S.20(1)(e)	393	1,027,325	1,027,325		
See Attached	394		30,625,831		This is substantially all contributions for capital additions which has an equal addition above. See "2004 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		**236,482,424**	**274,266,962**	**-37,784,538**	
NET INCOME FOR TAX PURPOSES		**70,096,195**	**101,029,137**	**-30,932,942**	
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 losses of preceding taxation years from Schedule 7-1	332	0	3,494	-3,494	
Limited partnership losses of preceding taxation years from Schedule 4	335		0	0	
TAXABLE INCOME (C/F to tab "Tax Provision)		**70,096,195**	**101,025,643**	**-30,929,448**	

Attachment to Test Year Taxable Income

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-2005-0020, EB-2005-0421

Financing Fees Continuity

TAX TREATMENT

	Original Cost	Year of Expenditure	ITA Reference	Amortization 2002	2003	2004	2005	2006	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
Total			**S. 20(1)(e)**	**134,250**	**1,027,325**	**1,027,325**	**1,027,325**	**1,027,325**	**893,075**
Total			**S. 20(1)(e.1)**	**-**	**-**	**243,600**	**-**	**-**	**-**

ACCOUNTING TREATMENT

	Original Cost	Year of Expenditure		Amortization 2002	2003	2004	2005	2006	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	298,872	298,872	298,872	1,897,783
LC and Standby Charge	664,551	2003		-	664,551	-	-	-	-
Total				**534,688**	**1,536,876**	**731,936**	**380,072**	**298,872**	**1,897,783**

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B
Enter the LCT amount from either Section A or B in tab "Tax Provision" cell D28

Section A

	Wires Only
ONTARIO CAPITAL TAX	
Rate Base	1,884,817,378
Less: Exemption	10,000,000
Deemed Taxable Capital	1,874,817,378
Rate in 2006	0.300%
Net Amount (Taxable Capital x Rate)	5,624,452
FEDERAL LCT	
Rate Base from	1,884,817,378
Less: Exemption	50,000,000
Deemed Taxable Capital	1,834,817,378
Rate in 2006	0.125%
Gross Amount (Taxable Capital x Rate)	2,293,522
Less: Federal Surtax	785,077
Net LCT	1,508,444
Grossed-up LCT	2,361,372

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX

PAID-UP CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Paid-up capital stock	527,817,000		527,817,000
Retained earnings (if deficit, use negative sign)	145,013,824		145,013,824
Capital and other surplus excluding			0
appraisal surplus	11,391,000		11,391,000
Loans and advances	1,230,042,000		1,230,042,000
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits			0
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions	118,395,000		118,395,000
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	2,032,658,824	0	2,032,658,824
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	57,823,045		57,823,045
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	1,974,835,778	0	1,974,835,778

ELIGIBLE INVESTMENTS

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Bonds, lien notes, interest coupons	50,000,000		50,000,000
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			0
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	50,000,000	0	50,000,000

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

TOTAL ASSETS	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	2,254,536,592		2,254,536,592
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	2,254,536,592	0	2,254,536,592
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	57,823,385		57,823,385
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	2,196,713,207	0	2,196,713,207
Investment Allowance	44,949,786	0	44,949,786
Taxable Capital			
Net paid-up capital	1,974,835,778	0	1,974,835,778
Investment Allowance	44,949,786	0	44,949,786
Taxable Capital	1,929,885,992	0	1,929,885,992
Capital Tax Calculation			
Deduction from taxable capital up to $10,000,000	10,000,000		10,000,000
Net Taxable Capital			1,919,885,992
Rate			0.3000%
Ontario Capital Tax (Deductible, not grossed-up)			5,759,658

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

LARGE CORPORATION TAX

CAPITAL	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
ADD:			
Reserves that have not been deducted in computing income for the year under Part I	118,395,000		118,395,000
Capital stock	527,817,000		527,817,000
Retained earnings	145,013,824		145,013,824
Contributed surplus	11,391,000		11,391,000
Any other surpluses			0
Deferred unrealized foreign exchange gains			0
All loans and advances to the corporation	1,230,042,000		1,230,042,000
All indebtedness- bonds, debentures, notes, mortgages, bankers acceptances, or similar obligations			0
Any dividends declared but not paid			0
All other indebtedness outstanding for more than 365 days			0
Subtotal	2,032,658,824	0	2,032,658,824
DEDUCT:			
Deferred tax debit balance			0
Any deficit deducted in computing shareholders' equity			0
Any patronage dividends 135(1) deducted in computing income under Part I included in amounts above			0
Deferred unrealized foreign exchange losses			0
			0
Subtotal	0	0	0
Capital for the year	2,032,658,824	0	2,032,658,824

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

INVESTMENT ALLOWANCE	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Shares in another corporation			0
Loan or advance to another corporation	50,000,000		50,000,000
Bond, debenture, note, mortgage, or			0
similar obligation of another corporation			0
Long term debt of financial institution			0
Dividend receivable from another corporation			0
Debts of corporate partnerships that were not exempt from tax under Part I.3			0
Interest in a partnership			0
Investment Allowance	50,000,000	0	50,000,000

TAXABLE CAPITAL			
Capital for the year	2,032,658,824	0	2,032,658,824
Deduct: Investment allowance	50,000,000	0	50,000,000
Taxable Capital for taxation year	1,982,658,824	0	1,982,658,824
Deduct: Capital Deduction upto $50,000,000	50,000,000		50,000,000
Taxable Capital	1,932,658,824	0	1,932,658,824
Rate			0.12500%
Gross Part I.3 Tax LCT			2,415,823.53
Federal Surtax Rate			1.1200%
Less: Federal Surtax = Taxable Income x Surtax Rate			785,077
Net Part I.3 Tax - LCT Payable ***(If surtax is greater than Gross LCT, then zero)***			1,630,746
Net Part I.3 Tax - LCT Payable grossed-up (1 - 0.3612)			2,552,827

Attachment to Test Year OCT, LCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-2005-0020, EB-2005-0421

Loans and Advances

Advances from Associated Companies	180,000,000
current prtion of LT liabilities	15,181,000
deposits	37,600,000
Notes Payable to Associated Companies	980,231,000
other LT	4,449,000
Inter co payable	12,581,000
Total	1,230,042,000

Attachment to Test Year OCT, LCT

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-2005-0020, EB-2005-0421

Amounts Deducted for Income Tax > of Amounts Booked

Difference @ 12/31/2004 Per Income Tax Return		74,732,343
ADD:	2005 CCA	114,551,658
	2005 CEC Amount	1,229,675
LESS:	2005 Amortization Expense	(127,094,183)
ADD:	2006 CCA	121,042,690
	2006 CEC Amount	1,145,409
LESS:	2006 Amortization Expense	(128,513,000)
S. 20(1)(e)		1,027,325
Accounting amort.of finance fees		(298,872)
		57,823,045

Test Year PILs/ Tax Provision

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

	Wires Only	2004 Actual	Variance	Explanation of Variance
Regulatory Taxable Income - From 'Test Year Taxable Income'	70,096,195			
Corporate Income Tax Rate	36.12%			
Total Income Taxes	25,318,746			
Investment Tax Credits	200,000	200,000	0	
Miscellaneous Tax Credits			0	
Total Tax Credits	200,000	200,000	0	
Corporate PILs/Income Tax Provision for Test Year	25,118,746			
Ontario Capital Tax	5,759,658			
LCT	1,630,746			

INCLUSION IN RATES

Income Tax (grossed-up)	39,321,768
Ontario Capital Tax (not grossed-up)	5,759,658
LCT (grossed-up)	2,552,827
Tax Provision for 2006 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	47,634,254

PILs VARIANCE

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact: Phone Number:

		Income Taxes	OCT	LCT	TOTAL
Actual PILs/Taxes Paid by the Utility [1]	**2002**	690,244	5,572,030	4,259,382	10,521,656
	2003	25,315,472	5,807,282	3,701,157	34,823,911
	2004	36,477,150	5,780,886	2,769,775	45,027,811
Test Year PILs/Taxes [2]	**2006**	39,321,768	5,759,658	2,552,827	47,634,254
Variance (2006 vs. 2004)		2,844,618	- 21,228	- 216,948	2,606,443
Percentage Variance between Actual 2004 and 2006 Proxy					5.47%

If Cell K18 exceeds 25%, a narrative description of this variance shall be included in the Manager's Summary

Comments:

[1] Actual Wires-Only PILs/ Taxes paid includes income taxes, Ontario Capital Tax and Large Corporation Tax.
These values are available from your annual filings - SIMPIL model TaxRec

[2] Test Year PILs/Taxes include the grossed-up amounts for income taxes and Large Corporation Tax, plus Ontario Capital Tax.

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
License Number: ED-2002-0497
File Numbers: RP-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

		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-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

		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-2005-0020, EB-2005-0421
Name of Contact:
Phone Number:

		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
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 Supplementary

Toronto Hydro Electric System Limited
License Number: ED-2002-0497
File Number: RP-2005-0020, EB-2005-0421

Class	Class Description	October 1, 2001 FMV Bump	Rate %	Remaining balance of Bump 2004	Remaining balance of Bump 2006
1	Buildings; Electrical generating or distributing equipment and plant (including structures) acquired after 1987	339,044,594	4%	287,966,360	265,389,797
2	Electrical generating or distributing equipment acquired before 1988	181,931,132	6%	142,042,542	125,508,790
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
10	Automotive equipment & vehicle; Computer hardware - computer hardware and system software	11,032,587	30%	2,648,924	1,297,973
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
CEC	Cumulative Eligible Capital	11,726,704	7%	8,772,184	7,587,062
Total		**550,560,031**		**461,077,994**	**413,258,256**