Niagara On-The-Lake HYDRO

AESTATEM VIREMUS

Filed August 7, 2008

2009 ELECTRICITY DISTRIBUTION RATE APPLICATION

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Niagara-on-the-Lake Hydro Inc.

August 7, 2008

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
26th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Niagara-on-the-Lake Hydro Inc. 2009 Rate Application
OEB Case EB-2008-0237

Dear Ms. Walli

Niagara-on-the-Lake Hydro Inc. is pleased to submit its 2009 Rate Application in compliance with the OEB filing requirements for transmission and distribution applications, as follows:

- Exhibit 1 – Administrative Documents (including appendices)
- Exhibit 2 – Rate Base
- Exhibit 3 – Operating Revenue
- Exhibit 4 – Operating Costs
- Exhibit 5 – Deferral and Variance Accounts
- Exhibit 6 – Cost of Capital and Rate of Return
- Exhibit 7 – Calculation of Revenue Deficiency or Surplus
- Exhibit 8 – Cost Allocation
- Exhibit 9 – Rate Design
- Exhibit 10 – Request for LRAM and SSM Adjustments

An electronic copy of our full application will be submitted through the OEB e-Filing Services and two hard copies of the application will be sent by courier.

We would be pleased to provide any further information or details that you may require for this application.

Yours truly

Jim Huntingdon, President
Encl.

8 HENEGAN ROAD, P.O. BOX 460 • VIRGIL, ONTARIO • L0S 1T0
PHONE: 905-468-4235 • FAX: 905-468-3861

NIAGARA-ON-THE-LAKE HYDRO INC.

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES EFFECTIVE MAY 1, 2009

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OVERVIEW OF THE APPLICATION:

This Schedule provides information under the following headings:

- Manager's Summary;
- Background on NOTL Hydro;
- Purpose and Need;
- Timing;
- Customer Impacts;
- Major issues; and
- Comments.

Manager's Summary:

The purpose of NOTL Hydro's application is to be able to implement distribution rates effective May 1, 2009 which, when applied to the projected numbers of customers and weather normalized energy demand, will ensure that sufficient annual revenue is obtained to cover projected operating costs, amortization, interest and taxes, and provide the authorized rate of return on an updated rate base. At current 2008 rates, there would be a revenue shortfall of $206,184.

At the same time, NOTL Hydro's proposed rates would move the revenue to cost ratio for each customer class further towards the OEB guidelines for these ratios, while maintaining the current fixed/variable revenue ratio. The sentinel light class is proposed to be eliminated.

Significant updates to NOTL Hydro's rate base result from the 100% inclusion of two transformer stations (one built and in service in 2003 and the other purchased and in service in 2005) that were only 50% included in the rate base in the 2006 rate application, and an addition to the normal capital program level for 2009 for the Chautauqua project, described in detail in the application.

The authorized rate of return reflects the OEB-prescribed return on equity, currently 8.57%, and a weighted debt rate of 6.61%, which includes NOTL Hydro debt on a non-demand promissory note to the shareholder at 7.25% combined with CIBC bank debt at 6.03% and 5.38% for loans for the two transformer stations mentioned above. The debt to equity ratio is moved to 56.67%/43.33% from the 2008 ratio of 53.33%/46.67%.

The projected operating costs reflect normal cost increases such as through inflation and union collective agreements. No staffing increases beyond current 2008 levels are proposed. One additional lineman was added in 2008 to provide training and ensure continuity in case of a potential early retirement of a lineman in 2011.

Additional components of the proposed rates are LRAM/SSM rate riders for revenue foregone in 2005, 2006 (LRAM and SSM) and 2007 (LRAM only), rate riders to dispose of two deferral and variance accounts and smart meter rate riders of $1 pending finalization of NOTL Hydro's smart meter program and costing. The proposed smart meter rate is equivalent to the amount approved by the Board for those 2008 cost of service rate Applicants that are in a similar situation to NOTL Hydro (for example, Lakefront Utilities Inc. and PUC Distribution Inc.).

Background on NOTL Hydro:

Niagara-on-the-Lake Hydro Inc. is licensed by the Ontario Energy Board to provide electricity distribution services to approximately 7800 customers within the municipal boundaries of the Town of Niagara-on-the-Lake. We are bordered on the south by Niagara Falls, the west by St. Catharines, the north by Lake Ontario and to the east by the Niagara River. Our 133 km^2 service territory is primarily rural with urban pockets consisting of Old Town Niagara, Virgil, St. Davids, Niagara-on-the-Green and Queenston. NOTL Hydro Inc. is wholly-owned by the Town of Niagara-on-the-Lake and currently employs 19 full-time and 2 part-time staff.

The original Niagara Hydro-Electric Commission (Old Town) has roots back to 1892, while the balance of our service territory was purchased from Ontario Hydro in 1983. Shortly after incorporation in 2000, the Board of Directors adopted a mission statement and related values that continue to provide our company's guiding principles.

Our mission statement:

Niagara-on-the-Lake Hydro Inc. is committed to delivering energy-related products and services to our customers while:

- Providing the highest standard of safety, service and reliability,
- Operating with integrity in all our dealings, and
- Building value for our shareholder, your town of Niagara-on-the-Lake.

Our values:

Our values reflect our mission and our desire to maintain the trust that the community has placed in us:

- <u>Providing the highest standard of safety, service and reliability.</u>
  - Target performance within the top 25% of all municipal electric utilities.
- <u>Operating with integrity in all our dealings.</u>
  - Open and honest communications with our staff, customers, associates and partners, and with other electric utilities, the media and Town Council.
  - Integrity in our financial statements.
- <u>Building value for our shareholder, the Town of Niagara-on-the-Lake.</u>

- Leaving everything we touch better than we found it:
  - Enhance the environment;
  - Develop positive relationships.
- Balance the need for both long and short term returns.
- Support the goals of our owner, the Town.
- Protect and enhance the value of our assets.
- Maintain a strong electric utility team.

Our pursuit to achieve the highest standard of safety was recently recognized by our safety association E&USA as we received the Gold 'Outcomes' level of achievement award. NOTL Hydro is also very active in promoting safety in our community. In 2007 and 2008, we organized a Community Safety Day event assisted by dozens of safety partners. The event promoted fire, electrical, boating, bicycle and internet safety etc. and was well attended by families from around the region. NOTL Hydro recently participated in promoting safety awareness in summer jobs to hundreds of students at the local high school in conjunction with the Our Youth at Work organization. We are also an active participant in the CEO Safety Charter and Association of Safety Professionals.

Shortly after incorporation in 2001 and faced with a transformation capacity shortage for our customers, NOTL Hydro Inc. began planning for a new transformer station. In June, 2003, we officially placed 42 mW of capacity on-line with the opening of our own station York TS. This new station, including property, was constructed for $2.8 million and continues to benefit customers through increased reliability and lower line losses while building value for our shareholder. NOTL Hydro proceeded to purchase the existing transformer station NOTL D.S. from Hydro One late in 2005. This twenty year old station continues to attract capital improvements primarily to the protection and control components. These refurbishments are expected to extend the life of this station and improve the overall reliability through installation of the latest technology.

NOTL Hydro Inc. annually reinvests approximately $1.3 million into capital program. Our broad operational direction continues to include replacement (conversion) of the older inefficient 4 kV legacy system with a new, low line loss 27.6 kV system. To date, we have decommissioned four of the original five 4 kV substations from service. Given the importance of preserving history and attracting tourists in our community, our Town has issued by-laws that require our company to bury our facilities in the designated historical urban areas of Old Town and the hamlet of Queenston. Similarly, the Niagara Parks Commission requires burial of our facilities on the Niagara Parkway. NOTL Hydro distribution system line losses have been reduced from over 8% in the 1990's to currently less than 5% which is testament to the fact that our capital line loss reduction programs are effective. There are a few anomalies in our routine capital spending slated for 2009 and 2010. For efficiency purposes, a large underground and conversion to 27.6 kV project in the Chautauqua area of Old Town will be largely completed in two years versus three, requiring an additional $600,000 in capital spending in 2009. The expanded 2009 plan will see NOTL Hydro follow behind the Town's water and sewer construction and benefit through shared costs such as joint restoration.

Plans are also underway with our regional LDC partners to install an AMI (Smart Meter) system as early as 2009 which will also require additional capital spending to meet Ministry requirements. For the present Application, until the plans are fully developed and negotiations with the vendor completed, a rate rider of $1 per customer is requested as outlined in **Exhibit 9, Tab 1, Schedule 1**.

Purpose and Need

NOTL Hydro's requested revenue requirement for 2009 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt as it transitions to a 60%/40% debt equity ratio by 2010. Through this rate application, NOTL Hydro seeks the recovery through rates of its proposed 2009 base revenue requirement in the amount of $4,829,518.

When its forecasted customers, energy and demand for 2009 are considered, NOTL Hydro estimates that its present rates will produce a deficiency in distribution revenue of $206,184 for the 2009 Test Year. Excluded from this estimate is the impact of energy costs.

Therefore, NOTL Hydro seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in:

- **Appendix A** (at end of Exhibit 1) and
- **Exhibit 9, Tab 1, Schedule 7**

to this Application.

The information presented in this Application is NOTL Hydro's forecasted results for its 2009 Test Year. With the rates presently in effect, NOTL Hydro estimates that its revenue for 2009 would not be sufficient to provide a reasonable return. NOTL Hydro is also presenting the historical actual information for fiscal 2006, OEB-Approved data for 2006, actual information for fiscal 2007 as well as a forecast for the fiscal 2008 Bridge Year.

Timing

The financial information supporting the Test Year for this Application will be NOTL Hydro's fiscal year ending December 31, 2009 (the "2009 Test Year"). However, this information will be used to set rates for the period May 1, 2009 to April 30, 2012 (as

NOTL Hydro understands OEB's current intentions regarding the rebasing cycle). The Test Year revenue requirement is that forecast by NOTL Hydro as needed to enable it to earn the maximum return permitted by the OEB for the 2009 Test Year. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's Decision must be effective for volumes consumed on and after May 1, 2009.

Customer Impact

In preparing this application, NOTL Hydro has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, NOTL Hydro notes that for the majority of its customers, the revenue to cost ratio of each rate class falls within the applicable threshold defined by the OEB in the OEB's November 28, 2007, Report on Application of Cost Allocation for Electricity Distributors. For all customer classes, adjustments have been made to bring the revenue to cost ratio nearer to 100%.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include distribution rates [monthly service charge and volumetric rates], regulatory asset rate riders to dispose of the balances in the Regulatory Deferral and Variance Accounts over a 3 -year period and LRAM/SSM rate riders over a 2 -year period, are set out in Table 1 below.

Table 1

AVERAGE TOTAL BILL IMPACT – PERCENT & DOLLAR

Average Customer Total Bill	% Impact	$ Impact
Residential	3.50%	$3.87
1,000 kWh		
General Service <50kW	6.27%	$14.32
2,000 kWh		
General Service >50kW	(1.42%)	-$661.06
500,000 kWh		
1,100 kW		
Street Lighting	42.57%	$1,286.82
435 connections		
27,600 kWh		
60 kW		

Major Issues

The issues to be reviewed in this case, as NOTL Hydro sees them, are discussed in **Exhibit 1, Tab 1 Schedule 7** (Draft Issues List).

Comments

NOTL Hydro also offers comments on the following matters:

- **Capital Structure**

  NOTL Hydro is requesting a change in its deemed capital structure. Specifically, NOTL Hydro is requesting a decrease in the deemed equity ratio from 46.67% to 43.33% consistent with the second year of the phase-in of the shift in NOTL Hydro's capital structure from 50% to 40% equity as outlined in the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report").

- **Return on Equity**

NOTL Hydro has assumed a return on equity of 8.57% consistent with the letter from the OEB dated March 7, 2008 regarding Cost of Capital Parameter Updates for 2008 Cost of Service Applications. NOTL Hydro understands that the OEB will update the return on equity rate in early 2009 for rates effective May 1, 2009.

- **Capital Expenditures**

NOTL Hydro continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase in demand comes both from expansion of the NOTL Hydro distribution system into currently un-serviced areas and distribution system upgrades needed in existing areas.

- **Operating and Maintenance Costs**

Operating and maintenance costs have been updated to reflect the impact of inflation, union collective agreements and expected changes in costs.

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 Niagara-on-the-Lake Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2009.

Title of Proceeding:	An application by Niagara-on-the-Lake Hydro Inc.. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2009.
Applicant's Name:	**NIAGARA-ON-THE-LAKE HYDRO INC.**
Applicant's Address for Service:	PO Box 460 8 Henegan Road Virgil ON L0S 1T0
	Attention: Jim Huntingdon, President
	Telephone: 905.468.4235 ext. 55 Fax: 905.468.3861 E-mail: jhuntingdon@notlhydro.com

APPLICATION

1. Introduction

(a) The Applicant is Niagara-on-the-Lake Hydro Inc. (referred to in this Application as the "Applicant" or "NOTL Hydro"). The Applicant is a corporation incorporated pursuant to the Ontario *Business Corporations Act* with its head office in the village of Virgil, which is in the Town of Niagara-on-the-Lake. The Applicant carries on the business of distributing electricity within the municipal boundaries of the Town of Niagara-on-the-Lake.

(b) The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the *Ontario Energy Board Act, 1998* for approval of its proposed distribution rates and other charges, effective May 1, 2009. A list of requested approvals is set out in **Exhibit 1, Tab 1, Schedule 6** below.

(c) Except where specifically identified in the Application, the Applicant followed Chapter 2 of the OEB's Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the "Filing Requirements") in order to prepare this application.

2. Proposed Distribution Rates and Other Charges

(a) The Schedule of Rates and Charges proposed in this Application is identified in **Appendix A** (at end of Exhibit 1) and in **Exhibit 9, Tab 1, Schedule 7**, and the material being filed in support of this Application sets out NOTL Hydro's approach to its distribution rates and charges.

3. Proposed Effective Date of Rate Order

(a) The Applicant requests that the OEB make its Rate Order effective May 1, 2009 in accordance with the Filing Requirements.

(b) In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2009, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges effective May 1, 2009, which may be subject to adjustment based on its final Decision and Order.

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

(a) The Applicant submits the proposed 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 Filing Requirements and reflect traditional rate making and cost of service principles;

(ii) the proposed adjusted rates are necessary to meet the Applicant’s Market Based Rate of Return (“MBRR”) and Payments in Lieu of Taxes (“PILs”) requirements;

(iii) 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 the Applicant or the implementation of any other mitigation measures;

(iv) the other service charges proposed by the Applicant are the same as those previously approved by the OEB; and

(v) such other grounds as may be set out in the material accompanying this Application Summary.

5. Relief Sought

(a) The Applicant applies for an Order or Orders approving the proposed distribution rates and other charges set out in **<u>Appendix A</u>** to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2009, or as soon as possible thereafter; and

(b) In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2009, the Applicant requests that the OEB issue an interim Order approving the proposed distribution rates and other charges, effective May 1, 2009, which may be subject to adjustment based on its final Decision and Order.

6. Form of Hearing Requested

The Applicant recognizes that, as indicated in the OEB letter of May 27, 2008, the OEB is planning to include an oral component in all applications, either in the form of an oral hearing or in the case of written hearings, an oral technical conference. The Applicant requests that this Application be disposed of by written hearing with an oral technical conference if needed.

DATED at Virgil, Ontario, this 7th day of August, 2008.

All of which is respectfully submitted,

Jim Huntingdon
President
Niagara-on-the-Lake Hydro Inc.

Philip Wormwell
Director of Corporate Services
Niagara-on-the-Lake Hydro Inc.

NIAGARA-ON-THE-LAKE HYDRO INC.

DISTRIBUTOR LICENCE

Ontario

Electricity Distribution Licence
ED-2002-0547
Niagara-on-the-Lake Hydro Inc.

Valid Until
March 31, 2023

____
Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 16, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26e étage
Toronto ON M4P 1E4

Please refer to www.oebdocs.oeb.gov.on.ca/pdf/12MFR-0.pdf or to **APPENDIX B** (at end of Exhibit 1) for complete text version of licence.

NIAGARA-ON-THE-LAKE HYDRO INC.

CONTACT INFORMATION

Jim Huntingdon	Telephone:	905.468.4235 Ext. 55
President	Fax:	905.468.3861
	E-mail:	jhuntingdon@notlhydro.com

Philip Wormwell	Telephone:	905.468.4235 Ext. 38
Director of Corporate Services	Fax:	905.468.3861
	E-mail:	pwormwell@notlhydro.com

LIST OF SPECIFIC APPROVALS REQUESTED:

In this proceeding, NOTL Hydro is requesting the following approvals:

- Approval to charge rates effective May 1, 2009 to recover a revenue deficiency of $ 206,184 as set out in **Exhibit 7, Tab 1, Schedule 1**. The schedule of proposed rates is set out in **Appendix A** (at end of Schedule 1) and **Exhibit 9, Tab 1 Schedule 7**.

- Approval of the Applicant's proposed change in capital structure, decreasing the Applicant's deemed common equity component from 46.67%% to 43.33% and increasing the deemed debt component from 53.33% to 56.67%, as set out in **Exhibit 6, Tab 1, Schedule 2**, consistent with Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006;

- Approval of the proposed loss factor as set out in **Exhibit 4, Tab 2, Schedule 7**;

- Approval to continue the Specific Service Charges (other than Transformer Allowance) approved in the OEB's Rate Order in the matter of NOTL Hydro's 2008 distribution rates [EB-2007-0813],

- Approval to adjust the Transformer Allowance approved in the OEB's Rate Order in the matter of NOTL Hydro's 2008 distribution rates [EB-2007-0813] as set out in **Exhibit 9, Tab 1, Schedule 1**, and

- Approval to dispose of the following Deferral and Variance Account Balances as at April 30, 2009 over a 3 -year period using the method of recovery described in **Exhibit 5, Tab 1, Schedule 3**:

  1508 Other Regulatory Assets
  1550 Low Voltage

- Approval for revised Smart Meter rate riders as set out in **Exhibit 9, Tab 1, Schedule 1**, effective May 1, 2009.

- Approval for LRAM/SSM Rate riders as set out in **Exhibit 10, Tab 1, Schedule 2**, effective May 1, 2009 over a 2 -year period.

DRAFT ISSUES LIST:

NOTL Hydro would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2009 Test Year may constitute issues in this Application:

- The amount of NOTL Hydro's proposed revenue requirement
- The reasonableness of the proposed electricity distribution rates.
- The ability to continue providing our shareholder, the Town of Niagara-on-the-Lake with Note Payable interest at 7.25% and to recover the full amount through our rates.

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On March 12, 2007, the OEB issued a Report titled "LDC Screening Methodology to Establish a Rebasing Schedule for Electricity LDCs". The purpose of that Report was "to describe the criteria to be considered in determining which electricity distributors to engage in proceedings before the Board for rebasing to establish rates for each of the years 2009, 2009 and 2010" and to establish the next steps and timelines for filing. Section 3.3 of that Report provided an opportunity for LDCs to "self-nominate" to be rebased in a particular year.

On March 19, 2007, NOTL Hydro filed a self-nomination request for rebasing in 2009. Subsequently, in Board File No. EB-2006-0330, the OEB issued its list of distributors that will be rebased in 2009 – the list included NOTL Hydro. On May 27, 2008 the OEB issued a letter asking distributors who wished to be removed from the list of distributors for rate rebasing in 2009 to file a letter to that effect. NOTL Hydro decided it did not wish to be removed from this list and consequently did not file a letter to that effect.

No further Procedural Orders or directions have been issued by the OEB to the date of filing this Application.

ACCOUNTING ORDERS REQUESTED:

NOTL Hydro is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

NOTL Hydro has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the USoA in the preparation of this Application.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Town of Niagara-on-the-Lake
TOTAL SERVICE AREA:	133 sq km
RURAL SERVICE AREA:	119 sq km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	14,800
MUNICIPAL POPULATION:	14,800
BOUNDARIES:	Generally: West: Welland Canal North: Lake Ontario East: Niagara River South: Niagara Escarpment NOTL Hydro operates within the municipal boundaries of the Town of Niagara-on-the-Lake.

Maps of the NOTL Hydro Distribution Service Territory are provided in **Appendix C** (at end of Exhibit 1) as follows:

- Map of MAIN SYSTEM – 27kV and 4 kV
- Map of “OLD TOWN” - 27 kV
- Map of “OLD TOWN” - 4 kV

LIST OF NEIGHBOURING UTILITIES:

Servicing St Catharines:

Horizon Utilities Corporation
55 John Street North
Hamilton ON L8R 3M8

Mailing address:
P.O. Box 2249 Station LCD 1
Hamilton, ON L8N 3E4

Telephone: 1-866-458-1236
Website: www.horizonutilities.com

Servicing Niagara Falls:

Niagara Falls Hydro Inc.*
7447 Pin Oak Drive
P.O. Box 120
Niagara Falls ON L2E 6S9

[Division of Niagara Peninsula Energy Inc.]*

Telephone: 905- 356-2681
Website: www.niagarafallshydro.on.ca

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

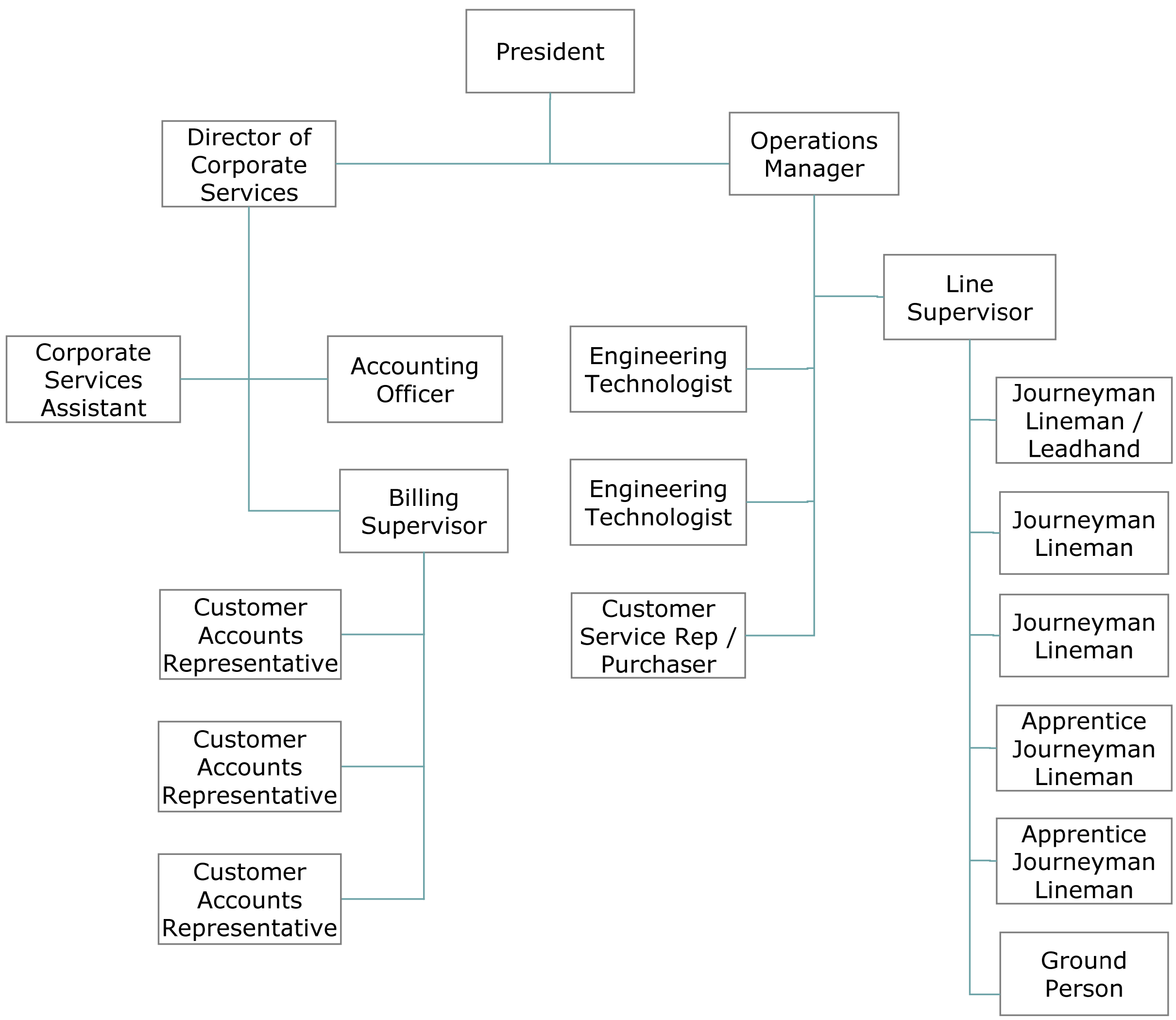
NOTL Hydro does not host any utilities within its service area.

NOTL Hydro is disputing a 6 mW load assignment from Hydro One at the Ontario Energy Board. This load assignment out of the Niagara Falls area would effectively list this supply point as Hydro One embedded.

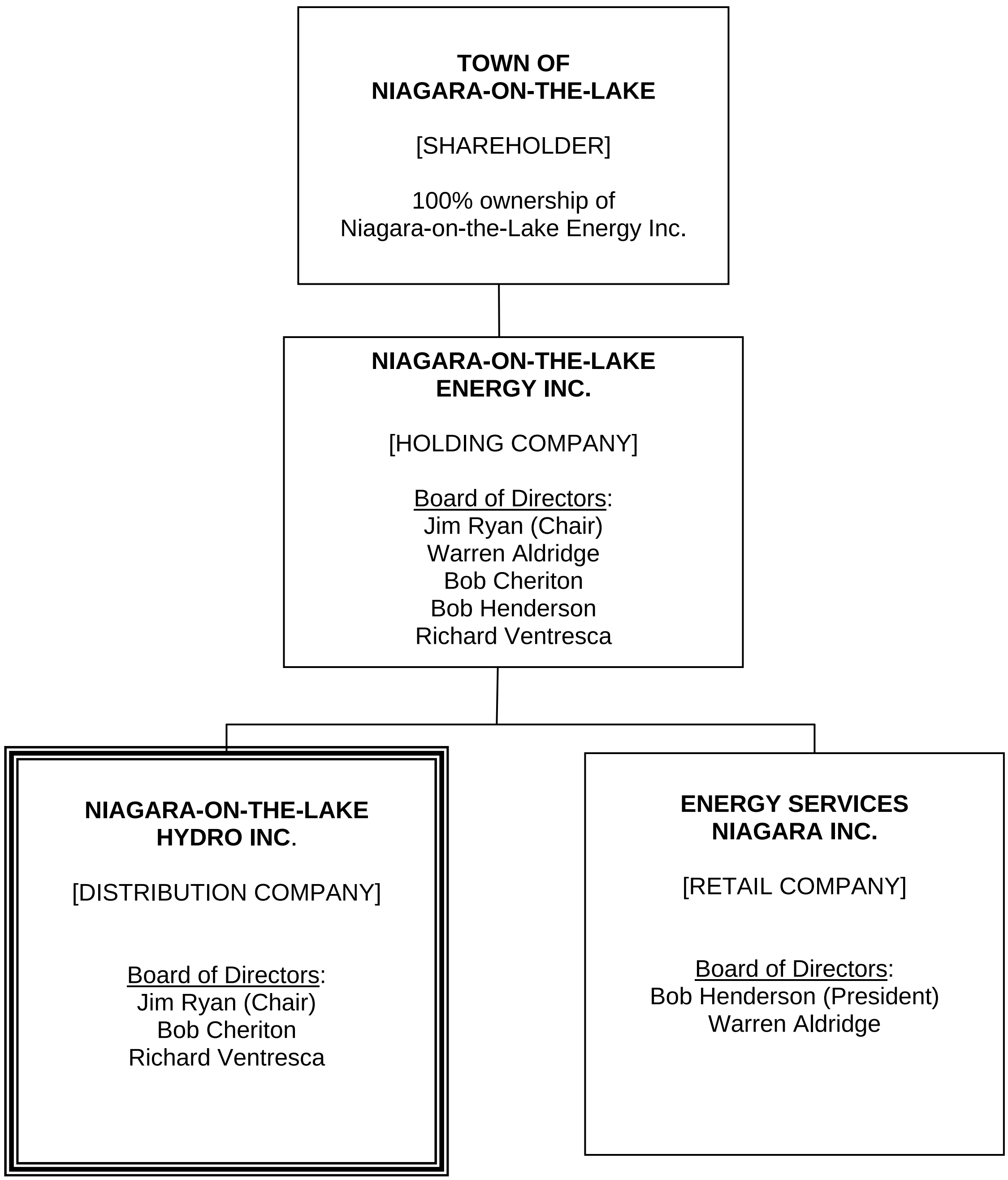
UTILITY ORGANIZATIONAL CHART:

The chart below shows NOTL Hydro's existing organizational structure of 19 full-time positions. No changes to this structure are proposed for the 2009 test year.

Niagara-on-the-Lake Hydro
Organizational Chart



CORPORATE ENTITIES RELATIONSHIPS CHART:



The President of NOTL Hydro reports to the Board of Directors of NOTL Hydro.

Niagara-on-the-Lake Energy Inc.

Niagara-on-the-Lake Energy Inc. is a wholly-owned corporation of The Town of Niagara-on-the-Lake, and was incorporated in July, 2000 under the laws of the Province of Ontario. Niagara-on-the Lake Energy is the Holding Company for two subsidiary companies.

Niagara-on-the-Lake Hydro Inc.

Niagara-on-the-Lake Hydro Inc. is a wholly-owned subsidiary of Niagara-on-the-Lake Energy Inc., and was incorporated in July, 2000 under the laws of the Province of Ontario. Niagara-on-the-Lake Hydro Inc. is regulated by the Ontario Energy Board and its principal activity is to distribute electrical power within the municipal boundaries of the Town of Niagara-on-the-Lake.

Energy Services Niagara Inc.

Energy Services Niagara Inc. is a wholly-owned subsidiary of Niagara-on-the-Lake Energy Inc., and was incorporated in July, 2000 under the laws of the Province of Ontario. The principal activities of the Company are to provide hot water tank and sentinel light rentals, water billing services for the Town of Niagara-on-the-Lake. The company also has a share of equity in a regional based fibre optic communication company.

NOTL Hydro maintains a service agreement with its affiliate, Energy Services Niagara Inc., that is reviewed on an annual basis and updated as required.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to NOTL Hydro's corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

NOTL Hydro has no Board Directives at this time.

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES:

A copy of NOTL Hydro's current Conditions of Service and Service charges are provided in **Appendix D** (at end of Exhibit 1).

PLANNED CHANGES IN CONDITIONS OF SERVICE:

NOTL Hydro is in the process of fully reviewing the current Conditions of Service and presently expects that only minor modifications will be required to a few sections. When complete, by December 31, 2008, the new Conditions of Service will continue to be in accordance with the Distribution System Code.

LIST OF WITNESSES:

The curricula vitae of NOTL Hydro's potential witnesses are listed below. Additional witnesses may be called as required during the hearing process.

Name of Witness	**Jim Huntingdon**	**David Steinschifter**	**Philip Wormwell**
Title	President	Operations Manager	Director of Corporate Services
Educational Background	Honours B.A. (Geography), Brock University	Construction Maintenance Electrician	M.A.Sc. (Industrial Engineering, University of Toronto)
	Engineering Technology, Mohawk College	Working towards B.A from University of Phoenix	M.A. (Mathematics, Cambridge University, U.K.)
Professional Designations	C.E.T.		
Employment History	Present position since 2001	Present position since March 2006	Present position since June 2004
	Operations Manager, NOTL Hydro, 1998 to 2001	Various Supervisory positions in capital construction and operational maintenance activities, Business Development, and Environmental, Health & Safety at Canadian Niagara Power, 1998 to 2006	Board Director, NOTL Hydro, 2000 to 2004
	Engineering Supervisor, NOTL Hydro, 1990 to 1998		Math tutor, Oxford Learning, 1998 to 2000
	Engineering Supervisor, Stoney Creek Hydro, 1989 to 1990		Various senior manager positions in finance and planning, Ontario Ministry of Natural Resources, 1981 to 1998
	Engineering Technician, Stoney Creek Hydro, 1985 to 1989		Various financial advisor positions, Ontario Management Board of Cabinet/ Treasury Board, 1971 to 1981
	Design Technician, Stoney Creek Hydro, 1981 to 1985		Systems Analyst, Ontario Ministry of Health, 1969 to 1971
			Management Science Analyst, British Gas, 1967 to 1969

BUDGET DIRECTIVES:

NOTL Hydro compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2008 Bridge Year and the 2009 Test Year.

Revenue Forecast

NOTL Hydro's energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2008 and 2009.

The forecast is weather normalized as outlined in **Exhibit 3, Tab 2, Schedule 2** using a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather and economic data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers, using company knowledge of local economic conditions, residential development opportunities and status of specific key customers where applicable, and historical usage patterns per customer.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2008 Bridge Year and the 2009 Test Year have been based on an in-depth review of operating priorities and requirements, using a zero-based approach where required and taking into account prior year experience. Each item was reviewed account by account for each of the forecast years.

Capital Budget

NOTL Hydro prepares an annual capital expenditure plan based on good utility practices and in conjunction with the guidelines established in our asset management policy and five-year capital plan. The asset management policy is provided in **Exhibit 2, Tab 3, Schedule 5**.

The annual plan and the rolling five-year capital plan are approved annually by the NOTL Hydro Board of Directors. The specific capital plans for the years 2006 to 2009 are discussed in detail in **Exhibit 2, Tab 3, Schedule 1**.

CHANGES IN METHODOLOGY:

NOTL Hydro is not requesting any changes in methodology in the current proceeding.

1 **CALCULATION OF REVENUE DEFICIENCY**
2 **2009 TEST YEAR**

Calculation of Revenue Deficiency

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$206,184
Distribution Revenue	$4,623,334	$4,623,334
Other Operating Revenue (Net)	$361,622	$361,622
Total Revenue	$4,984,956	$5,191,140
Distribution Costs		
Operation, Maintenance, and Administration	$1,864,661	$1,864,661
Depreciation & Amortization	$1,245,184	$1,245,184
PropertyTax	$33,450	$33,450
Capital Tax	$15,166	$15,166
Interest- Deemed Interest	$814,335	$814,335
Total Costs and Expenses	$3,972,797	$3,972,797
Utility Income Before Income Taxes	$1,012,159	$1,218,343
Net Adjustments per 2008 Pils	$27,206	$27,206
Taxable Income	$1,039,365	$1,245,550
Income Tax	$342,991	$411,031
Rate	*33.0%*	*33.0%*
Utility Income	$669,168	$807,312
Rate Base	$21,740,616	$21,740,616
Equity	43.33%	43.33%
Equity Component Rate Base	$9,420,209	$9,420,209
Income / Equity Rate Base %	7.10%	8.57%
Target Return -Equity on Rate Base	8.57%	8.57%
Return- Equity on Rate Base	$807,312	$807,312
Revenue Deficiency	$138,143	
Revenue Deficiency (Gross-up)	$206,184	

3

4

CAUSES OF REVENUE DEFICIENCY:

NOTL Hydro's net revenue deficiency is calculated as $138,143 and when grossed up for PILs, the revenue deficiency is $206,184 .

NOTL Hydro's calculation of its 2009 revenue deficiency is provided in **Exhibit 1, Tab 1, Schedule 23** and **Exhibit 7, Tab 1, Schedule 1**.

The revenue deficiency is primarily the result of:

- Projected increases in OM&A costs including depreciation expense for the 2009 Test Year as discussed in further detail in **Exhibit 4, Tab 1** (Overview) and **Exhibit 4, Tab 2** (OM&A Costs); and
- Projected increases in investments in gross assets and, as a result, the rate base on which the rate of return is based, as discussed further in **Exhibit 2, Tab 1** (Rate Base) and **Exhibit 2, Tab 2** (Gross Assets – Property, Plant and Equipment)

FINANCIAL STATEMENTS – 2006 and 2007:

The NOTL Hydro Audited 2006 Financial Statements and Audited 2007 Financial Statements are provided in **Appendix E** (at end of Exhibit 1).

The 2007 Federal T2 tax return and the 2007 Ontario CT23 tax return are also provided in **Appendix F** (at end of Exhibit 1).

PRO FORMA FINANCIAL STATEMENTS - 2008 AND 2009:

The NOTL Hydro Pro Forma Statements for the 2008 Bridge Year and the 2009 Test Year are provided below. The 2009 Test Year Statements reflect the proposed distribution rates to be effective May 1, 2009.

Niagara-on-the-Lake Hydro Inc.
2008 BALANCE SHEET

Account Description	Total
Current Assets	
1005-Cash	519,335.55
1010-Cash Advances and Working Funds	300.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	
1100-Customer Accounts Receivable	1,545,165.22
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	281,000.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	964,481.91
1120-Accrued Utility Revenues	1,724,880.17
1130-Accumulated Provision for Uncollectible Accounts--Credit	(15,000.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1170-Notes receivable	7,598.71
1180-Prepayments	75,539.49
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
Current Assets Total	**5,103,301.05**
Inventory	
1330-Plant Materials and Operating Supplies	204,378.01
1305-Fuel Stock	-
1350-Other Materials and Supplies	-
Inventory Total	**204,378.01**
Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1410-Other Special or Collateral Funds	354,775.03
1460-Other Non-Current Assets	609.59
Non-Current Assets Total	**355,384.62**
Other Assets and Deferred Charges	
1508-Other Regulatory Assets	109,036.90
1518-RCVARetail	38,620.42
1525-Miscellaneous Deferred Debits	-
1548-RCVASTR	34,786.02
1550-LV Variance Account	20,715.54
1555-Smart Meters Capital Variance Account	(33,944.44)
1556-Smart Meters OM&A Variance Account	-

2008 balance sheet

1562-Deferred Payments in Lieu of Taxes	(108,391.41)
1565-Conservation and Demand Management Expenditures and Recoveries	-
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(325,024.43)
1582-RSVAONE-TIME	11,923.62
1584-RSVANW	125,145.30
1586-RSVACN	(351,948.58)
1588-RSVAPOWER	136,342.52
1589-RSVAPOWER - Global Adjustment	140,317.86
1590-Recovery of Regulatory Asset Balances	(318,320.75)
Other Assets and Deferred Charges Total	**(520,741.45)**

Intangible Plant	
1606-Organization	25,037.68
Intangible Plant Total	**25,037.68**

Distribution Plant	
1805-Land	261,993.71
1806-Land Rights	-
1808-Buildings and Fixtures	-
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	5,311,653.98
1820-Distribution Station Equipment - Normally Primary below 50 kV	270,451.74
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	4,363,730.04
1835-Overhead Conductors and Devices	6,042,216.08
1840-Underground Conduit	3,927,229.43
1845-Underground Conductors and Devices	7,339,729.60
1850-Line Transformers	6,814,715.19
1855-Services	1,967,772.58
1860-Meters	1,059,528.69
Distribution Plant Total	**37,359,021.04**

General Plant	
1905-Land	49,000.00
1906-Land Rights	-
1908-Buildings and Fixtures	934,793.68
1915-Office Furniture and Equipment	174,151.23
1920-Computer Equipment - Hardware	308,260.16

2008 balance sheet

1925-Computer Software	941,659.47
1930-Transportation Equipment	975,199.11
1935-Stores Equipment	18,038.90
1940-Tools, Shop and Garage Equipment	414,945.83
1945-Measurement and Testing Equipment	-
1950-Power Operated Equipment	-
1955-Communication Equipment	36,768.31
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	325,463.49
1995-Contributions and Grants - Credit	(4,977,564.85)
General Plant Total	**(799,284.67)**

Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
Other Capital Assets Total	**-**

Accumulated Amortization	
2105-Accum. Amortization of intangible plant - Organization	(10,223.37)
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(17,282,748.19)
2160-Accumulated Amortization of Other Utility Plant	-
Accumulated Amortization Total	**(17,292,971.56)**

Total Assets	**24,434,124.72**

Current Liabilities	
2205-Accounts Payable	761,941.16
2208-Customer Credit Balances	4,558.64
2210-Current Portion of Customer Deposits	181,491.25
2220-Miscellaneous Current and Accrued Liabilities	514,884.80
2240-Accounts Payable to Associated Companies	-
2250-Debt Retirement Charges(DRC) Payable	200,000.00
2252-Transmission charges payable	341,730.46
2256-IESO fees and penalties payable	1,029,595.71
2260-Current portion of long term debt	4,086,043.32
2268-Accrued interest on liong term debt	1,144.91
2290-Commodity Taxes	19,497.42
2292-Payroll Deductions / Expenses Payable	2,142.29
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-
2296-Future Income Taxes - Current	-

2008 balance sheet

Current Liabilities Total	**7,143,029.95**
Non-Current Liabilities	
2306-Employee Future Benefits	452,694.22
2310-Vested Sick Leave Liability	19,360.80
2320-Other Miscellaneous Non-Current Liabilities	-
2335-Long Term Customer Deposits	354,775.03
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	-
Non-Current Liabilities Total	**826,830.05**
Long-Term Debt	
2550-Advances from Associated Companies	6,566,333.12
Long-Term Debt Total	**6,566,333.12**
Shareholders' Equity	
3005-Common Shares Issued	2,632,307.61
3010-Contributed Surplus	-
3022-Development charges transferred to equity	4,269,025.51
3030-Miscellaneous Paid-In Capital	-
3045-Unappropriated Retained Earnings	2,280,922.48
3046-Balance Transferred From Income	762,059.00
3047-Other Appropriated Retained Earnings	(46,383.00)
3049-Dividends Payable-Common Shares	-
Shareholders' Equity Total	**9,897,931.60**
Total Liabilities & Shareholder's Equity	**24,434,124.72**
Balance Sheet Total	0.00

Niagara-on-the-Lake Hydro Inc.
2008 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
Sales of Electricity	
4006-Residential Energy Sales	(4,194,548.50)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(66,661.54)
4030-Sentinel Lighting Energy Sales	(3,124.71)
4035-General Energy Sales	(7,292,401.26)
4050-Revenue Adjustment	
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	
4062-Billed WMS	(1,180,035.63)
4066-Billed NW	(918,884.37)
4068-Billed CN	(347,926.38)
Sales of Electricity Total	**(14,003,582.38)**
Revenues From Services - Distribution	
4080-Distribution Services Revenue	(4,587,892.32)
4082-Retail Services Revenues	(7,286.00)
4084-Service Transaction Requests (STR) Revenues	(218.33)
4090-Electric Services Incidental to Energy Sales	-
Revenues From Services - Distirbution Total	**(4,595,396.65)**
Other Operating Revenues	
4210-Rent from Electric Property	(70,000.00)
4220-Other Electric Revenues	
4225-Late Payment Charges	(48,070.00)
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	(45,430.00)
Other Operating Revenues Total	**(163,500.00)**
Other Income & Deductions	
4315-Revenues from electric plant leased to others	-
4325-Revenues from Merchandise, Jobbing, Etc.	(60,000.00)
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-
4335-Profits and Losses from Financial Instrument Hedges	(34,000.00)
4355-Gain on Disposition of Utility and Other Property	-
4360-Loss on disposition of utility & other property	10,000.00
4375-Revenues of Non-Utility Operations	-
4380-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	(15,000.00)

2008 income statement

4398-Foreign Exchange Gains and Losses, Including Amortization	-
Other Income & Deductions Total	**(99,000.00)**
Investment Income	
4405-Interest and Dividend Income	(41,471.98)
Investment Income Total	**(41,471.98)**
Power Supply Expenses	
4705-Power Purchased	11,485,736.00
4708-Charges-WMS	1,180,035.63
4710-Cost of Power Adjustments	71,000.00
4714-Charges-NW	918,884.37
4715-System Control and Load Dispatching	
4716-Charges-CN	347,926.38
4730-Rural Rate Assistance Expense	-
Power Supply Expenses Total	**14,003,582.38**
Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	92,297.53
5010-Load Dispatching	30,679.31
5012-Station Buildings and Fixtures Expense	-
5014-Transformer Station Equipment - Operation Labour	5,396.20
5015-Transformer Station Equipment - Operation Supplies and Expenses	12,950.00
5016-Distribution Station Equipment - Operation Labour	5,100.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	-
5020-Overhead Distribution Lines and Feeders - Operation Labour	23,471.58
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	22,483.67
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	2,627.18
5040-Underground Distribution Lines and Feeders - Operation Labour	15,813.63
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	4,338.17
5055-Underground Distribution Transformers - Operation	2,836.60
5065-Meter Expense	10,618.65
5070-Customer Premises - Operation Labour	9,457.91
5075-Customer Premises - Materials and Expenses	37,063.27
5085-Miscellaneous Distribution Expense	83,456.15
5095-Overhead Distribution Lines and Feeders - Rental Paid	18,800.00
5096-Other Rent	-
Distribution Expenses - Operation Total	**377,389.85**
Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	79,928.27
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-
5112-Maintenance of transformer station equipment	13,263.09
5114-Maintenance of Distribution Station Equipment	4,755.44

2008 income statement

5120-Maintenance of Poles, Towers and Fixtures	33,715.82
5125-Maintenance of Overhead Conductors and Devices	53,205.62
5130-Maintenance of Overhead Services	57,504.59
5135-Overhead Distribution Lines and Feeders - Right of Way	77,682.62
5145-Maintenance of Underground Conduit	1,100.00
5150-Maintenance of Underground Conductors and Devices	20,049.98
5155-Maintenance of Underground Services	53,204.71
5160-Maintenance of Line Transformers	62,940.80
5175-Maintenance of Meters	17,320.51
Distribution Expenses - Maintenance Total	**474,671.43**
Billing and Collecting	
5305-Supervision	12,860.57
5310-Meter Reading Expense	48,608.84
5315-Customer Billing	156,687.17
5320-Collecting	74,217.61
5325-Collecting - cash over and short	-
5330-Collection Charges	
5335-Bad Debt Expense	20,000.00
5340-Miscellaneous Customer Accounts Expenses	-
Billing and Collecting Total	**312,374.19**
Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	-
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Misc. Customer service & informational expenses	1,000.00
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
Community Relations Total	**1,000.00**
Administrative and General Expenses	
5605-Executive Salaries and Expenses	63,826.02
5610-Management Salaries and Expenses	93,875.41
5615-General Administrative Salaries and Expenses	112,535.99
5620-Office Supplies and Expenses	25,510.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	28,500.00
5635-Property Insurance	21,000.00
5640-Injuries and Damages	28,000.00
5645-Employee Pensions and Benefits	22,000.00
5655-Regulatory Expenses	22,630.00
5660-General Advertising Expenses	1,000.00

2008 income statement

5665-Miscellaneous General Expenses	50,000.00
5675-Maintenance of General Plant	114,806.76
5680-ESA Fees	5,370.00
Administrative and General Expenses Total	**589,054.19**
Amortization Expense	
5705-Amortization Expense - Organization	1,251.84
5705-Amortization Expense - Property, Plant, and Equipment	1,211,455.81
Amortization Expense Total	**1,212,707.65**
Interest Expense	
6005-Interest on Long Term Debt	717,960.68
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	15,000.00
6042-Allowance For Other Funds Used During Construction	
Interest Expense Total	**732,960.68**
Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes - Property Tax	33,800.00
6105-Taxes Other Than Income Taxes - Capital Tax	18,881.59
Taxes Other Than Income Taxes Total	**52,681.59**
Income Taxes	
6110-Income Taxes	384,470.05
6115-Provision for Future Income Taxes	
Income Taxes Total	**384,470.05**
Extraordinary & Other Items	
6205-Donations	-
6310-Extraordinary Deductions	
Extraordinary & Other Items Total	**-**
Net Income	**(762,059.00)**

Niagara-on-the-Lake Hydro Inc.
2009 BALANCE SHEET

Account Description	Total
Current Assets	
1005-Cash	572,982.22
1010-Cash Advances and Working Funds	300.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	
1100-Customer Accounts Receivable	1,557,376.40
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	281,000.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	-
1110-Other Accounts Receivable	1,046,368.22
1120-Accrued Utility Revenues	1,695,626.44
1130-Accumulated Provision for Uncollectible Accounts--Credit	(15,000.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1170-Notes receivable	600.00
1180-Prepayments	62,206.49
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
Current Assets Total	**5,201,459.78**

Inventory	
1330-Plant Materials and Operating Supplies	203,623.88
1305-Fuel Stock	-
1350-Other Materials and Supplies	-
Inventory Total	**203,623.88**

Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1410-Other Special or Collateral Funds	354,171.68
1460-Other Non-Current Assets	9.59
Non-Current Assets Total	**354,181.27**

Other Assets and Deferred Charges	
1508-Other Regulatory Assets	112,238.42
1518-RCVARetail	44,549.22
1525-Miscellaneous Deferred Debits	-
1548-RCVASTR	47,332.13
1550-LV Variance Account	21,345.49
1555-Smart Meters Capital Variance Account	(58,232.50)

2009 balance sheet

1556-Smart Meters OM&A Variance Account	-
1562-Deferred Payments in Lieu of Taxes	(111,323.03)
1565-Conservation and Demand Management Expenditures and Recoveries	-
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(335,445.23)
1582-RSVAONE-TIME	12,265.40
1584-RSVANW	128,897.97
1586-RSVACN	(362,733.82)
1588-RSVAPOWER	140,510.38
1589-RSVAPOWER - Global Adjustment	145,020.83
1590-Recovery of Regulatory Asset Balances	(159,320.02)
Other Assets and Deferred Charges Total	**(374,894.76)**

Intangible Plant	
1606-Organization	25,037.68
Intangible Plant Total	**25,037.68**

Distribution Plant	
1805-Land	301,993.71
1806-Land Rights	-
1808-Buildings and Fixtures	-
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	5,316,653.98
1820-Distribution Station Equipment - Normally Primary below 50 kV	270,451.74
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	4,475,396.04
1835-Overhead Conductors and Devices	6,376,382.08
1840-Underground Conduit	4,636,395.43
1845-Underground Conductors and Devices	7,746,395.60
1850-Line Transformers	6,995,547.19
1855-Services	2,067,772.58
1860-Meters	1,079,528.69
Distribution Plant Total	**39,266,517.04**

General Plant	
1905-Land	49,000.00
1906-Land Rights	-
1908-Buildings and Fixtures	954,793.68
1915-Office Furniture and Equipment	179,151.23
1920-Computer Equipment - Hardware	318,260.16

2009 balance sheet

1925-Computer Software	991,659.47
1930-Transportation Equipment	975,199.11
1935-Stores Equipment	38,038.90
1940-Tools, Shop and Garage Equipment	419,945.83
1945-Measurement and Testing Equipment	-
1950-Power Operated Equipment	-
1955-Communication Equipment	36,768.31
1960-Miscellaneous Equipment	-
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	335,463.49
1995-Contributions and Grants - Credit	(5,127,564.85)
General Plant Total	**(829,284.67)**

Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
Other Capital Assets Total	**-**

Accumulated Amortization	
2105-Accum. Amortization of intangible plant - Organization	(11,475.21)
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(18,614,425.58)
2160-Accumulated Amortization of Other Utility Plant	-
Accumulated Amortization Total	**(18,625,900.79)**

Total Assets	**25,220,739.43**

Current Liabilities	
2205-Accounts Payable	786,046.89
2208-Customer Credit Balances	4,922.30
2210-Current Portion of Customer Deposits	188,225.15
2220-Miscellaneous Current and Accrued Liabilities	535,185.94
2240-Accounts Payable to Associated Companies	-
2250-Debt Retirement Charges(DRC) Payable	200,000.00
2252-Transmission charges payable	464,470.42
2256-IESO fees and penalties payable	1,029,595.71
2260-Current portion of long term debt	3,792,613.16
2268-Accrued interest on liong term debt	1,051.65
2290-Commodity Taxes	19,497.42
2292-Payroll Deductions / Expenses Payable	3,114.64
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-
2296-Future Income Taxes - Current	-
Current Liabilities Total	**7,024,723.27**

2009 balance sheet

Non-Current Liabilities	
2306-Employee Future Benefits	453,094.22
2310-Vested Sick Leave Liability	19,360.80
2320-Other Miscellaneous Non-Current Liabilities	-
2335-Long Term Customer Deposits	354,171.68
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	-
Non-Current Liabilities Total	**826,626.70**

Long-Term Debt	
2550-Advances from Associated Companies	6,566,333.12
Long-Term Debt Total	**6,566,333.12**

Shareholders' Equity	
3005-Common Shares Issued	2,632,307.61
3010-Contributed Surplus	-
3022-Development charges transferred to equity	4,269,025.51
3030-Miscellaneous Paid-In Capital	-
3045-Unappropriated Retained Earnings	3,042,981.48
3046-Balance Transferred From Income	905,124.74
3047-Other Appropriated Retained Earnings	(46,383.00)
3049-Dividends Payable-Common Shares	-
Shareholders' Equity Total	**10,803,056.34**

Total Liabilities & Shareholder's Equity	**25,220,739.43**

Balance Sheet Total	0.00

Niagara-on-the-Lake Hydro Inc.
2009 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
Sales of Electricity	
4006-Residential Energy Sales	(3,741,945.38)
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	(61,278.03)
4030-Sentinel Lighting Energy Sales	-
4035-General Energy Sales	(6,503,022.92)
4050-Revenue Adjustment	
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	
4062-Billed WMS	(1,189,256.05)
4066-Billed NW	(886,554.12)
4068-Billed CN	(324,619.48)
Sales of Electricity Total	**(12,706,675.99)**
Revenues From Services - Distribution	
4080-Distribution Services Revenue	(4,859,221.32)
4082-Retail Services Revenues	(7,286.00)
4084-Service Transaction Requests (STR) Revenues	(218.33)
4090-Electric Services Incidental to Energy Sales	-
Revenues From Services - Distirbution Total	**(4,866,725.66)**
Other Operating Revenues	
4210-Rent from Electric Property	(70,000.00)
4220-Other Electric Revenues	
4225-Late Payment Charges	(48,070.00)
4230-Sales of Water and Water Power	
4235-Miscellaneous Service Revenues	(45,430.00)
Other Operating Revenues Total	**(163,500.00)**
Other Income & Deductions	
4315-Revenues from electric plant leased to others	-
4325-Revenues from Merchandise, Jobbing, Etc.	(60,000.00)
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-
4335-Profits and Losses from Financial Instrument Hedges	(34,000.00)
4355-Gain on Disposition of Utility and Other Property	-
4360-Loss on disposition of utility & other property	-
4375-Revenues of Non-Utility Operations	-
4380-Expenses of Non-Utility Operations	-
4390-Miscellaneous Non-Operating Income	(15,000.00)
4398-Foreign Exchange Gains and Losses, Including Amortization	-
Other Income & Deductions Total	**(109,000.00)**

1

2009 income statement

Investment Income	
4405-Interest and Dividend Income	(51,914.51)
Investment Income Total	**(51,914.51)**
Power Supply Expenses	
4705-Power Purchased	10,270,746.34
4708-Charges-WMS	1,189,256.05
4710-Cost of Power Adjustments	35,500.00
4714-Charges-NW	886,554.12
4715-System Control and Load Dispatching	
4716-Charges-CN	324,619.48
4730-Rural Rate Assistance Expense	-
Power Supply Expenses Total	**12,706,675.99**
Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	90,579.85
5010-Load Dispatching	30,683.02
5012-Station Buildings and Fixtures Expense	-
5014-Transformer Station Equipment - Operation Labour	5,360.55
5015-Transformer Station Equipment - Operation Supplies and Expenses	13,250.00
5016-Distribution Station Equipment - Operation Labour	6,100.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	-
5020-Overhead Distribution Lines and Feeders - Operation Labour	26,692.40
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	24,920.41
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	2,628.45
5040-Underground Distribution Lines and Feeders - Operation Labour	18,859.96
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	5,341.36
5055-Underground Distribution Transformers - Operation	2,881.68
5065-Meter Expense	13,278.24
5070-Customer Premises - Operation Labour	7,985.98
5075-Customer Premises - Materials and Expenses	40,075.61
5085-Miscellaneous Distribution Expense	66,272.54
5095-Overhead Distribution Lines and Feeders - Rental Paid	18,800.00
5096-Other Rent	-
Distribution Expenses - Operation Total	**373,710.07**
Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	79,393.67
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-
5112-Maintenance of transformer station equipment	20,784.65
5114-Maintenance of Distribution Station Equipment	5,271.71
5120-Maintenance of Poles, Towers and Fixtures	33,589.76
5125-Maintenance of Overhead Conductors and Devices	52,566.55
5130-Maintenance of Overhead Services	57,774.50
5135-Overhead Distribution Lines and Feeders - Right of Way	92,563.83

2009 income statement

5145-Maintenance of Underground Conduit	1,100.00
5150-Maintenance of Underground Conductors and Devices	20,087.48
5155-Maintenance of Underground Services	53,253.07
5160-Maintenance of Line Transformers	88,679.84
5175-Maintenance of Meters	16,294.19
Distribution Expenses - Maintenance Total	**521,359.23**
Billing and Collecting	
5305-Supervision	13,530.49
5310-Meter Reading Expense	49,767.84
5315-Customer Billing	159,131.31
5320-Collecting	76,367.90
5325-Collecting - cash over and short	-
5330-Collection Charges	
5335-Bad Debt Expense	20,000.00
5340-Miscellaneous Customer Accounts Expenses	-
Billing and Collecting Total	**318,797.53**
Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	-
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Misc. Customer service & informational expenses	1,020.00
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
Community Relations Total	**1,020.00**
Administrative and General Expenses	
5605-Executive Salaries and Expenses	67,260.06
5610-Management Salaries and Expenses	98,680.33
5615-General Administrative Salaries and Expenses	115,448.58
5620-Office Supplies and Expenses	25,430.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	67,283.33
5635-Property Insurance	20,600.00
5640-Injuries and Damages	27,700.00
5645-Employee Pensions and Benefits	22,000.00
5655-Regulatory Expenses	25,475.00
5660-General Advertising Expenses	1,020.00
5665-Miscellaneous General Expenses	50,450.00
5675-Maintenance of General Plant	123,056.93
5680-ESA Fees	5,370.00
Administrative and General Expenses Total	**649,774.24**

2009 income statement

Amortization Expense	
5705-Amortization Expense - Organization	1,251.84
5705-Amortization Expense - Property, Plant, and Equipment	1,243,932.64
Amortization Expense Total	**1,245,184.48**
Interest Expense	
6005-Interest on Long Term Debt	701,522.10
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	15,000.00
6042-Allowance For Other Funds Used During Construction	
Interest Expense Total	**716,522.10**
Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes - Property Tax	33,450.00
6105-Taxes Other Than Income Taxes - Capital Tax	15,166.38
Taxes Other Than Income Taxes Total	**48,616.38**
Income Taxes	
6110-Income Taxes	411,031.41
6115-Provision for Future Income Taxes	
Income Taxes Total	**411,031.41**
Extraordinary & Other Items	
6205-Donations	-
6310-Extraordinary Deductions	
Extraordinary & Other Items Total	**-**
Net Income	**(905,124.74)**

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED:

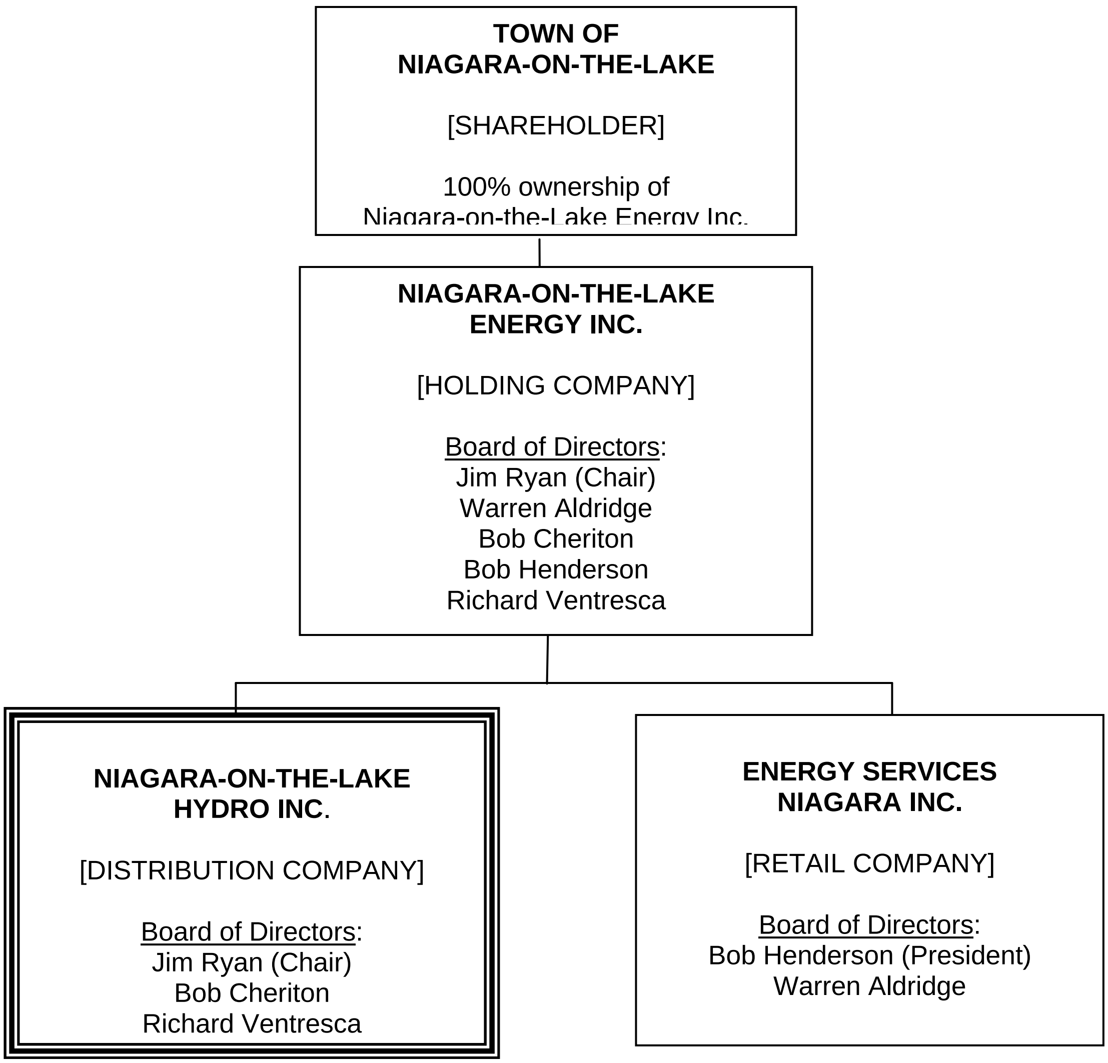
NOTL Hydro advises that because the 2006 and 2007 Audited Financial Statements do not vary from the regulatory financial results filed in this Application, a reconciliation between financial statements and financial results filed has not been provided.

PROPOSED ACCOUNTING TREATMENT FOR PROJECTS WITH A PROJECT LIFE CYCLE GREATER THAN ONE YEAR

NOTL Hydro does not currently capture the cost of funds on CWIP and therefore has not reflected any amounts concerning this practice in this application.

INFORMATION ON PARENT AND SUBSIDIARIES

The corporate entities relationship chart below (also provided in **Exhibit 1, Tab 1, Schedule 15**) shows that NOTL Hydro has no subsidiaries. The parent company is Niagara-on-the-Lake Energy Inc.



The parent and holding company, Niagara-on-the-Lake Energy Inc., is a wholly-owned corporation of The Town of Niagara-on-the-Lake, and was incorporated in July, 2000 under the laws of the Province of Ontario. The parent does not publish an annual report.

APPENDICES TO EXHIBIT 1

Appendix	Contents	Referenced from:
A	Schedule of Proposed Rates and Charges	Exhibit 1, Tab 1, Schedule 3 and Exhibit 1, Tab 1, Schedule 6
B	Distributor Licence	Exhibit 1, Tab 1, Schedule 4
C	Distribution System Maps	Exhibit 1, Tab 1, Schedule 11
D	Conditions of Service	Exhibit 1, Tab 1, Schedule 18
E	Audited Financial Statements	
	Audited Financial Statements at December 31, 2006	Exhibit 1, Tab 2, Schedule 1
	Audited Financial Statements at December 31, 2007	Exhibit 1, Tab 2, Schedule 1
F	Federal T2 Tax Return, 2007	Exhibit 1, Tab 2, Schedule 1
	Ontario CT23 Tax Return, 2007	Exhibit 1, Tab 2, Schedule 1

APPENDIX A

Schedule of Proposed Rates and Charges

Referenced from:

- Exhibit 1, Tab 1, Schedules 2, 3 and 6

Also set out in:

- Exhibit 9, Tab 1, Schedule 7**.**

RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges
Effective May 1, 2009

Customer Class	Item Description	Unit	Rate ($)
RESIDENTIAL			
	Monthly Service Charge	per month	19.08
	Distribution Volumetric Rate	per kWh	0.0134
	LRAM and SSM Rate Rider	per kWh	0.0001
	Smart Meter Rate Rider	per month	1.00
	DVA Recovery Rate Rider	per kWh	0.0003
GENERAL SERVICE < 50 kW			
	Monthly Service Charge	per month	47.83
	Distribution Volumetric Rate	per kWh	0.0144
	LRAM and SSM Rate Rider	per kWh	0.0001
	Smart Meter Rate Rider	per month	1.00
	DVA Recovery Rate Rider	per kWh	0.0003
GENERAL SERVICE > 50 kW			
	Monthly Service Charge	per month	370.25
	Distribution Volumetric Rate	per kW	2.8856
	Smart Meter Rate Rider	per month	1.00
	DVA Recovery Rate Rider	per kW	0.0629
STREET LIGHTING			
	Monthly Service Charge	per month	3.01
	Distribution Volumetric Rate	per kW	11.7906
	DVA Recovery Rate Rider	per kW	0.1291
UNMETERED SCATTERED LOAD			
	Monthly Service Charge	per month	36.30
	Distribution Volumetric Rate	per kWh	0.0109
	DVA Recovery Rate Rider	per kWh	0.0045

RATES SCHEDULE (Part 2)

Schedule of Distribution Rates and Charges

Effective May 1, 2009

Specific Service Charges		
Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for Previous Billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Account History	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque Charge (plus bank charges)	$	15.00
Charge to Certify Cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – No Disconnection	$	30.00
Disconnect/Reconnect Charges at Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charges at Meter – After Regular Hours	$	185.00
Disconnect/Reconnect Charges at Pole– During Regular Hours	$	185.00
Disconnect/Reconnect Charges at Pole – After Regular Hours	$	415.00
Service Call – Customer-owned Equipment – During Regular Hours	$	30.00
Service Call – Customer-owned Equipment – After Regular Hours	$	165.00
Install/Remove Load Control Device – During Regular Hours	$	65.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Temporary Service Install & Remove – Overhead – No Transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service Install & Remove – Overhead – with Transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Specific Charge for Bell Canada Access to the Power Poles – per pole/year	$	18.36
Note: Specific Charge for Bell Canada Access to the Power Poles is valid only until the existing joint-use agreement is terminated.		

Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.56
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00

Loss Factors	
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0501
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0156
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0396
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0055

APPENDIX B

Distributor Licence

Referenced from:

- Exhibit 1, Tab 1, Schedule 3

Electricity Distribution Licence

ED-2002-0547

Niagara-on-the-Lake Hydro Inc.

Valid Until
March 31, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: October 16, 2003

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

1 Definitions 1

In this Licence: 2

“**Accounting Procedures Handbook**” means the handbook, approved by the Board which 3
specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

“**Act**” means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 4

“**Affiliate Relationships Code for Electricity Distributors and Transmitters**” means 5
the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

“**distribution services**”means services related to the distribution of electricity and the serv- 6
ices the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

“**Distribution System Code**” means the code approved by the Board which, among other 7
things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

“**Electricity Act**” means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A; 8

“**Licensee**” means: Niagara-on-the-Lake Hydro Inc.; 9

“**Market Rules**” means the rules made under section 32 of the Electricity Act; 10

“**Performance Standards**” means the performance targets for the distribution and connec- 11
tion activities of the Licensee as established by the Board in accordance with section 83 of the Act;

“**Rate Order**” means an Order or Orders of the Board establishing rates the Licensee is per- 12
mitted to charge;

“**regulation**” means a regulation made under the Act or the Electricity Act; 13

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

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

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

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

2 Interpretation 18

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 19

3 Authorization 20

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence: 21

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; 22

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and 23

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act. 24

4 Obligation to Comply with Legislation, Regulations and Market Rules 25

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation. 26

4.2 The Licensee shall comply with all applicable Market Rules. 27

5 Obligation to Comply with Codes 28

5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence: 29

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 30

b) the Distribution System Code; 31

c) the Retail Settlement Code; and 32

d) the Standard Supply Service Code. 33

5.2 The Licensee shall: 34

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and 35

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 36

6 Obligation to Provide Non-discriminatory Access 37

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee’s distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence. 38

7 Obligation to Connect 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in writing. 42

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

b) the owner, occupant or other person in charge of the building requests the connection in writing. 45

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board. 46

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence. 47

8 Obligation to Sell Electricity 48

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board. 49

9 Obligation to Maintain System Integrity 50

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board. 51

10 Market Power Mitigation Rebates 52

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 53

11 Distribution Rates 54

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

12 Separation of Business Activities 56

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

13 Expansion of Distribution System 58

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

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

14 Provision of Information to the Board 61

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

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

15 Restrictions on Provision of Information 64

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

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

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

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

c) for law enforcement purposes; or 69

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

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

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

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

16 Customer Complaint and Dispute Resolution 74

16.1 The Licensee shall: 75

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

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

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

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

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

17 Term of Licence 81

17.1 This Licence shall take effect on October 16, 2003 and expire on March 31, 2023. The term of this 82
Licence may be extended by the Board.

18 Fees and Assessments 83

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 84

19 Communication 85

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters 86
related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing. 87

19.3 All written communication is to be regarded as having been given by the sender and received by 88
the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier; 89

b) ten (10) business days after the date of posting if the communication is sent by regular mail; 90
and

c) when received by facsimile transmission by the addressee, according to the sender's trans- 91
mission report.

20 Copies of the Licence 92

20.1 The Licensee shall: 93

a) make a copy of this Licence available for inspection by members of the public at its head 94
office and regional offices during normal business hours; and

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a 95
fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 96

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence. 97

The municipal boundaries of the Town of Niagara-on-the-Lake as of January 1, 1970. 98

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 99

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act. 100

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders. 101

SCHEDULE 3 LIST OF CODE EXEMPTIONS 102

This Schedule specifies any specific Code requirements from which the Licensee has been exempted. 103

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it. 104

APPENDIX A MARKET POWER MITIGATION REBATES 105

1 Definitions and Interpretation 106

In this Licence, 107

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 108

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates; 109

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 110

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 111

2 Information Given to IMO 112

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 113

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 114

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 115

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to: 116

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 117

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 118

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 119

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment. 120

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period. 121

3 Pass Through of Rebate 122

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 123

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented; 124

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 125

c embedded distributors to whom the distributor distributes electricity. 126

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor. 127

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement: 128

“ONTARIO POWER GENERATION INC. rebate” 129

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 130

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 131

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 132

Filed: August 7, 2008

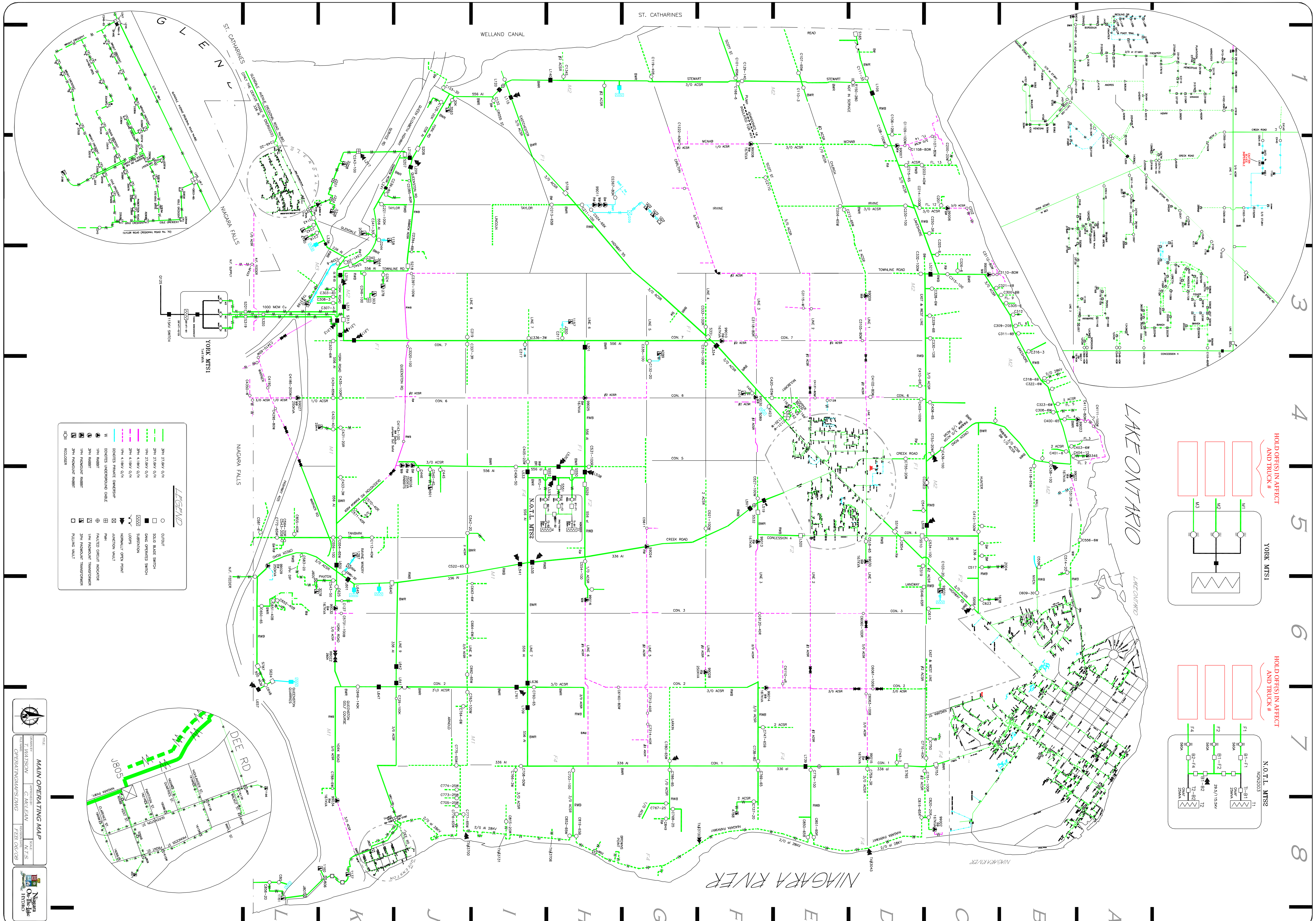
APPENDIX C

Distribution System Maps

- Map of MAIN SYSTEM – 27kV and 4 kV
- Map of “OLD TOWN” - 27 kV
- Map of “OLD TOWN” - 4 kV

Referenced from:

- Exhibit 1, Tab 1, Schedule 10



ST. CATHARINES
WELLAND CANAL
NIAGARA FALLS
LAKE ONTARIO
NIAGARA RIVER
YORK MTS1
N.O.T.L. MTS2
HOLD OFF(S) IN AFFECT AND TRUCK #
HOLD OFF(S) IN AFFECT AND TRUCK #
LEGEND
MAIN OPERATING MAP
OPERATINGMAPS.DWG
TOWNLINE ROAD
CREEK ROAD
CON. 7
CON. 6
CON. 5
CON. 3
CON. 2
CON. 1
TAYLOR
STEWART
MCNAB
IRVINE
GLENDALE
TANBARK
NIAGARA PARKWAY
DEE RD
J805
1
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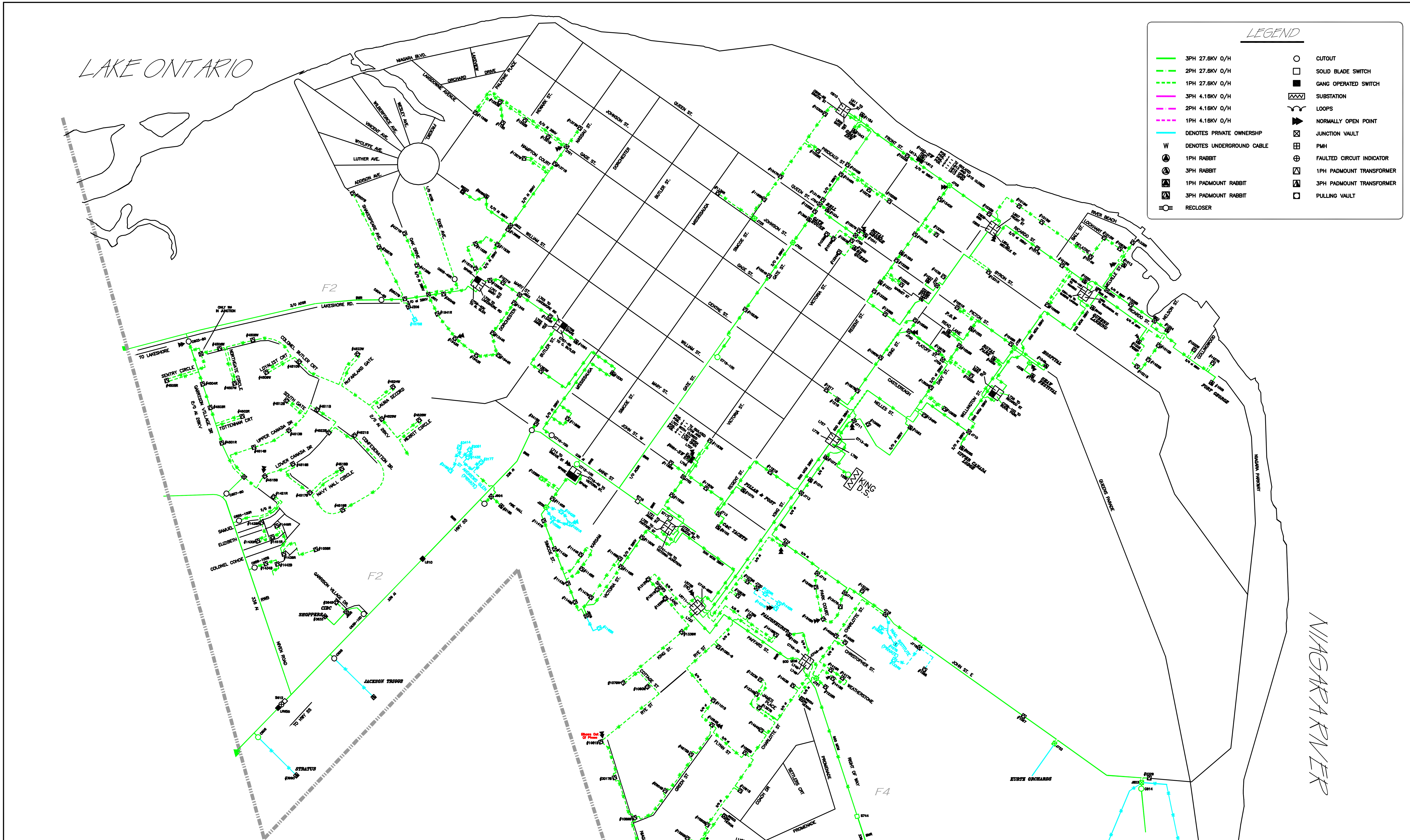


OLD TOWN 27KV OPERATING MAP

DRAWN BY: T. WATSON
APPROVED BY: C. McLEAN
SCALE: N.T.S.
FILE NAME:
REVISION DATE:

Niagara On-The-Lake HYDRO

LAKE ONTARIO
NIAGARA RIVER
LEGEND
3PH 27.6KV O/H
2PH 27.6KV O/H
1PH 27.6KV O/H
3PH 4.16KV O/H
2PH 4.16KV O/H
1PH 4.16KV O/H
DENOTES PRIVATE OWNERSHP
W DENOTES UNDERGROUND CABLE
1PH RABBIT
3PH RABBIT
1PH PADMOUNT RABBIT
3PH PADMOUNT RABBIT
RECLOSER
CUTOUT
SOLID BLADE SWITCH
GANG OPERATED SWITCH
SUBSTATION
LOOPS
NORMALLY OPEN POINT
JUNCTION VAULT
PMH
FAULTED CIRCUIT INDICATOR
1PH PADMOUNT TRANSFORMER
3PH PADMOUNT TRANSFORMER
PULLING VAULT
KING ST. D.S.
CAUTION
LAKESHORE RD.
NIAGARA BLVD.
JACKSON TRIGGS
STRATUS
SHOPPERS
CIBC
NIAGARA PARKWAY
QUEENS PARADE
Niagara On-The-Lake HYDRO
TITLE:
OLD TOWN 4KV OPERATING MAP
DRAWN BY:
T. WATSON
APPROVED BY:
C. McLEAN
SCALE:
N.T.S.
FILE NAME:
REVISION DATE:

APPENDIX D

Conditions of Service

Referenced from:

- Exhibit 1, Tab 1, Schedule 17

Niagara On-The-Lake HYDRO

CONDITIONS OF SERVICE

APRIL 30, 2003

TABLE OF CONTENTS

Section 1 – INTRODUCTION

1.1 Identification of Distributor and Service Area

Niagara-on-the-Lake Hydro Inc., referred to herein as “NOTL Hydro,” is a corporation incorporated under the laws of the Province of Ontario and a Distributor of electricity.

NOTL Hydro is licensed by the Ontario Energy Board (“OEB”) to supply electricity to Customers as described in the Transitional Distribution License issued to NOTL Hydro on April 1, 1999 by the OEB (“Distribution ED 1999-0109 License”). Additionally, there are requirements imposed on NOTL Hydro by the various codes referred to in the License and by the Electricity Act, 1998 and the Ontario Energy Board Act, 1998.

NOTL Hydro may only operate distribution facilities within its Licensed Territory as defined in its Distribution License. This service area is subject to change with the OEB's approval.

Nothing contained in this Conditions or in any contract for the supply of electricity by NOTL Hydro shall prejudice or affect any rights, privileges, or powers vested in NOTL Hydro by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

1.2 Related Codes and Governing Laws

The supply of electricity or related services by NOTL Hydro to any Customer shall be subject to various laws, regulations, and codes, including the provisions of the latest editions of the following documents:

1. Electricity Act, 1998 }part of the Energy Competition
2. Ontario Energy Board Act, 1998 }Act, 1998
3. Distribution Licence
4. Affiliate Relationships Code
5. Transmission System Code
6. Distribution System Code
7. Retail Settlement Code
8. Standard Service Supply Code

In the event of a conflict between this document and the Distribution License or regulatory codes issued by the OEB, or the Energy Competition Act, 1998 (the “Act”), the provisions of the Act, the Distribution License and associated regulatory codes shall prevail in the order of priority indicated above. If there is a conflict between a Connection Agreement with a Customer and this Conditions of Service, this Conditions of Service shall govern.

When planning and designing for electricity service, Customers and their agents must refer to all applicable provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. Without limiting to the foregoing, the work shall be conducted in accordance with the latest edition of the Ontario Occupational Health and Safety Act (OHSA), the Regulations for Construction Projects and the harmonized Electric Utility Safety Association (EUSA) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- Headings, paragraph numbers and underlining are for convenience only and do not affect the interpretation of this Conditions;
- Words referring to the singular include the plural and vice versa;
- Words referring to a gender include any gender

1.4 Amendments and Changes

The provisions of this Conditions of Service and any amendments made from time to time form part of any Contract made between NOTL Hydro and any connected Customer, Retailer, or Generator, and this Conditions of Service supercedes all previous conditions of service, oral or written, of NOTL Hydro or any of its predecessor municipal electric utility as of its effective date.

In the event of changes to this Conditions of Service, NOTL Hydro will issue a notice with the Customer’s bill. NOTL Hydro may also issue a public notice in a local newspaper and a notice on the NOTL Hydro website.

The Customer is responsible for contacting NOTL Hydro to ensure that the Customer has, or to obtain the current version of this Conditions of Service. NOTL Hydro may charge a reasonable fee for providing the Customer with a copy of this document.

1.5 Contact Information

NOTL Hydro and its agents can be contacted in person at 8 Henegan Road, Virgil, Ontario, L0S 1T0, by telephone at 905-468-4235, or by fax at 905-468-3861. Normal working hours are Monday to Friday between 8:30 a.m. and 4:30 p.m.

NOTL Hydro can also be contacted at its website at www.notlhydro.com.

In the event of an emergency, outside normal working hours, NOTL Hydro can be contacted by phone at 905-468-4235.

1.6 Customer Rights

The customer has the right to have a building connected to the distribution system if:

a) the building lies along any of the lines of NOTL Hydro’s distribution system, and;

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

Note that 'lies along' means that the building can be connected without expanding or reinforcing the distribution system.

The customer has the right to have the electric service disconnected, for the purpose of maintenance or upgrade of the service, through a written request with sufficient notice, stating both the date and time the service is to be disconnected,

The customer will be provided with one free disconnect/reconnect for "maintenance" on the existing service for each property (one service per property) each year (rolling year) without charge during regular business hours. A charge based on actual costs will otherwise apply.

The customer is responsible for maintenance and repair of their electrical service equipment. Should any component require replacement or repair, the new equipment or repair must comply with all current codes, regulations and specifications.

1.7 Distributor Rights

1.7.1 Access to Customer Property

NOTL Hydro shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998.*

1.7.2 Safety of Equipment

The Customer will comply with all aspects of the Ontario Electrical Safety Code with respect to insuring that equipment is properly identified and connected for metering and operation purposes and will take whatever steps necessary to correct any deficiencies in a timely fashion. If the Customer does not take such action within a reasonable time, NOTL Hydro may disconnect the supply of power to the Customer.

The Customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of NOTL Hydro, interfere with the proper and safe operation of NOTL Hydro's facilities or adversely affect compliance with any applicable legislation in the sole opinion of NOTL Hydro.

1.7.3 Operating Control

The Customer will provide a convenient and safe place, satisfactory to NOTL Hydro, for installing, maintaining and operating its equipment in, on, or about the Customer's premises. NOTL Hydro assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer's premises or approaches thereto, or action, omission or occurrence beyond its control, or negligence of any Persons over whom NOTL Hydro has no control.

Unless an employee or an agent of NOTL Hydro, or other Person lawfully entitled to do so, no Person shall remove, replace, alter, repair, inspect or tamper with NOTL Hydro's equipment.

Customers will be required to pay the cost of repairs or replacement of NOTL Hydro's equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

The physical location on Customer's premises at which a distributor's responsibility for operational control of distribution equipment ends is defined by the DSC as the "operational demarcation point".

1.7.4 Repairs of Defective Customer Electrical Equipment

The Customer will be required to repair or replace any equipment owned by the Customer that may affect the integrity or reliability of NOTL Hydro's distribution system. If the Customer does not take such action within a reasonable time, NOTL Hydro may disconnect the supply of power to the Customer.

1.7.5 Repairs of Customer's Physical Structures

The Customer is responsible for maintaining, repairing and replacing, in a safe condition satisfactory to NOTL Hydro, all the Customer's civil infrastructure on private property including but not limited to poles, underground conduits, cable pull vaults,, transformer rooms, transformer vaults and transformer pads that NOTL Hydro deems required to house NOTL Hydro's equipment.

1.8 Disputes or Complaints

Any dispute between consumers, customers, or retailers and NOTL Hydro shall be settled according to the dispute resolution process specified in Section 23 of the distribution Licence ED-1999-0109.

Records shall be kept of all complaints, including the complainant's name, the nature of the dispute, the resolution or escalation date, and the dispute resolution result or status.

1.8.1 Customers or Consumers

The customer or consumer shall submit their disputes to NOTL Hydro in writing via fax, e-mail, or mail.

Each inquiry shall be date stamped and recorded.

NOTL Hydro shall investigate the cause of the complaint and attempt in good faith to resolve the dispute within 10 business days of receipt.

Disputes that are expected to exceed 10 business days will be normally resolved within 30 business days of receipt. Consumers will be advised within 10 business days or receipt, of the delay and reasons thereof.

Upon Mutual agreement and under unusual circumstances, the resolution period may be extended.

Any disputes that lead to legal action against the corporation shall be referred to our legal department.

Unsolved disputes shall be referred to a third party (the OEB or a OEB approved agency) for resolution.

1.8.2 Retailers

The Retailer Service Agreement, Appendix C, Article 6, outlines how disputes between NOTL Hydro and Retailers shall be settled.

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections - Process and Timing

Under the terms of the Distribution System Code, NOTL Hydro has the obligation to either connect or to make an Offer to Connect any Customers that lie in its service area.

The Customer or its representative shall consult with NOTL Hydro concerning the availability of supply, the supply voltage, service location, metering, and any other details. These requirements are separate from and in addition to those of the Electrical Safety Authority. NOTL Hydro will confirm, in writing, the characteristics of the electric supply.

The Customer or its authorized representative shall apply for new or upgraded electric services and temporary power services in writing. The Customer is required to provide NOTL Hydro with sufficient lead-time in order to ensure:

(a) the timely provision of supply to new and upgraded premises or

(b) the availability of adequate capacity for additional loads to be connected in existing premises.

NOTL Hydro shall make every reasonable effort to respond promptly to a Customer’s request for connection. NOTL Hydro shall respond to a Customer’s written request for a Customer connection within 15 calendar days of receipt of the written request. NOTL Hydro will make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the Customer before the offer can be made.

2.1.1 Building that Lies Along

For the purpose of this Conditions "lies along" means a Customer property or parcel of land that is directly adjacent to or abuts onto the public road allowance where NOTL Hydro has distribution facilities of the appropriate voltage and capacity.

Under the terms of the Distribution System Code, NOTL Hydro has the obligation to connect (under Section 28 of the Electricity Act, 1998) a building or facility that "lies along" its distribution line, provided:

a) the building can be connected to NOTL Hydro's distribution system without an Expansion or Enhancement and,

b) the service installation meets the conditions listed in the Conditions of Service of NOTL Hydro.

The location of the Customer's service entrance equipment will be subject to the approval of NOTL Hydro and the Electrical Safety Authority.

2.1.2 Expansions / Offer to Connect

Under the terms of the Distribution System Code, NOTL Hydro is required to make an "Offer to Connect" if, in order to connect a Customer, NOTL Hydro must construct new distribution system facilities or increase the capacity of existing distribution facilities (i.e. an "Expansion" of its system).

Customers may seek an alternative bid for construction of new distribution facilities when the construction does not involve existing circuits.

In the offer to connect NOTL Hydro will detail the scope of the work, what portion is subject to alternative bid and the requirements if a customer proceeds with an alternate bid to undertake the work related to the expansion. NOTL Hydro will continue to be responsible for the maintenance and reliability of the system and as such will carry out planning, preliminary design and verification that the installed system meets NOTL Hydro standards.

The customer is required to pay the cost of system expansion or reinforcement that is required to supply their loads. A credit will be allowed which will offset the cost in whole or in part based on an economic evaluation (for details see Appendix B) of the DSC. An economic evaluation based on NOTL Hydro's forecast of the customer's load, will determine whether the future net revenue of NOTL Hydro will pay for the capital and on-going maintenance costs of the expansion project. The cost will include both the expansion of the system attributable directly to the customer's project as well the cost for the general enhancement of the system.

NOTL Hydro will perform an economic evaluation to determine whether the future revenue from the Customer will pay for the capital and on-going maintenance costs of the Expansion project (refer to methodology and assumptions in the DSC Code –Appendix B). At the discretion of NOTL Hydro, the capital costs for the Expansion may include incremental costs associated with the full use of NOTL Hydro's existing spare facilities or equipment, which may result in an adverse impact to future Customers. The economic evaluation will be based on the Customer's proposed load ("Estimated Incremental Demand").

NOTL Hydro may charge a Customer that chooses to pursue an alternative bid any costs incurred by NOTL Hydro associated with the expansion project, including but not limited to the following:

- costs for additional design, engineering, or installation of facilities required to complete the project that were made in addition to the original Offer to Connect
- costs for inspection or approval of the work performed by the contractor hired by the Customer.
- costs for connection of the expansion project to the existing NOTL Hydro Distribution System

2.1.2.1 Security Deposit

To keep NOTL Hydro harmless in respect of the expansion fees and operating and maintenance costs for an Expansion, an Offer to Connect may require Customers to provide a security deposit to cover the difference between the actual expansion fees and the amount of the capital contribution paid by the Customer, in accordance with NOTL Hydro's economic evaluation of the Expansion.

The security deposit must be in the form of (i) cash or cheque or (ii) an irrevocable commercial letter of credit issued by a financial institution acceptable to NOTL Hydro. NOTL Hydro will not accept third party guarantees. This security deposit is in addition to any other charges or deposits that may be required by NOTL Hydro and is to be provided **prior to** the commencement of any expansion work.

2.1.3 Connection Denial

NOTL Hydro is not obligated to connect a building within its service area if the connection would result in any of the following:

- Contravention of existing laws of Canada and the Province of Ontario
- Violations of conditions in NOTL Hydro's Licence
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend to serve
- Adverse affect on the reliability or safety of the distribution system
- Public safety reasons or imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system
- A material decrease in the efficiency of the distributor's distribution system
- A materially adverse effect on the quality of distribution services received by an existing connection
- Discriminatory access to distribution services

- If the person requesting the connection owes NOTL Hydro money for Distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor
- If an electrical connection to NOTL Hydro's distribution system does not meet NOTL Hydro's design requirements
- Any other conditions documented in NOTL Hydro's Conditions of Service document.

If NOTL Hydro refuses to connect a building in its service area that lies along one of its distribution lines, NOTL Hydro shall inform the person requesting the connection of the reasons for the denial, and where NOTL Hydro is able to provide a remedy, make an offer to connect. If NOTL Hydro is not capable of resolving the issue, it is the responsibility of the Customer to do so before a connection can be made.

2.1.4 Inspections Before Connections

All Customer electrical installations shall be inspected and approved by the Electrical Safety Authority and must also meet NOTL Hydro's requirements. NOTL Hydro requires notification from the Electrical Safety Authority of this approval prior to the energization of a Customer's supply of electricity. Services that have been disconnected for a period of six months or longer must also be re-inspected and approved by the Electrical Safety Authority, prior to reconnection.

Temporary services, typically used for construction purposes and for a period of twelve months or less, must be approved by the Electrical Safety Authority and must be re-inspected should the period of use exceed twelve months.

Customer-owned substations must be inspected by both the Electrical Safety Authority and NOTL Hydro.

Transformer vaults and bases shall be inspected and approved by NOTL Hydro prior to the installation of NOTL Hydro's equipment.

Connection to existing duct banks or vaults shall be done only by a contractor approved by NOTL Hydro. All work done on existing NOTL Hydro's plant must be authorized by NOTL Hydro and carried out in accordance with all applicable safety acts and regulations.

Provision for metering shall be inspected and approved by NOTL Hydro prior to energization.

2.1.5 Relocation of Plant

When requested to relocate distribution plant, NOTL Hydro will exercise its rights and discharge its obligations in accordance with existing acts, by-laws and regulations including the *Public Service Works on Highways Act*, formal agreements, easements and law. In the absence of existing agreements, NOTL Hydro is not obligated to relocate the plant. However, NOTL Hydro shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner will include a response to the requesting party that explains the feasibility or unfeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

In the course of maintaining and enhancing NOTL Hydro's distribution plant NOTL Hydro may need to relocate distribution plant that is owned by NOTL Hydro. Costs associated with such relocation(s) shall be borne by NOTL Hydro, except that, in accordance with Section 3.2hereof, if the Customer requests that such maintenance or construction activities be done outside NOTL Hydro's normal working hours, the Customer shall pay for 100% of costs incurred by NOTL Hydro as a result thereof.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, NOTL Hydro has the right to place supply facilities on private property and to have easements registered against title to the property. Easements are required where facilities serve customers other than property where the facilities are located and/or where NOTL Hydro deems it necessary.

The Customer will prepare at its own cost any required reference plan and easement documents to the satisfaction of NOTL Hydro. Four copies of the deposited reference plan and easement documents must be supplied to NOTL Hydro.

2.1.7 Contracts

2.1.7.1 Contract for New or Modified Electricity Service

NOTL Hydro shall only connect a Building for a new or modified supply of electricity upon receipt by NOTL Hydro of a completed and signed contract for service in a form acceptable to NOTL Hydro, payment to NOTL Hydro of any applicable connection charge, and an inspection and approval by the Electrical Safety Authority of the electrical equipment for the new service.

2.1.7.2 Implied Contract

In all cases, notwithstanding the absence of a written contract, NOTL Hydro has an implied contract with any Customer that is connected to NOTL Hydro’s distribution system and receives distribution services from NOTL Hydro. The terms of the implied contract are embedded in NOTL Hydro’s Conditions of Service, the Rate Handbook, NOTL Hydro’s rate schedules, NOTL Hydro’s licence, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code, all as amended from time to time.

Any Person(s) who take or use electricity delivered and/or supplied by NOTL Hydro shall be liable for payment for such electricity. Any implied contract for the supply of electricity by NOTL Hydro shall be binding upon the heirs, administrators, executors, successors or assigns of the Person(s) who took and/or used electricity supplied by NOTL Hydro. In the absence of a contract for electricity with a tenant, or in the event the electricity is used by a Person(s) unknown to NOTL Hydro, then the cost for electricity consumed by such Person(s) is due and payable by the owner(s) of such property.

2.1.7.3 Special Contracts

Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- construction sites
- mobile facilities
- non-permanent structures
- special occasions, etc.
- generation

2.1.7.4 Connection Agreements

NOTL Hydro may require a Customer to enter into a Connection Agreement in a form acceptable to NOTL Hydro. Until such time as the Customer executes such a Connection Agreement with NOTL Hydro, the Customer shall be deemed to have accepted and agreed to be bound by all of the terms of the NOTL Hydro Connection Agreement.

2.1.7.5 Payment by Building Owner

The owner of a Building is responsible for paying for the supply of electricity by NOTL Hydro to the owner's Building except for any supply of electricity to the Building by NOTL Hydro in accordance with a request for electricity by an occupant(s) of the Building. A Building owner wishing to terminate the supply of electricity to its Building must notify NOTL Hydro in writing. Until NOTL Hydro receives such written notice from the Building owner, the Building owner or the occupant(s), as applicable, shall be responsible for payment to NOTL Hydro for the supply of electricity to such Building. NOTL Hydro may refuse to terminate the supply of electricity to an owner's Building when there are occupant(s) in the Building who have signed a contract for electric service and energy or during certain periods of the winter.

2.1.7.6 Opening and Closing of Accounts

A Consumer who wishes to open or close an account for the supply of electricity by NOTL Hydro shall contact NOTL Hydro by phone, by written request (including requests submitted by facsimile), or other means acceptable to NOTL Hydro.

The Consumer shall be responsible for payment to NOTL Hydro for the supply of electricity to the property up to the date NOTL Hydro is notified of the termination of the account.

2.2 Disconnection

NOTL Hydro reserves the right to disconnect the supply of electrical energy for causes not limited to:

- Contravention of the laws of Canada or the Province of Ontario.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection
- Discriminatory access to distribution services
- Inability of NOTL Hydro to perform planned inspections and maintenance.
- Failure of the Consumer or Customer to comply with a directive of NOTL Hydro that NOTL Hydro makes for purposes of meeting its licence obligations.
- Overdue amounts payable to NOTL Hydro for the distribution or retail of electricity
- Electrical disturbance propagation caused by Customer equipment that are not corrected in a timely fashion
- Any other conditions identified in this Conditions of Service document

NOTL Hydro may disconnect the supply of electricity to a Customer without notice in accordance with a court order, or for emergency, safety or system reliability reasons.

2.2.1 Disconnection For Non-Payment of Overdue Accounts

Immediately following the due date, steps will be taken to collect the full amount of the bill. NOTL Hydro will implement our credit and collections policy (refer to Appendix 1-Credit & Collection Policy) as it refers to disconnect and reconnect policies. Such discontinuance of service does not relieve the Customer of the liability for arrears or minimum bills for the balance for the term of contract, nor shall NOTL Hydro be liable for any damage to the Customer’s premises resulting from such discontinuance of service. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing. Notwithstanding the foregoing, NOTL Hydro shall not shut off the distribution of electricity to a property for non-payment as set forth above during such periods as may be prescribed by regulations under the *Electricity Act, 1998*.

Upon discovery that a hazardous condition or disturbance propagation (feedback) exists, NOTL Hydro will notify the Customer to rectify the condition at once. In case the Customer fails to make satisfactory arrangements to remedy the condition within seven calendar days after a disconnect notice has been given to the Customer, the service may be disconnected and not restored until satisfactory arrangements to remedy the condition have been made.

NOTL Hydro shall not be liable for any damage to the Customer's premises resulting from such discontinuance of service. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing.

Upon receipt of a Disconnection request by the Customer, NOTL Hydro will disconnect and/or remove NOTL Hydro's assets.

2.2.2 Unauthorized Energy Use

NOTL Hydro reserves the right to disconnect the supply of electrical energy to a Customer for causes not limited to energy diversion, fraud or abuse on the part of the Customer. Such service may not be reconnected until the Customer rectifies the condition and provides full payment to NOTL Hydro including all costs incurred by NOTL Hydro arising from unauthorized energy use, including inspections, administrative and legal costs, repair costs, and the cost of disconnection and reconnection.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guaranty of Supply

NOTL Hydro will endeavour to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Consumer by reason of any failure in respect thereof.

Customers requiring a higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities. Customers may require special protective equipment at their premises to minimize the effect of momentary power interruptions.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributor's supply.

During an emergency, NOTL Hydro may interrupt supply to a Consumer in response to a shortage of supply, or to effect repairs on the distribution system, or while repairs are being made to Consumer-owned equipment.

NOTL Hydro shall have rights to access to a property in accordance with section 40 of the *Electricity Act, 1998* and any successor acts thereto.

To assist with distribution system outages or emergency response, NOTL Hydro may require a Consumer to provide NOTL Hydro with emergency access to Consumer-owned distribution equipment that normally is operated by NOTL Hydro or NOTL Hydro-owned equipment on Consumer's property.

2.3.2 Power Quality

2.3.2.1 Power Quality Testing

Where a Consumer provides evidence or data indicating that a power quality or EMI problem may be originating from NOTL Hydro distribution system, NOTL Hydro will perform investigative analysis to attempt to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data, trend analysis, and power quality monitoring.

Upon determination of the cause resulting in the power quality concern, where it is deemed a system delivery issue and where industry standards are not met, NOTL Hydro will recommend and/or take appropriate mitigation measures. NOTL Hydro will take appropriate actions to control power disturbances found to be detrimental to the Consumers. If NOTL Hydro is unable to correct the problem without adversely affecting other NOTL Hydro Consumers, then it is not obligated to make the corrections. NOTL Hydro will use appropriate industry standards (such as IEC or IEEE standards) and good utility practice as a guideline. If the problem lies on the Consumer side of the system, NOTL Hydro may seek reimbursement from the Consumer for the costs incurred in its investigation.

2.3.2.2 Prevention of Voltage Distortion on Distribution

Consumers having non-linear load shall not be connected to NOTL Hydro's distribution system unless power quality is maintained by implementing proper corrective measures such as installing proper filters, and/or grounding. Further, to ensure the distribution system is not adversely affected, power electronics equipment installed must comply with IEEE Standard 519-1992. The limit on individual harmonic distortion is 3%, while the limit on total harmonic distortion is 5%.

2.3.2.3 Obligation to Help in the Investigation

If NOTL Hydro determines the Consumer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on NOTL Hydro's distribution system, the Consumer is obligated to help NOTL Hydro by providing required equipment information, relevant data and necessary access for monitoring the equipment.

2.3.2.4 Timely Correction of Deficiencies

If an undesirable system disturbance is being caused by Consumer's equipment, the Consumer will be required to cease operation of the equipment until satisfactory remedial action has been taken by the Consumer at the Consumer's cost. If the Consumer does not take such action within a reasonable time, NOTL Hydro may disconnect the supply of power to the Consumer.

2.3.2.5 Notification for Interruptions

Although it is NOTL Hydro’s policy to minimize inconvenience to Consumers, it is necessary to occasionally interrupt a Consumer 's supply to allow work on the electrical system. NOTL Hydro will endeavor to provide such Consumers with reasonable notice of planned power interruptions. However, interruption times may change due to inclement weather or other unforeseen circumstances. NOTL Hydro shall not be liable in any manner to such Consumers for failure to provide such notice of planned power interruptions or for any change to the schedule for planned power interruptions. Notice may not be given where work is of an emergency nature involving the possibility of injury to persons or damage to property or equipment.

However, during an emergency, NOTL Hydro may interrupt supply to a Consumer in response to a shortage of supply or to effect repairs on NOTL Hydro’s distribution system or while repairs are being made to Customer-owned equipment

2.3.2.6 Notification to Consumers on Life Support

Consumers who require an uninterrupted source of power for life support equipment must provide their own equipment for these purposes. Consumers with life support system are encouraged to inform NOTL Hydro of their medical needs and their available backup power. These Consumers are responsible for ensuring that the information they provide NOTL Hydro is accurate and up-to-date.

2.3.2.7 Emergency Interruptions for Safety

NOTL Hydro will endeavour to notify Consumers prior to interrupting the supply to any service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to NOTL Hydro or the public, service may be interrupted without notice.

2.3.2.8 Emergency Service (Trouble Calls)

NOTL Hydro will exercise reasonable diligence and care to deliver a continuous supply of electrical energy to the Consumer. However, NOTL Hydro cannot guarantee a supply that is free from interruption.

When power is interrupted, the Consumer should first ensure that failure is not due to blowing of fuses within the installation. If, on examination, it appears that NOTL Hydro’s main source of supply has failed, the Consumer should report these conditions at once to NOTL Hydro by calling 905-468-4235.

NOTL Hydro will initiate restoration efforts as rapidly as practicable.

2.3.2.9 Outage Reporting

Depending on the outage, duration and the number of Consumers affected, NOTL Hydro may issue a news release to advise the general public of the outage. In turn, news radio stations may call for information on a 24-hour basis when they hear of an outage.

2.3.3 Electrical Disturbances

NOTL Hydro shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in Section 2.3.5 of this Conditions.

Voltage fluctuations and other disturbances can cause flickering of lights and other serious difficulties for Consumers connected to NOTL Hydro's distribution system. Customers must ensure that their equipment does not cause disturbances such as harmonics and spikes that might interfere with the operation of adjacent Consumer equipment. Equipment that may cause disturbances includes large motors, welders and variable speed drives, etc. In planning the installation of such equipment, the Customer must consult with NOTL Hydro.

Customers who may require an uninterrupted source of power supply or a supply completely free from fluctuation and disturbance must provide their own power conditioning equipment for these purposes.

2.3.4 Standard Voltage Offerings

2.3.4.1 Primary Voltage

The primary voltage to be used will be determined by NOTL Hydro for both NOTL Hydro-owned and Customer-owned transformation. Depending on what voltage of the plant that "lies along", the preferred primary voltage will be at 27.6/ 16 kV grounded wye, three phase, four-wire system.

2.3.4.2 Supply Voltage Offerings

Depending on the type of distribution plant that "lies along", the preferred secondary voltage may be:

120/240V, single phase, or

120/208V, three phase, 4 wire

347/600V, three phase, 4 wire.

2.3.5 Voltage Guidelines

NOTL Hydro maintains service voltage at the Customer's service entrance within the guidelines of C.S.A. Standard CAN3-C235-87 (latest edition) which allows variations from nominal voltage of,

5% for Normal Operating Conditions
8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action should be taken on a planned and programmed basis, but not necessarily on an emergency basis. Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action should be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

NOTL Hydro shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter or host Distributor. NOTL Hydro shall not be liable for any delay or failure in the performance of any of its obligations under this Conditions of Supply due to any events or causes beyond the reasonable control of NOTL Hydro, including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes ("Force Majeure").

2.3.6 Back-up Generators

Customers with portable or permanently connected generation capability used for emergency back-up shall comply with all applicable criteria of the Ontario Electrical Safety Code. In particular, the Customer shall ensure that Customer's emergency generation does not parallel with NOTL Hydro's system without a proper interface protection and does not adversely affect NOTL Hydro's distribution system.

Customers with permanently connected emergency generation equipment shall notify NOTL Hydro regarding the presence of such equipment.

2.3.7 Metering

NOTL Hydro will supply, install, own, and maintain all meters, instrument transformers, ancillary devices, and secondary wiring required for revenue metering.

Additional metering requirements are listed in the Distribution System Code. Metered Market Participants in the Independent Electricity Market Operator ("IMO") administered wholesale market must meet or exceed all IMO metering requirements.

2.3.7.1 General

NOTL Hydro will typically install metering equipment at the Customer supply voltage. The Customer must provide a convenient and safe location satisfactory to NOTL Hydro, for the installation of meters, wires and ancillary equipment. Meters for new or upgraded residential services will be mounted outdoors on a meter socket approved by NOTL Hydro.

No person, except those authorized by NOTL Hydro, may remove, connect, or otherwise interfere with meters, wires, or ancillary equipment.

The Customer will be responsible for the care and safekeeping of NOTL Hydro meters, wires and ancillary equipment on the Customer's premises. If any NOTL Hydro equipment installed on Customer premises is damaged, destroyed, or lost other than by ordinary wear and tear, tempest or lightning, the Customer will be liable to pay to NOTL Hydro the replacement cost including labour of such equipment, or at the option of NOTL Hydro, the cost of repairing the same.

The location allocated by the owner for NOTL Hydro metering shall provide direct access for NOTL Hydro staff and shall be subject to satisfactory environmental conditions, some of which are:

- Maintain a safe and adequate working space in front of equipment, not less than 1.2 metres (48") and a minimum ceiling height of 2.1 metres (84")
- Maintain an unobstructed working space in front of equipment, free from, or protected against, the adverse effects of moving machinery, vibration, dust, moisture or fumes

Where NOTL Hydro deems self-contained meters to be in a hazardous location, the Customer shall provide a meter cabinet or protective housing.

Any compartments, cabinets, boxes, sockets, or other work-space provided for the installation of NOTL Hydro's metering equipment shall be for the exclusive use of NOTL Hydro. No equipment, other than that provided and installed by NOTL Hydro, may be installed in any part of the NOTL Hydro metering work-space.

2.3.7.1.1 Multi-Unit Buildings

NOTL Hydro will provide the "house meter" at no cost to the customer. Additional meters will be provided by NOTL Hydro at the customers expense. The Customer shall permanently and legibly identify each metered service with respect to its specific address, including unit or apartment number. The identification shall be applied to all service switches, circuit breakers, meter cabinets, and meter mounting devices.

2.3.7.2 Current Transformer Boxes

Where instrument transformers are incorporated in low voltage switchgear, the size of the chamber and number of instrument transformers shall specified by NOTL Hydro.. A separate meter cabinet must be supplied and installed by the Customer and located to the satisfaction of NOTL Hydro. The cabinet and the compartment will be connected by an empty 1½ inch conduit, the length of which shall not exceed 20 m, and which shall include a maximum of three 90° bends. The conduit will be provided for the exclusive use of NOTL Hydro. No fittings with removable covers are permitted.

The meter cabinet shall be grounded by a minimum #6 copper grounding conductor, not installed in the above conduit. The Customer shall install a strong nylon or polyrope pull line in the conduit, with an excess of 1500 mm loop left at each end.

The final layout and arrangements of components must be approved by NOTL Hydro prior to fabrication of equipment.

2.3.7.3 Interval Metering

Interval meters will be installed for all new or upgraded services where the peak demand is forecast to be 500 kW or greater, or for any Customer wishing to participate in the spot market pass-through pricing. Prior to the installation of an interval meter, the Customer must provide a ½ inch conduit from their telephone room to the meter cabinet. NOTL Hydro will arrange for the installation of a telephone line, terminated in the meter cabinet for the exclusive use of NOTL Hydro to retrieve interval meter data. The Customer will be responsible for the installation and ongoing monthly costs of operating the phone line. The phone line will be direct dial voice quality, active 24 hours per day, and energized prior to meter installation.

The Customer will be responsible for monthly costs of meter interrogation.

Other Customers that request interval metering shall compensate NOTL Hydro for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and reverification of the meter, installation, administration and ongoing provision of communication line or communication link with the Customer' s meter, and cost of metering made redundant by the Customer requesting interval metering.

2.3.7.4 Meter Reading

The Customer must provide or arrange free, safe and unobstructed access during regular business hours to any authorized representative of NOTL Hydro for the purpose of meter reading, meter changing, or meter inspection. Where premises are closed during NOTL Hydro’s normal business hours, the Customer must, on reasonable notice, arrange such access at a mutually convenient time. In the case of a customer missing two arranged appointments for the purpose of a meter read, the third or subsequent attempts will be charged to the customer based on actual internal costs.

2.3.7.5 Final Meter Reading

When a service is no longer required, the Customer shall provide sufficient notice of the date the service is to be discontinued so that NOTL Hydro can obtain a final meter reading as close as possible to the final reading date. The

Customer shall provide access to NOTL Hydro or its agents for this purpose. If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. NOTL Hydro's revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, NOTL Hydro will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by NOTL Hydro, due regard being given to any change in the characteristics of the installation and/or the demand. If Measurement Canada, Industry Canada determines that the Customer was overcharged, NOTL Hydro will reimburse the Customer for the amount incorrectly billed.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. NOTL Hydro will correct the bills for that period in accordance with the regulations under the Electricity and Gas Inspection Act.

2.3.7.7 Meter Dispute Testing

Metering inaccuracy is an extremely rare occurrence. Most billing inquiries can be resolved between the Customer and NOTL Hydro without resorting to the meter dispute test.

Either NOTL Hydro or the Customer may request the service of Measurement Canada to resolve a dispute. If the Customer initiates the dispute, NOTL Hydro will charge the Customer a meter dispute fee if the meter is found to be accurate and Measurement Canada rules in favor of the utility.

NOTL Hydro will follow the Billing and Customer Service Policies regarding dispute meter tests and agent’s fee (refer to Appendix 2).

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for distribution services are made as set out in the Schedule of Rates available from NOTL Hydro. Notice of Rate revisions shall be published in major local newspapers. Information about changes will also be mailed to all

Customers with the first billing issued at revised rates.

2.4.1.1 Customers Switching to Retailer

There are no physical service connection differences between Standard Service Supply (SSS) Customers and third party retailers' Customers. Both Customer energy supplies are delivered through the local Distributor with the same distribution requirements. Therefore, all service connection requirements applicable to the SSS Customers are applicable to third party retailers' Customers.

2.4.1.2 Supply Deposits & Agreements

Where an owner proposes the development of premises that require NOTL Hydro to place orders for equipment for a specific project and before actual construction begins, the owner is required to sign the necessary Supply Agreement and furnish a suitable deposit before such equipment is ordered by NOTL Hydro.

An irrevocable (standby) letter of credit or a letter of guarantee from a chartered bank, trust company or credit union is acceptable in lieu of a cash deposit.

2.4.2 Energy Supply

2.4.2.1 Standard Service Supply (SSS)

All existing NOTL Hydro Customers are Standard Service Supply (SSS) Customers until NOTL Hydro is informed of their switch to a competitive electricity supplier. The Service Transfer Request (STR) must be made by the Customer or the Customer's authorized retailer.

2.4.2.2 Retailer Supply

Customers transferring from Standard Service Supply (SSS) to a retailer shall comply with the Service Transfer Request (STR) requirements as outlined in sections 10.5 through 10.5.6 of the Retail Settlement Code.

All requests shall be submitted as electronic file and transmitted through EBT Express. Service Transfer Request (STR) shall contain information as set out in section 10.3 of the Retail Settlement Code.

If the information is incomplete, NOTL Hydro shall notify the retailer or Customer about the specific deficiencies and await a reply before proceeding to process the transfer.

2.4.3 Deposits

Whenever required by NOTL Hydro, including, but not limited to, as a condition of supplying or continuing to supply Distribution Services, Consumers shall provide and maintain security in an amount outlined in the NOTL Hydro's Credit and Collection Policy (refer to Appendix 1)

2.4.4 Billing

NOTL Hydro may, at its option, render bills to its Customers on either a monthly, every two months, quarterly or annual basis. Bills for the use of electrical energy may be based on either a metered rate or a flat rate, as determined by NOTL Hydro.

The Customer may dispute charges shown on the Customer's bill or other matters by contacting and advising NOTL Hydro of the reason for the dispute. NOTL Hydro will promptly investigate all disputes and advise the Customer of the results.

2.4.5 Payments and Overdue Account Interest Charges

Bills are rendered for energy services provided to the Customer. Bills are payable in full by the due date; otherwise, overdue interest charge will apply. Where a partial payment has been made by the Customer on or before the due date, the interest charge will apply only to the amount of the bill outstanding at the due date, exclusive of arrears from previous billings.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

NOTL Hydro shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge will apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

Customers will be required to pay special charges, on request, which may arise from a variety of conditions such as:

Transfer Charge. A change of occupancy charge will apply to all accounts taken over by a new Customer.

Collection Charge. It is sometimes necessary, for the Customer's convenience, for a NOTL Hydro employee to visit a Customer's premises to collect payment for an account. There will be a charge for this service.

Reconnection Charge. A Consumer disconnected for non-payment shall be required to pay a reconnection fee.

2.5 Customer Information

A third party who is not a retailer may request historical usage information with the written authorization of the Customer to provide their historical usage information. NOTL Hydro will provide information appropriate for operational purposes that has been aggregated sufficiently, such that an individual's Consumer information cannot reasonably be identified, at no charge to another distributor, a transmitter, the IMO or the OEB. NOTL Hydro may charge a fee that has been approved by the OEB for all other requests for aggregated information.

At the request of a Consumer, NOTL Hydro will provide a list of retailers who have Service Agreements in effect within its distribution service area. The list will inform the Consumer that an alternative retailer does not have to be chosen in order to ensure that the Consumer receives electricity and the terms of service that are available under Standard Supply Service.

Upon receiving an inquiry from a Consumer connected to its distribution system, NOTL Hydro will either respond to the inquiry if it deals with its own distribution services or provide the Consumer with contact information for the entity responsible for the item of inquiry, in accordance with chapter 7 of the Retail Settlement Code.

An embedded distributor that receives electricity from NOTL Hydro shall provide load forecasts or any other information related to the embedded distributor’s system load to NOTL Hydro, as determined and required by NOTL Hydro. A Distributor shall not require any information from another Distributor unless it is required for the safe and reliable operation of either Distributor’s distribution system or to meet a Distributor’s licence obligations.

Section 3-CUSTOMER CLASS SPECIFIC

3.1 Residential Services

This section refers to the supply of electrical energy to detached, semi detached or townhouse dwelling units.

The maximum service size is typically limited to 120 / 240 volt, 200 amp, 1 phase.

Service size of 120 / 240 volt, 400 amp, 1 phase may be available subject to technical constraints.

Residential services are provided overhead with the exception of the following:

1. Designated underground areas; Refer to Appendix 3
2. Areas defined by subdivision or development agreements.
3. Customer request for U/G service connection.

Refer to Appendix 4 Table 1 for Point of Demarcation, Standard Allowance and Connection Fees for residential services.

3.1.1 Overhead Services

In addition to the requirements of the Ontario Electrical Safety Code (latest edition), the following conditions shall apply:

(i) A clevis type insulator is to be supplied and installed by the Customer.

(ii) This point of attachment device must be located:
(a) Not less than 4.5 metres (15 feet) nor greater than 5.5 metres (18 feet) above grade (to facilitate proper ladder handling techniques).
(b) Between 150 millimetres and 300 millimetres (6-12 inches) below the service head.
(c) Within 914 millimetres (3 feet) of the face of the building.

(iii) Clearance must be provided and maintained between utility conductors and finished grade of a least 4.5 meters (15 feet).

A minimum horizontal clearance of 1.0 metres (39 inches) must be provided from utility conductors and any second storey windows.

(iv) A meter socket of an approved manufacturer shall be provided. The Customer should contact NOTL Hydro to confirm details.

(v) Clear unobstructed access must be maintained to and in front of the meter location.

(vi) Service locations requiring access to adjacent properties (mutual drives, narrow side set-backs, etc.) will require the completion of an easement or written consent from the property owner(s) involved.

(vii) The approved meter base shall be mounted directly below the service mast such that the midpoint of the meter is 1.73 m (± 100 mm) above finished grade within 914 mm of the face of the building (in front of any existing or proposed fence), unless otherwise approved by NOTL Hydro.

3.1.2 Underground Services-Designated Areas

The standard U/G service is 120/240 volt, 200 amp, 1 phase.

NOTL Hydro will typically install and maintain service conductors for the standard service. NOTL Hydro reserves the right to require the customer to install the U/G cable due to site conditions.

In designated areas, all new service connections will be by U/G service cable. The customer will be required to pay 100 % of the connection and installation costs for the U/G service less the standard allowance for an O/H service. A minimum charge will apply.
Customers in designated U/G areas that make application to upgrade or alter existing O/H service connections are required to convert to an U/G cable connection. The customer will be required to pay 100% of the connection and installation costs with no minimum charge.

Upon application for a new or upgraded service, NOTL Hydro will complete a customer service layout indicating the connection point, conductor route and cost of connection and installation.

The cost of installation will be calculated from the connection point to the meter base location.

NOTL Hydro will establish the connection point, trench route, and meter base location.

A 200 amp rated meter base will be supplied and installed by the customer. The meter base shall be located no more than 1.5 m from the front corner of the building.

3.1.3 Underground Services-Customer Requested

The standard U/G service is 120 /240 volt, 200 amp, 1 phase.

NOTL Hydro will typically install and maintain service conductors for the standard service. NOTL Hydro reserves the right to require the customer to install the U/G cable due to site conditions.

In areas other than those designated as U/G service areas, customers may request new or upgraded service connection by U/G service cable. The customer will be required to pay 100% of the connection and installation costs for the U/G service less the standard allowance for an O/H service. A minimum charge will apply.

Upon application for a new or upgraded service, NOTL Hydro will complete a customer service layout indicating the connection point, conductor route and cost of connection and installation.

The cost of installation will be calculated from the connection point to the meter base location.

NOTL Hydro will establish the connection point, trench route, and meter base location.

A 200 amp rated meter base will be supplied and installed by the customer. The meter base shall be located no more than 1.5 m from the front corner of the building.

3.1.4 Underground Services-Subdivisions

The standard U/G service is 120 / 240 volt, 200 amp, 1 phase.

NOTL Hydro will typically install and maintain service conductors for the standard service. NOTL Hydro reserves the right to require the customer to install the U/G cable due to site conditions.
In areas developed under plan of subdivision, new services connections are provided by U/G cable.

The customer will be required to pay 100% of the connection and installation costs for the U/G service. A minimum charge will apply.

Upon application for a new or upgraded service, NOTL Hydro will complete a customer service layout indicating the connection point, conductor route and cost of connection and installation.

The cost of installation will be calculated from the connection point to the meter base location.

NOTL Hydro will establish the connection point, trench route, and meter base location.

A 200 amp rated meter base will be supplied and installed by the customer. The meter base shall be located no more than 1.5 m from the front corner of the building.

3.2 General Service Requirements

a) The Customer shall supply the following to NOTL Hydro well in advance of installation commencement:
- Required in-service date
- Proposed Service Entrance equipment's Rated Capacity (Amperes) and Voltage rating and metering requirements
- Proposed Total Load details in kVA and/or kW (Winter and Summer)
- Locations of other services, gas, telephone, water and cable TV.
- Details respecting heating equipment, air-conditioners, motor starting current limitation and any appliances which demand a high consumption of electrical energy
- Survey plan and site plan indicating the proposed location of the service entrance equipment with respect to public rights-of-way and lot lines.
- Electrical, architectural and/or mechanical drawings as required by NOTL Hydro.

c) The Customer shall construct or install all civil infrastructure (including but not limited to poles, UG conduits, cable pull vaults, transformer room/vault/pad) on private property, that is deemed required by NOTL Hydro. All civil infrastructure are to be in accordance with NOTL Hydro's current standards, practices, specifications, this Conditions of Service and the O.E.S.C.

d) NOTL Hydro will undertake the necessary programs to maintain and enhance its distribution plant at its expense, as part of its planned activities during normal business hours, Monday to Friday. Where a Customer request such planned activities to be done outside normal working hours, then the Customer shall pay 100% of the costs. In the event that services or facilities to a Customer need to be restored as a result of these construction or maintenance activities by NOTL Hydro, they will be restored to an equivalent condition. In addition NOTL Hydro will carry out the necessary construction and electrical work to maintain existing supplies by providing standard overhead or underground supply services to Customers affected by NOTL Hydro's construction activities. If a Customer requests special construction beyond the normal NOTL Hydro standard installation in accordance with the program, the Customer shall pay the additional cost, including engineering and administration fees.

e) The owner may be required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements and provide clear working space in accordance with the Ontario Electrical Safety Code.

f) Access doors, panels, slabs and vents shall be kept free from obstructing objects. The Customer will provide unimpeded and safe access to NOTL Hydro at all times for the purpose of installing, removing, maintaining, operating or changing transformers and associated equipment.

g) The electrical room must be located to provide safe access from the outside or main hallway, and not from an adjoining room, so that it is readily accessible to NOTL Hydro's employees and agents at all hours to permit meter reading and to maintain electric supply.

h) The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code and shall be located indoors.

i) The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault circuit shall be supplied from a panel located and clearly identified in the electrical room.

3.2.1 General Service in Designated Areas

In designated U/G area, new upgraded General service connections will be by U/G service cable. Transformation, switchgear and any other facility required will be of the padmount type. The customer may be required to provide a suitable location on their property for padmounted equipment. Refer to Appendix 3 for Designated Areas.

3.2.2 Underground Service Requirements

The Customer shall construct or install all civil infrastructure (including but not limited to poles, UG conduits, cable chambers, cable pull rooms, transformer room/vault/pad) on private property that is deemed required by NOTL Hydro. All civil infrastructure are to be in accordance with NOTL Hydro's current standards, practices, specifications this Conditions of Service and the O.E.S.C. The Customer is responsible to maintain all its structural and mechanical facilities on private property in a safe condition satisfactory to NOTL Hydro.

The trench route must be approved by NOTL Hydro. Any deviation from this route must also be approved by NOTL Hydro. The Customer will be responsible for NOTL Hydro's costs associated with re-design and inspection services due to changes or deviations initiated by the Customer or its agents or any other body having jurisdiction.

It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies (including the local Distribution company) before digging.

3.2.3 Temporary Services (other than Residential)

A temporary service is a normally metered service provided for construction purposes or special events. Temporary services can be supplied overhead or underground. The Customer will be responsible for all associated costs for **the installation and removal** of equipment required for a temporary service to NOTL Hydro's point of supply. Temporary services may be provided for a period of no more than 12 months. Temporary services must be renewed thereafter if an extension is required and the equipment for such temporary service must be reinspected at the end of the 12-month period. Refer to Appendix 4-Table 4.

Subject to the requirements of NOTL Hydro, supply will be connected after receipt of a 'Connection Authorization' from the Electrical Safety Authority, a signed contract and a deposit from the Customer.

Where meter bases are required, they must be approved by NOTL Hydro and shall be securely mounted on minimum 152 mm diameter poles (or alternative if approved by NOTL Hydro) so that the midpoint of the meter is 1.73 m (± 100 mm) from finished grade.

In the case of temporary overhead services, the Customer shall leave 760 mm of cable at the masthead for connection purposes.

In the case of temporary underground services, the Customer's cable shall extend to NOTL Hydro's point of supply.

3.3 General Services Less Than 50 kW

This section applies to smaller commercial, industrial and institutional developments supplied from the municipal road right of way, generally at secondary voltages.

The customer will be required to pay 100% of the cost of service connection and installation.

Refer to Appendix 4-Table 2 for Point of Demarcation, Standard Allowance and Connection Fees for General services.

3.4 General Service (Above 50 kW)

All non-residential Customers with an average peak demand between 50 kW and 999 kW over the past twelve months are to be classified as General Services above 50 kW. For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer.

This section applies to commercial industrial and institutional developments, where typically a primary voltage service is required.

Where the size of the Customer's electrical service warrants, the Customer will be required to provide facilities on its property and an easement as required (i.e. on the premises to be served), acceptable to NOTL Hydro, to house the necessary transformer(s) and/or switching equipment. NOTL Hydro will provide planning details upon application for service.

One primary voltage supply will be supplied for each property. NOTL Hydro will establish the point of supply to the property.

3.4.1 Technical Information

Prior to the preparation of a design for a service, the Customer will provide the following information to NOTL Hydro including the approximate date that the Customer requires the electrical service

Site & Grading Plans
Indicate the lot number; plan numbers and the street number. The site plan shall show the location of the Building on the property relative to the property lines, any driveways and parking areas and the distance to the nearest intersection. All elevations shall be shown for all structures and proposed installations.

Mechanical Servicing Plan
Show the location on the property of all services proposed and/or existing such as water, gas, storm and sanitary sewers, telephone, et cetera.

Duct Bank Location
Show the preferred routing of the underground duct bank on the property. This is subject to approval by NOTL Hydro.

Transformer Location
Indicate the preferred location on the property for the high voltage transformation. This is subject to approval by NOTL Hydro and E.S.A.

Electrical Room Floor Plan
Indicate preferred location in the building of the electrical room and the main switchboard. Provide a plan to scale of the electrical room and provision for metering equipment.

Single Line Diagram
Show the main service entrance switch capacity, the required supply voltage, and the number and capacity of all sub-services showing provision for metering facilities, as well as the connected load breakdown for lighting, heating, ventilation, air conditioning et cetera. Also, indicate the estimated initial kilowatt demand and ultimate maximum demands.

3.4.2 *Transformation*

The customer may request NOTL Hydro to supply transformation and the customer will pay 100% of the actual cost.

NOTL Hydro may accept ownership of padmount transformers for installations up to and including 750 kVA-120/208 volt or 1500 kVA-347/600 volt.

NOTL Hydro may accept ownership of vault transformers for installation up to and including, 3 @ 500 kVA (1500 kVA total). The customer will provide a transformer vault that meets the OESC and NOTL Hydro requirements.

3.5 General Service (Above 1000 kW)

All non-residential Customers with an average peak demand of 1000 kW or higher over the past twelve months are to be classified as Customers over 1000 kW. For new Customers without prior billing history, the peak demand will be based on 90% of the installed transformer capacity.

Where a primary service is provided to a Customer-owned substation the Customer shall install and maintain such equipment in accordance with all applicable laws, codes, regulations, and NOTL Hydro's requirements for high voltage installations. NOTL Hydro will provide planning details upon application for service

Customer-owned substations are a collection of transformers and switchgear located in a suitable room or enclosure owned and maintained by the Customer, and supplied at primary voltage: i.e. the Supply Voltage is greater than 750 volts.

The same information and considerations apply as for other general service customers. Refer to Section 3.4 for Applicable Requirements.

3.6 Embedded Generation

NOTL Hydro will provide a connection to the NOTL Hydro Distribution System, where it is technically feasible. The cost of the connection and related protection t assure the public employees and security of the system will be charged to the embedded generator.

NOTL Hydro should be consulted for specific requirements and obligations.

3.7 Embedded Market Participant

All embedded market participants, within the jurisdiction of NOTL Hydro, once approved by the IMO are required to inform NOTL Hydro of their approved status in writing, 30 days prior to their participation in the Ontario Electricity Market.

NOTL Hydro should be consulted for specific requirements and obligations.

3.8 Embedded Distributor

All embedded distributors within the service jurisdiction of NOTL Hydro are required to inform NOTL Hydro of their status in writing 30 days prior to the supply of energy from NOTL Hydro. The terms and conditions applicable to the connection of an embedded distributor shall be included in the Connection Agreement with NOTL Hydro.

NOTL Hydro should be consulted for specific requirements and obligations.

3.9 Unmetered Connections

3.9.1 Street Lighting

All services supplied to street lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. For rate structure details refer to NOTL Hydro's Schedule of Rates. The owner of the street lighting service will provide conductor to the point of supply designated by NOTL Hydro. NOTL Hydro will connect street lighting services on a cost recovery basis. The ownership demarcation point is at the point of supply designated by NOTL Hydro.

3.9.2 Traffic Signals

Traffic signal installations and equipment are subject to O.E.S.C. requirements.

Traffic signals shall have a rate structure equal to general service (< 50 kW) class customer.

The ownership demarcation point is as follows:

Overhead –The top of the customers mast

Underground – The designated connection point to NOTL Hydro System. The customer will be required to provide underground conductor to the connection point.

3.9.3 Bus Shelters, Telephone booths, Signs and Miscellaneous Unmetered Loads

The above service types shall have a rate structure as General Service (< 50 kW) Class Customers and have the same terms and conditions as outlined in Section 3.8.2 above titled "Traffic Signals and Pedestrian X-walk signals/beacons".

The method and location of supply will vary and shall be established for each application through consultation with NOTL Hydro.

Section 4 – GLOSSARY OF TERMS

Sources for definitions:

A	Electricity Act, 1998, Schedule A, Section 2, Definitions
MR	Market Rules for the Ontario Electricity Market, Chapter 11, Definitions
TDL	Transitional Distribution License, Part I, Definitions
TTL	Transitional Transmission License, Part I, Definitions
DSC	Distribution System Code Definitions
RSC	Retail Settlement Code Definitions

"Accounting Procedures Handbook" means the handbook approved by the Board and in effect at the relevant time, which specifies the accounting records, accounting principles and accounting separation standards to be followed by the distributor; (TDL, DSC)

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; (TDL, DSC)

"ancillary services" means services necessary to maintain the reliability of the IMO controlled grid; including frequency control, voltage control, reactive power and operating reserve services; (MR, TDL, DSC)

"apartment building" means a structure containing four or more dwelling units having access from an interior corridor system or common entrance;

"apparent power" means the total power measured in kiloVolt Amperes (kVA);

"application for service" means the agreement or contract with NOTL Hydro under which electrical service is requested;

"bandwidth" means a distributor's defined tolerance used to flag data for further scrutiny at the stage in the VEE (validating, estimating and editing) process where a current reading is compared to a reading from an equivalent historical billing period For example, a 30 percent bandwidth means a current reading that is either 30 percent lower or 30 percent higher than the measurement from an equivalent historical billing period will be identified by the VEE process as requiring further scrutiny and verification; (DSC)

"billing demand" means the metered demand or connected load after necessary adjustments have been made for power factor, intermittent rating, transformer losses and minimum billing. A measurement in kiloWatts (kW) of the maximum rate at which electricity is consumed during a billing period;

"Board" or **"OEB"** means the Ontario Energy Board; (A, TDL, DSC)

"building" means a building, portion of a building, structure or facility;

"complex metering installation" means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed; (DSC)

“Conditions of Service” means the document developed by a distributor in accordance with subsection 2.4 of the Code that describes the operating practices and connection rules for the distributor; (DSC)

“connection” means the process of installing and activating connection assets in order to distribute electricity to a Customer; (DSC)

“Connection Agreement” means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to that connection; (DSC)

“connection assets” means that portion of the distribution system used to connect a Customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor’ s main distribution system and the ownership demarcation point with that Customer; (DSC)

“Consumer” means a person who uses, for the person’ s own consumption, electricity that the person did not generate; (A, MR, TDL, DSC)

“Customer” means a person that has contracted for or intends to contract for connection of a building. This includes developers of residential or commercial subdivisions; (DSC)

"demand" means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes; (DSC)

“demand meter” means a meter that measures a Consumer’s peak usage during a specified period of time; (DSC)

"developer" means a person or persons owning property for which new or modified electrical services are to be installed;

“disconnection” means a deactivation of connection assets that results in cessation of distribution services to a Consumer; (DSC)

“distribute”, with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less; (A, MR, TDL, DSC)

“distribution losses” means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows; (DSC)

“distribution loss factor” means a factor or factors by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system; (RSC)

“distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the Board under section 78 of the Ontario Energy Board Act; (RSC, DSC)

“distribution system” means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many Customers and the connection assets used to connect a Customer to the main distribution system; (A, MR, TDL, DSC)

“Distribution System Code” means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to Customers and retailers and provides minimum technical operating standards of distribution systems; (TDL, DSC)

“distributor” means a person who owns or operates a distribution system; (A, MR, TDL, DSC)

"duct bank" means two or more ducts that may be encased in concrete used for the purpose of containing and protecting underground electric cables;

“Electricity Act” means the Electricity Act, 1998, S.O. 1998, c.15, Schedule A; (MR TDL, DSC)

“Electrical Safety Authority” or **“ESA”** means the person or body designated under the Electricity Act regulations as the Electrical Safety Authority; (A)

"embedded distributor” means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor; (RSC, DSC)

“embedded generator” or **“embedded generation facility”** means a generator whose generation facility is not directly connected to the IMO-controlled grid but instead is connected to a distribution system; (DSC)

“embedded retail generator” means an embedded generator that settles through a distributor’s retail settlements system and is not a wholesale market participant; (DSC)

“embedded wholesale Consumer” means a Consumer who is a wholesale market participant whose facility is not directly connected to the IMO-controlled grid but is connected to a distribution system; (DSC)

“embedded wholesale generator” means an embedded generator that is a wholesale market participant; (DSC)

“emergency” means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system; (DSC)

“emergency backup” means a generation facility that has a transfer switch that isolates it from a distribution system; (DSC)

"energy" means the product of power multiplied by time, usually expressed in kilowatt-hours (kWH);

“Energy Competition Act” means the Energy Competition Act, 1998, S.O. 1998, c. 15; (MR)

"energy diversion" means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter readings, tap off load(s) before revenue meter or meter tampering;

“enhancement” means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth; (DSC)

“expansion” means an addition to a distribution system in response to a request for additional Customer connections that otherwise could not be made; for example, by increasing the length of the distribution system; (DSC)

"extreme operating conditions" means extreme operating conditions as defined in the Canadian Standards Association ("CSA") Standard CAN3-C235-87 (latest edition);

"general service" means any service supplied to premises other than those designated as Residential and less than 50kW, Large User, or Municipal Street Lighting. This includes multi-unit residential establishments such as apartments buildings supplied through one service (bulk-metered);

“generate”, with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system; (A, TDL, DSC)

“generation facility” means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose; (A, MR, TDL, DSC)

“generator” means a person who owns or operates a generation facility; (A, MR, TDL, DSC)

“good utility practice” means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America; (MR, DSC)

"house service" means that portion of the electrical service in a multiple occupancy facility which is common to all occupants, (i.e. parking lot lighting, sign service, corridor and walkway lighting, et cetera);

“IEC” means International Electrotechnical Commission;

“IEEE” means Institute of Electrical and Electronics Engineers;

“IMO” means the Independent Electricity Market Operator established under the Electricity Act; (A, TDL, DSC)

“IMO-controlled grid” means the transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operation; (A, TDL, DSC)

“interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis; (RSC, DSC)

"load factor" means the ratio of average demand for a designated time period (usually one month) to the maximum demand occurring in that period;

“load transfer” means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point; (DSC)

“load transfer Customer” means a Customer that is provided distribution services through a load transfer; (DSC)

"main service" refers to NOTL Hydro’s incoming cables, bus duct, disconnecting and protective equipment for a Building or from which all other metered sub-services are taken;

“market participant” has the meaning prescribed in the Market Rules;

“Market Rules” means the rules made under section 32 of the Electricity Act; (MR, TDL, DSC)

“Measurement Canada” means the Special Operating Agency established in August 1996 by the Electricity and Gas Inspection Act, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131; (DSC)

“meter service provider” means any entity that performs metering services on behalf of a distributor; (DSC)

“meter installation” means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment; (RSC, DSC)

"meter socket" means the mounting device for accommodating a socket type revenue meter;

“metering services” means installation, testing, reading and maintenance of meters; (DSC)

“MIST meter” means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to “Metering Inside the Settlement Timeframe;” (RSC, DSC)

“MOST meter” means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to “Metering Outside the Settlement Timeframe;” (RSC, DSC)

"multiple dwelling" means a Building which contains more than one self-contained dwelling unit;

"municipal street lighting" means all services supplied to street lighting equipment owned and operated for a municipal corporation;

“non-competitive electricity costs” means costs for services from the IMO that are not deemed by the Board to be competitive electricity services plus costs for distribution services, other than Standard Supply Service (SSS); (RSC)

"normal operating conditions" means the operating conditions comply with the standards set by the Canadian Standards Association ("CSA") Standard CAN3-C235- 87 (latest edition);

“Ontario Energy Board Act” means the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B; (MR, DSC)

“operational demarcation point” means the physical location at which a distributor’s responsibility for operational control of distribution equipment including connection assets ends at the Customer; (DSC)

“ownership demarcation point” means the physical location at which a distributor’ s ownership of distribution equipment including connection assets ends at the Customer; (DSC)

“performance standards” means the performance targets for the distribution and connection activities of the distributor as established by the Board pursuant to the Ontario Energy Board Act and in the Rate Handbook; (DSC)

"person" includes an individual, a corporation, sole proprietorship, partnership, unincorporated organization, unincorporated association, body corporate, and any other legal entity;

“physical distributor” with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer Customer, but is not responsible for connecting and billing the load transfer Customer directly; (DSC)

"power factor" means the ratio between Real Power and Apparent Power (i.e. kW/kVA);

"primary service" means any service which is supplied with a nominal voltage greater than 750 volts;

"private property" means the property beyond the existing public street allowances;

“rate” means any rate, charge or other consideration, and includes a penalty for late payment; (TDL, DSC)

“Rate Handbook” means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates; (RSC, DSC)

"reactive power" means the power component which does not produce work but is necessary to allow some equipment to operate, and is measured in kiloVolt Amperes Reactive (kVAR);

"real power" means the power component required to do real work, which is measured in kiloWatts (kW);

“Regulations” means the regulations made under the *Ontario Energy Board Act* or the *Electricity Act*; (TDL, DSC)

"residential service" means a service which is less than 50kW supplied to single family dwelling units that is for domestic or household purposes, including seasonal occupancy.

"retail", with respect to electricity means,

a) to sell or offer to sell electricity to a Consumer
b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) to act or offer to act as an agent or broker for a Consumer with respect to the sale or offering for sale of electricity; (A, MR, TDL, DSC)

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and Consumers and provides for tracking and facilitating Consumers transfers among competitive retailers; (TDL, DSC)

"retailer" means a person who retails electricity; (A, MR, TDL, DSC)

"secondary service" means any service which is supplied with a nominal voltage less than 750 Volts;

"service agreement" means the agreement that sets out the relationship between a licensed retailer and a distributor, in accordance with the provisions of Chapter 12 of the Retail Settlement Code; (RSC)

"service area" with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity; (A, TDL, DSC)

"service date" means the date that the Customer and NOTL Hydro mutually agree upon to begin the supply of electricity by NOTL Hydro;

"Standard Supply Service Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act; (TDL)

"sub-service" means a separately metered service that is taken from the main Building service;

"supply voltage" means the voltage measured at the Customer's main service entrance equipment (typically below 750 volts). Operating conditions are defined in the Canadian Standards Association ("CSA") Standard CAN3-C235 (latest edition);

"temporary service" means an electrical service granted temporarily for such purposes as construction, real estate sales, trailers, et cetera;

"terminal pole" refers to the NOTL Hydro's distribution pole on which the service supply cables are terminated;

"total losses" means the sum of distribution losses and unaccounted for energy; (DSC)

"transformer room" means an isolated enclosure built to applicable codes to house transformers and associated electrical equipment;

"transmission system" means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose; (A, MR, TDL, DSC)

"Transmission System Code" means the code, approved by the Board, that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with Customers, as well as establishing the standards for connection of Customers to, and expansion of a transmission system; (DSC)

"transmit", with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts; (A, TDL, DSC)

"transmitter" means a person who owns or operates a transmission system; (A, MR, TDL, DSC)

"unaccounted for energy" means all energy losses that can not be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and unmetered loads, energy theft and non-attributable billing errors; (DSC)

"unmetered loads" means electricity consumption that is not metered and is billed based on estimated usage; (DSC)

"validating, estimating and editing (VEE)" means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes; (MR, DSC)

"wholesale buyer" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator; (TDL, DSC)

"wholesale market participant" means a person that sells or purchases electricity or ancillary services through the IMO- administered markets; (RSC, DSC)

"wholesale settlement cost" means costs for both competitive and non-competitive electricity services billed to a distributor by the IMO or a host distributor, or provided by an embedded retail generator or by a neighboring distributor; (RSC, DSC)

"wholesale supplier" means a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person, other than a Consumer; (TDL, DSC)

Niagara On-The-Lake HYDRO

AESTATEM VIREMUS

APPENDIX 1 – Credit & Collection Policy

Credit & Collection Policy
Niagara on the Lake Hydro Inc

Purpose:

This Credit and Collection Policy (referred to in this document as the "Policy") sets out the standards of Niagara on the Lake Hydro Inc. ("Distributor") with respect to customer bill payment deadlines, late payment charges, collection costs, and customer deposits. The Policy applies to all customers of Distributor, in the manner set out herein. This Policy was developed in cooperation with other electricity distributors that are members of the Niagara Erie Public Power Alliance, with the intention of establishing fair and equitable credit and collection policies for customers in the Distributor service area. This Policy will form part of Distributor Conditions of Service.

Authority:

Local Electricity Distribution Companies ("Distributors" or "LDCs") are regulated by the Ontario Energy Board (the "OEB"), by the powers granted to the OEB by the Ontario Provincial Government through the enactment of Bill 35, the *Energy Competition Act, 1998,* of which Schedule A; the *Electricity Act, 1998*; and Schedule B, *the Ontario Energy Board Act, 1998* (the "Acts"*)* form parts.

The Acts, and various Codes and Handbooks established by the OEB, including the Retail Settlement Code, the Standard Supply Service Code, the Distribution System Code and the Electricity Distribution Rate Handbook, provide for minimum payment periods, authorize Distributors to use those means available to them under law to mitigate consumer non-payment risk, and allow Distributors to establish prudent and commercially sound Credit and Collection Policies.

Methodology:

With the enactment of the *Energy Competition Act,* local Municipal Electric Utilities (MEUs) were required to incorporate under the Ontario *Business Corporations Act* (OBCA). Under the Municipal Act and the Public Utilities Act, MEUs had the ability to collect any outstanding arrears by placing a lien on the owner's property. Once the MEU was incorporated as an OBCA corporation, it no longer had the power to lien a property and no longer had the ability to add a delinquent customer's utility bill to the municipal tax rolls. This Policy provides for a means of obtaining security from customers for the payment of their accounts, with the primary objective of reducing the number and amount of potential annual write-offs Distributor may experience due to poor customer payment practices.

In the development of this policy, Distributor considered whether it would require customers to provide Security Deposits. It was concluded that it is commercially reasonable, and typical of other commercial entities including banks and credit card issuers, to consider the creditworthiness of a potential customer prior to providing the customer with credit. This Policy was developed with the assumption that a current residential customer whose account with Distributor is in good standing will remain connected to the distribution system without a Security Deposit provided that the customer meets the generally accepted commercial credit requirements set out in Section 9 of this policy. However, all new customers will be required to provide security in a form acceptable to Distributor, and in an amount set out in this Policy, prior to being permitted to connect to the distribution system. Where an existing customer no longer meets the criteria for an exemption from the requirement to provide a Security Deposit, the customer will provide a Security Deposit in the manner set out in this Policy as a condition of Distributor's continued supply of electricity to that customer.

Effective Date:

The effective date of this Policy is September 9, 2002.

1. **Contract:**

   All new customers or existing customers relocating to a new service address in the Niagara on the Lake Hydro Inc service area must enter into a Contract in the form provided by Niagara on the Lake Hydro Inc. This agreement, when signed, forms a binding contract between the Customer and the Niagara on the Lake Hydro Inc, and will be evidence of the fact that the Niagara on the Lake Hydro Inc and the Customer have accepted and mutually agreed to the terms of the Contract.

   Personal information such as the customer's driver's licence number, the name of the customer's employer, and the customer's social insurance number will be requested from all customers (photo identification is preferred).

2. **Account Set-up Charge:**

   Customers will be subject to an Account set-up charge as approved by the OEB.

3. **Security Deposit:**

   A "new customer" is defined in this Policy as a consumer of electricity that does not have an account with Niagara on the Lake Hydro Inc prior to the date that this Policy comes into force, and that requests that Niagara on the Lake Hydro Inc open an account with the consumer and commence the supply of electricity to the consumer on or after the date that this Policy comes into force. Security Deposits will be required from all new customers, to the extent permitted by the

OEB's Retail Settlement Code, regardless of their Customer Class, and regardless of whether they are on Standard Supply Service (SSS) or they have entered into contracts with electricity retailers. The amount of the Security Deposit for each class will be calculated according to sections 5 & 8 of this Policy.

Where the customer is a party to a contract with an electricity retailer, the following policies shall apply according to the billing option selected by the retailer.

3.1 Distributor-Consolidated Billing and Standard Supply Service

Under these options, Niagara on the Lake Hydro Inc will continue to issue a bill to the customer. Niagara on the Lake Hydro Inc is responsible for customer non-payment risk. Niagara on the Lake Hydro Inc will impose a Security deposit depending upon its assessment of the customer's likely risk of nonpayment, according to the requirements set out below.

3.2 Retailer-Consolidated Billing

Under this option, Niagara on the Lake Hydro Inc will not issue a bill to a customer. The retailer is responsible for issuing the bill to the customer, and for customer non-payment risk. Niagara on the Lake Hydro Inc will not require a security deposit from the customer. If Niagara on the Lake Hydro Inc is in possession of a customer's Security Deposit at the time of a switch to retailer-consolidated billing, the deposit shall be applied to the customer's final bill under the billing type in respect of which Niagara on the Lake Hydro Inc has required a Security Deposit, and any unapplied balance of the Security Deposit will be returned to the customer.

3.3 Split Billing

Under this option Niagara on the Lake Hydro Inc and a retailer shall each be responsible for customer nonpayment risk for the bills that each issues to the customer. If a customer already has a deposit with Niagara on the Lake Hydro Inc, they will retain a portion of the deposit amount that reflects the non-payment risk associated with the new billing option. Any excess deposit amount will be returned to the customer. For customers making new application for service, Niagara on the Lake Hydro Inc shall require a Security Deposit in an amount that shall depend upon Niagara on the Lake Hydro Inc's assessment of the customer's likely risk of non-payment, according to the requirements set out below.

4.0 Residential Customers

4.1 Every new customer requesting the establishment of an account with Niagara on the Lake Hydro Inc as a Residential customer and the delivery of electricity to the customer's service address shall pay a Security Deposit prior to the commencement of service to the customer. New customers maybe exempted through a letter of reference from another Hydro company proving the requirements outlined in 4.2 have been met.

4.2 A Residential customer with an "Acceptable Payment History" is defined as a Residential customer with no more than:

(i) One (1) Cheque returned for Non-Sufficient Funds or for reasons of non-payment initiated by the customer in the preceding 12 consecutive months; or

(ii) Two (2) Disconnect Notices in the preceding 12 consecutive months or;

(iii) One (1) Disconnection of service in the preceding 12 month.

4.3 Residential Customers Security Deposits can be prearranged in the form of Cash or current dated cheque.

4.4 A Residential customer that is not a new customer will not be required to provide a Security Deposit to Niagara on the Lake Hydro Inc, provided that the customer has an Acceptable Payment History, as defined in Section 4.2 above, as of the date that this Policy comes into force, and provided further that the customer maintains that Acceptable Payment History.

4.5 Where a Residential customer was not required to provide a Security Deposit pursuant to Section 4.1 above, and where that customer no longer has an Acceptable Payment History as a result of having exceeded any of the limits set out in Subsection 4.2, the customer shall provide a Security Deposit to Niagara on the Lake Hydro Inc, in an amount calculated in accordance with Section 4.7below.

4.6 Where a Security Deposit becomes payable by the Residential customer, Niagara on the Lake Hydro Inc will notify the customer that the Security Deposit is payable, and will add the amount of the Security Deposit to the next bill issued to the customer..

4.7 All new Residential customers will be required to provide Niagara on the Lake Hydro Inc with Security Deposits in the following amounts, as applicable, prior to the commencement of service:

Customers billed Monthly:	2.5 x the highest monthly bill for the service address in the preceding 12 month period or, in the case of a service address to which service has not been provided throughout the preceding 12 month period, 2.5 x the highest bill for a building or unit with a similar anticipated load profile.

5.0 General Service and Large Use Customers:

5.1. Every new customer requesting the establishment of an account with Niagara on the Lake Hydro Inc as a General Service or Large User customer and the delivery of electricity to the customer's service address shall pay a Security Deposit prior to the commencement of service to the customer, in an amount calculated as follows:

Customers billed Monthly: 2.5 x the highest monthly bill for the service address in the preceding 12 month period or, in the case of a service address to which equivalent service has not been provided throughout the preceding 12 month period, 2.5 x the highest bill for a building or unit with a similar anticipated load profile

5.2 Security deposits may be prearranged in the form of any of the following:

i. Cash or certified cheque;

ii. An irrevocable Letter of Credit from a Chartered Bank, Trust Company or Credit Union in a form acceptable to Niagara on the Lake Hydro Inc, valid for a minimum of 3 years with a rolling validity of a minimum of 3 months from signing date of service agreement.

iii. Surety Bond in a form acceptable to Niagara on the Lake Hydro Inc.

iv. A guarantee in a form acceptable to Niagara on the Lake Hydro Inc provided by a person that is an affiliate of the customer, as the term "affiliate" is defined in the Business Corporations Act (Ontario), and that has a credit rating from a major bond rating agency such as Standard and Poors or such other agency as may be identified by Niagara on the Lake Hydro Inc.

5.3 Those customers that are able to provide a Specified Credit Rating will be eligible for a reduction in their security deposit as outlined in the charts below.

With Specified Credit Ratings

Table 1

Credit Rating with Standard and Poor's Rating Terminology	Allowable reduction in Security Deposit
AAA- and above or equivalent	100% of deposit calculated in accordance with section 7.1
AA-, AA, AA+ or equivalent	85% of deposit calculated in accordance with section 7.1
A-, A, A+ or equivalent	75% of deposit calculated in accordance with section 7.1
BBB-, BBB, BBB+ or equivalent	50% of deposit calculated in accordance with section 7.1
Below BBB- or equivalent	0

5.4 A General Service customer that is not a new customer will not be required to provide a Security Deposit to Niagara on the Lake Hydro Inc, provided that the customer has an Acceptable Payment History, as defined in Section 6.1 below, as of the date that this Policy comes into force, and provided further that the customer maintains that Acceptable Payment History.

6.0 Delinquent General Service Accounts:

6.1 In order to maintain a reduction or waiver of its Security Deposit requirement pursuant to Section 5.3 or 5.4 above, a General Service or Large Use customer must maintain its "Acceptable Payment History". For General Service and Large Use customers, "Acceptable Payment History" is defined as a General Service or Large Use customer with no more than:

(i) One (1) Cheque returned for Non-Sufficient Funds or for reasons of non-payment initiated by the customer in the preceding 12 consecutive months; or

(ii) Two (2) Disconnect Notices in the preceding 12 consecutive months or;

(iii) One (1) Disconnection of service in the preceding 12 month.

If a General Service or Large Use customer's deposit is waived or reduced due to the provisions in section 5 above and loses its Acceptable Payment History status by exceeding any of the limits set out in this Section 6, the customer shall provide to Niagara on the Lake Hydro Inc a Security Deposit from the customer as calculated in accordance with section 5.1 of this Policy.

6.2 Where a Security Deposit becomes payable by the General Service customer, Niagara on the Lake Hydro Inc will notify the customer that the Security Deposit is payable, and will add the amount of the Security Deposit to the next bill issued to the customer.

7. Collection of Security Deposit:

Security deposits are required to be paid in full when the customer is making application for service, or prior to connection or provision of service i.e., before move-in, and in certain circumstances, as a condition of continued service. Niagara on the Lake Hydro Inc, may extend special payment arrangements to those customers unable to make full payment of the deposit. In these circumstances, Niagara on the Lake Hydro Inc will provide the customer with 30 days to make full payment of the deposit. After 30 days, should the customer fail to make full payment of the deposit, Niagara on the Lake Hydro Inc will forward a written reminder of the overdue account followed by a disconnect notice after four (4) business days. Non-payment of the deposit will result in disconnection of service as detailed in Sections 15 and 16.

8. Security Deposit Adjustments:

Security Deposits will be reviewed quarterly and may be adjusted accordingly. Adjustments will be debited or credited to the customer's account on the bill following the adjustment.

9. Retention/Refund of Deposit:

9.1 Security deposits will be refunded to a customer, in whole or in part according to the circumstances giving rise to the refund, upon an application for a refund, and only where:

(i) The customer terminates its service with Niagara on the Lake Hydro Inc. The Security Deposit will be applied to the balance owing on the customer's final bill, and any amount not required for this purpose will be refunded to the customer; or

(ii) If a Customer switches to retailer-consolidated or split billing, in which case the Security Deposit will be reduced to a level set out in the Ontario Energy Board's Retail Settlement Code, after Niagara on the Lake Hydro Inc has recovered any outstanding arrears on the customer's account.

9.2 Where the customer moves within the Niagara on the Lake Hydro Inc service area, the Security Deposit may be applied to the customer's account in respect of the customer's new service address. Niagara on the Lake Hydro Inc may adjust the Security Deposit in consideration of the historical consumption or the customer's anticipated load profile at the new service address, in accordance with Sections 4.2 and 5.1 above.

10. Interest on Security Deposit:

(i) Simple interest for each full calendar month the deposit is held will be paid annually on all cash Security Deposits retained more than 12 months. Interest will not be paid on Letters of Credit or other forms of Security Deposit.

(ii) Interest earned will be applied to customer accounts or applied to the Security Deposit at the discretion of the Niagara on the Lake Hydro Inc, at their year-end for each prior period, or whenever Security Deposits are returned, whichever occurs first.

11. Payment of Bills:

The customer must make payment of any outstanding accounts to Niagara on the Lake Hydro Inc on the due date as identified on the bill. Where a payment is made by mail, the payment will be deemed to be made on the date post- marked. Where a payment is made at a financial institution acceptable to Niagara on the Lake Hydro Inc, the payment will be deemed to be made when stamped/acknowledged by the financial institution. A partial payment will be applied to any outstanding arrears before being applied to the current billing, and partial payments will be applied first to non-regulated charges.

12. Late Payment Charge:

Late payment charges will apply to any arrears unpaid after the due date of the bill. Niagara on the Lake Hydro Inc will charge late payment charges at an interest rate approved by the Ontario Energy Board as per Niagara on the Lake Hydro Inc.'s annual Rate order submission.

13. Returned Cheques:

Any cheque or pre-authorized payments charged back by the bank for whatever reasons shall be corrected immediately by the customer. Any denied payment will be reversed on the customer's account and a returned cheque fee charged to the customer in accordance with Niagara on the Lake Hydro Inc.'s Electricity Distribution Rate Order. Niagara on the Lake Hydro Inc will attempt to make contact with the customer to obtain payment for any outstanding amounts owed by the customer on account of the returned cheque, including all associated Service Charges. Should such an attempt fail, Niagara on the Lake Hydro Inc shall forward a Disconnect Notice detailing all charges owed by the customer.

14. Load Limiters

Load limiters may be used as alternatives to disconnecting the customer's service from the Distribution grid. Load limiters may be used specifically during the winter months. The intent for the use of load limiters is that it may encourage the customer to pay the utility bill while maintaining a minimum supply of current to operate a furnace for heating the home.

15. Disconnection of Electricity Service:

Where a customer's account is in arrears and where the Ontario Energy Board's Retail Settlement Code permits Niagara on the Lake Hydro Inc to disconnect the customer's service, Niagara on the Lake Hydro Inc will issue a Reminder Notice seven (7) calendar days after the due date in the customer's account, unless payment has been received or payment arrangements acceptable to Niagara on the Lake Hydro Inc have been made. A Disconnect Notice will be issued five (5) calendar days after the Reminder notice unless payment is received or payment arrangements acceptable to Niagara on the Lake Hydro Inc have been made. The disconnection will be completed four (4) calendar days after the Disconnect notice unless payment is received or payment arrangements acceptable to Niagara on the Lake Hydro Inc have been made.

Prior to disconnecting the service a company representative will make reasonable efforts to establish direct contact with the customer in accordance with the Ontario Energy Board's Electricity Distribution Rate Handbook.

Payments must be received at the Niagara on the Lake Hydro Inc's office by 12:00 Noon on or before the scheduled disconnect date. Failure to do so may result in additional re-scheduling and reconnection charges.

16. Reconnection of Electrical Service:

Where the customer's service has been disconnected due to arrears, the customer must pay to Niagara on the Lake Hydro Inc the full amount of the customer's arrears, any Security Deposit that Niagara on the Lake Hydro Inc may require, and payment in full must be received by Niagara on the Lake Hydro Inc before the customer's service will be reconnected. If the customer requests the service to be connected after normal hours of work, full payment must be given to Niagara on the Lake Hydro Inc.'s Service Technician on duty prior to reconnection and an "after hours" service charge will apply. Customers must be present during reconnection.

17. Billing Errors:

Billing errors will be resolved in accordance with Section 7.7 of the Ontario Energy Board's Retail Settlement Code, as that Code may be amended from time to time.

18. Final Bills:

(i) Forwarding Address:

a) If a customer neglects to pay its final bill the Security deposit will be applied to reduce the Final Bill.

b) If the forwarding address is within Niagara on the Lake Hydro Inc.'s service area and the Customer sets up a new account at new forwarding address within Niagara on the Lake Hydro Inc.'s service area, the customer will be provided the option to transfer the balance to the new account or use the Security Deposit to pay the bill and the new Security Deposit will be calculated accordingly.

(ii) No Forwarding Address:

a) If a customer neglects to pay its final bill the Security deposit will be used to reduce the Final Bill.

b) If the amount of the Security Deposit is not sufficient to pay the entire bill amount and the customer moves out of Niagara on the Lake Hydro Inc's service area, Niagara on the Lake Hydro Inc staff will make an attempt to locate forwarding address, and may request the assistance of other licensed Distributors. If this yields no results, the account will be referred to a collection agency.

(iii) If a personal guarantee has been provided by a General Service customer or an officer or director or other principal of a General Service customer in that customer's Service Agreement with Niagara on the Lake Hydro Inc, and the individual executing the guarantee has another account of any kind with Niagara on the Lake Hydro Inc, then any amounts outstanding on that final bill may be transferred to that individual's other account.

APPENDIX 2 – Dispute Meter Test-Agent's Fee Policy

NIAGARA-ON-THE-LAKE HYDRO INC.
POLICY MANUAL

BILLING & CUSTOMER SERVICE POLICIES

Revised: April 17, 2003

DISPUTE METER TEST – AGENT'S FEE

The utility presently has a miscellaneous charge on its Schedule of Rates & Charges for minimal recovery of any costs when the utility acts as an agent for customers disputing the accuracy of their electrical meter. An amount of $10.00 is applicable after all other avenues have been pursued and the customer wishes the meter to be tested by Measurement Canada, Industry Canada.

Normal procedure of staff involves an initial interview with the customer reviewing consumption profiles and, if necessary, the installation of a parallel test meter at the location to check accuracy of the billing meter. In some cases, the utility test meter may satisfy the customer that their billing meter is correct. However, in most cases, customers wish to have an independent agency verify the results. Staff provide the customer with the telephone number and address of Measurement Canada, Industry Canada and indicate that if they wish, they may dispute the meter to Measurement Canada, Industry Canada. Customers are also given the option of requesting that Niagara-on-the-Lake Hydro acts as their agent in the dispute. If testing by MCIC verifies the utility billing meter to be correct a $10.00 charge applies.

When acting as the agent for any customers with disputes, a form is filled out by staff and forwarded to MCIC. The finding of MCIC is binding on the utility.

Other than the form required by MCIC, historical information provided by the utility is now retrieved from the billing system and the time for that work is minimal requiring only the generation of a form report.

It is the experience of the utility that any question of accuracy is satisfied once CCAC has confirmed results. This generally does not generate any further requests and disputes do not come up again with those customers.

This service is more of an assistance to customers in confirming accurate billing. The charge is seen more as a minimal recovery of costs and could not be considered cost effective.

It is the opinion of staff that customer satisfaction is more of an issue in this situation and that the utility should waive the charge in the interest of public relations, in all cases, where the customer is requesting the service on a first time basis.

APPENDIX 3 – Underground Practices-Designated Areas Policy

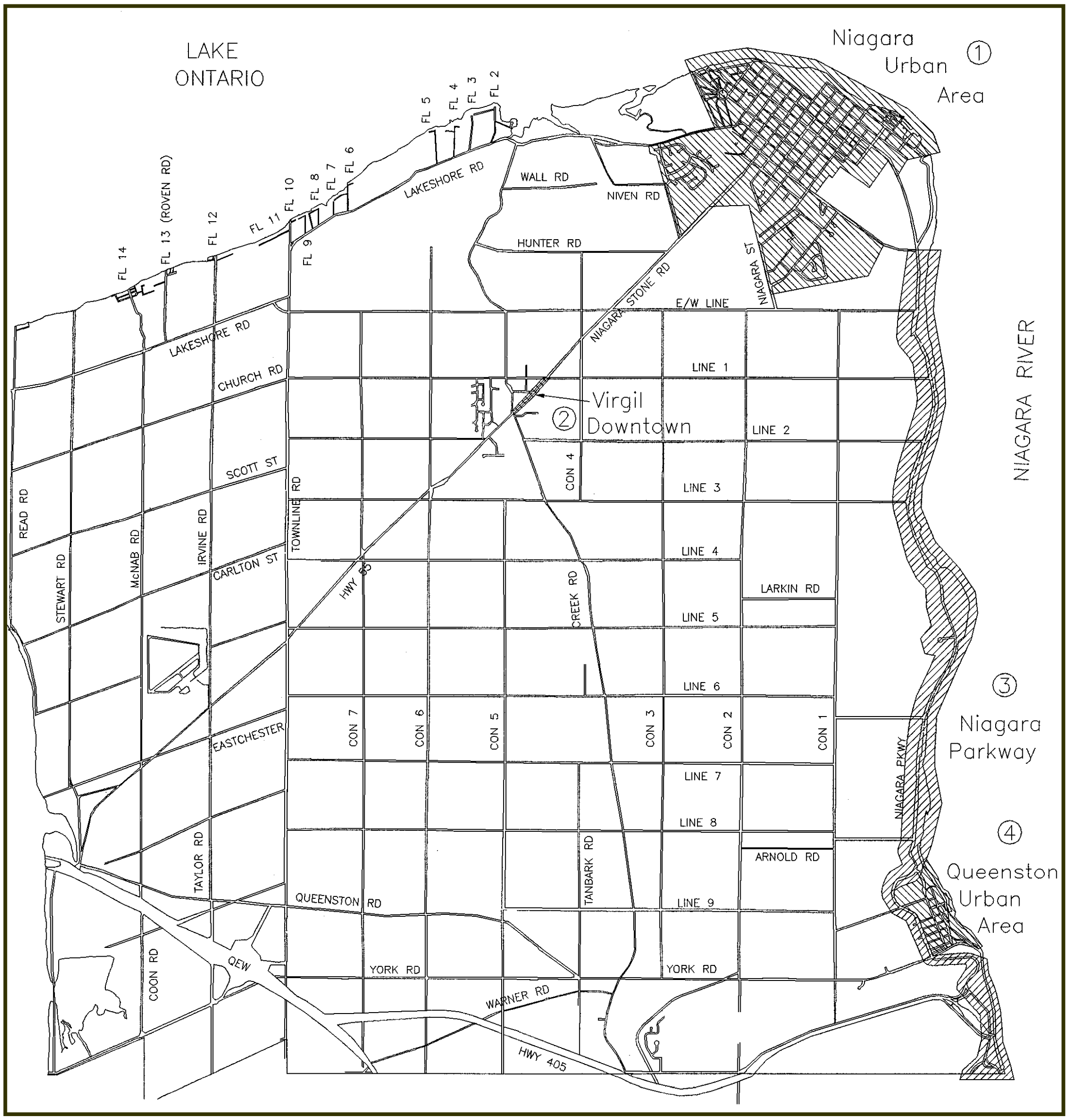
NIAGARA-ON-THE-LAKE HYDRO INC.

ENGINEERING & OPERATIONS POLICIES

February 1997

UNDERGROUND PRACTICES - DESIGNATED AREAS
(Attachment - 5 pages - Maps of Designated Areas)

KEY MAP OF UNDERGROUND AREAS



LEGEND:

1 – Niagara Urban Area

2 – Virgil Downtown

3 – Niagara Parkway

4- Queenston Urban Area

NIAGARA-ON-THE-LAKE HYDRO INC.

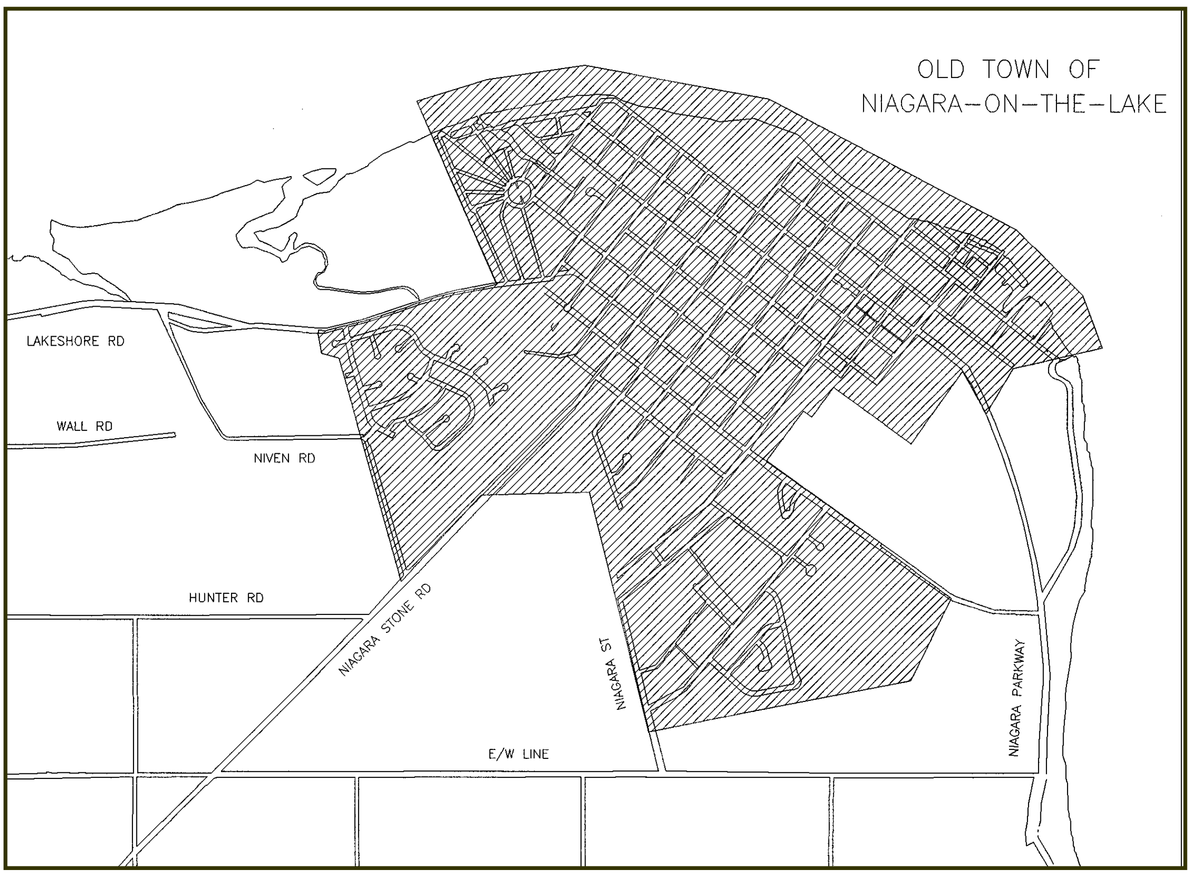
ENGINEERING & OPERATIONS POLICIES

February 1997

UNDERGROUND PRACTICES - DESIGNATED AREAS

(Attachment - 5 pages - Maps of Designated Areas)

1. Niagara Urban Area



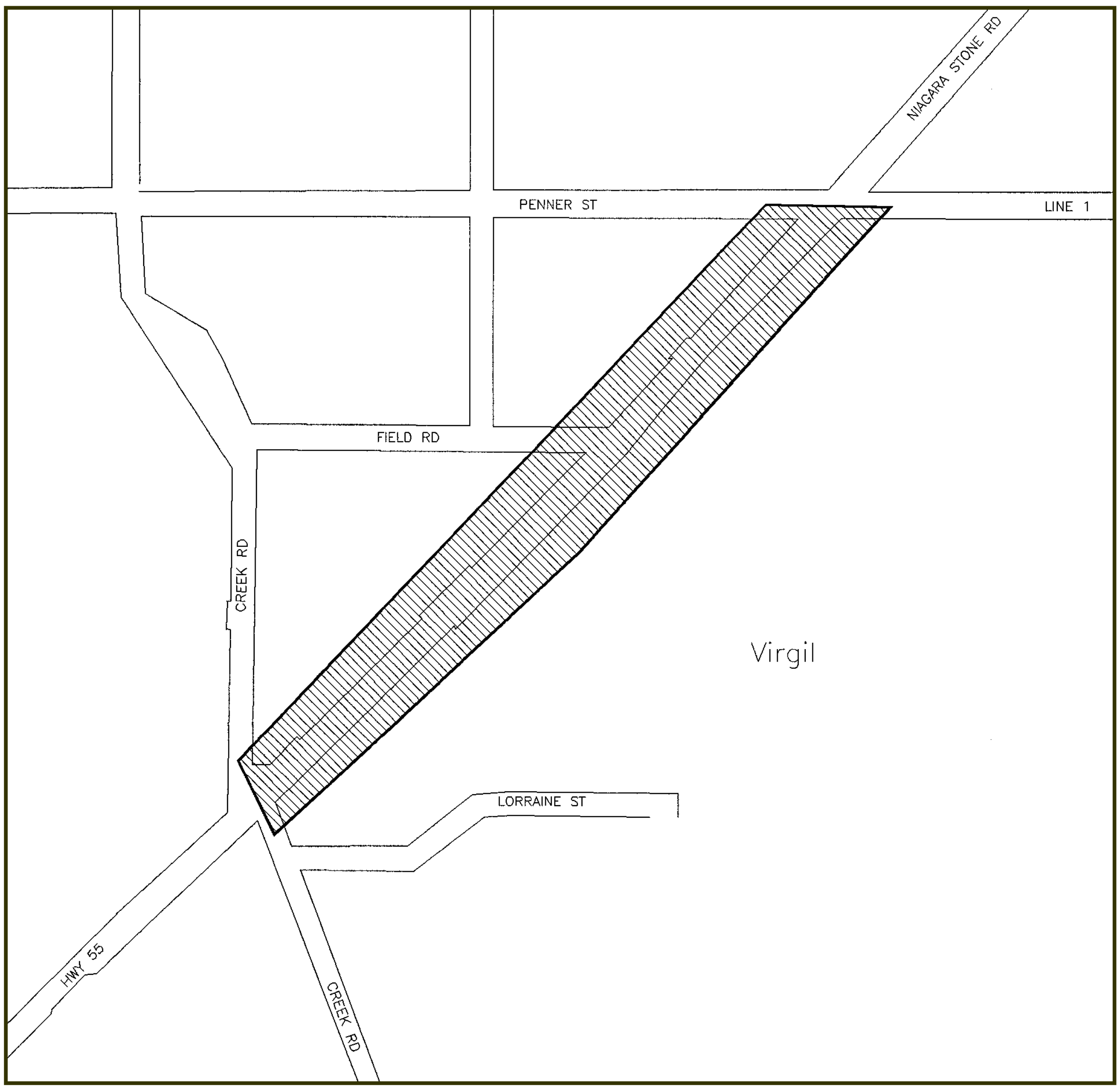
NIAGARA-ON-THE-LAKE HYDRO INC.

ENGINEERING & OPERATIONS POLICIES

February 1997

<u>UNDERGROUND PRACTICES - DESIGNATED AREAS</u>
(Attachment - 5 pages - Maps of Designated Areas)

2. Virgil Downtown



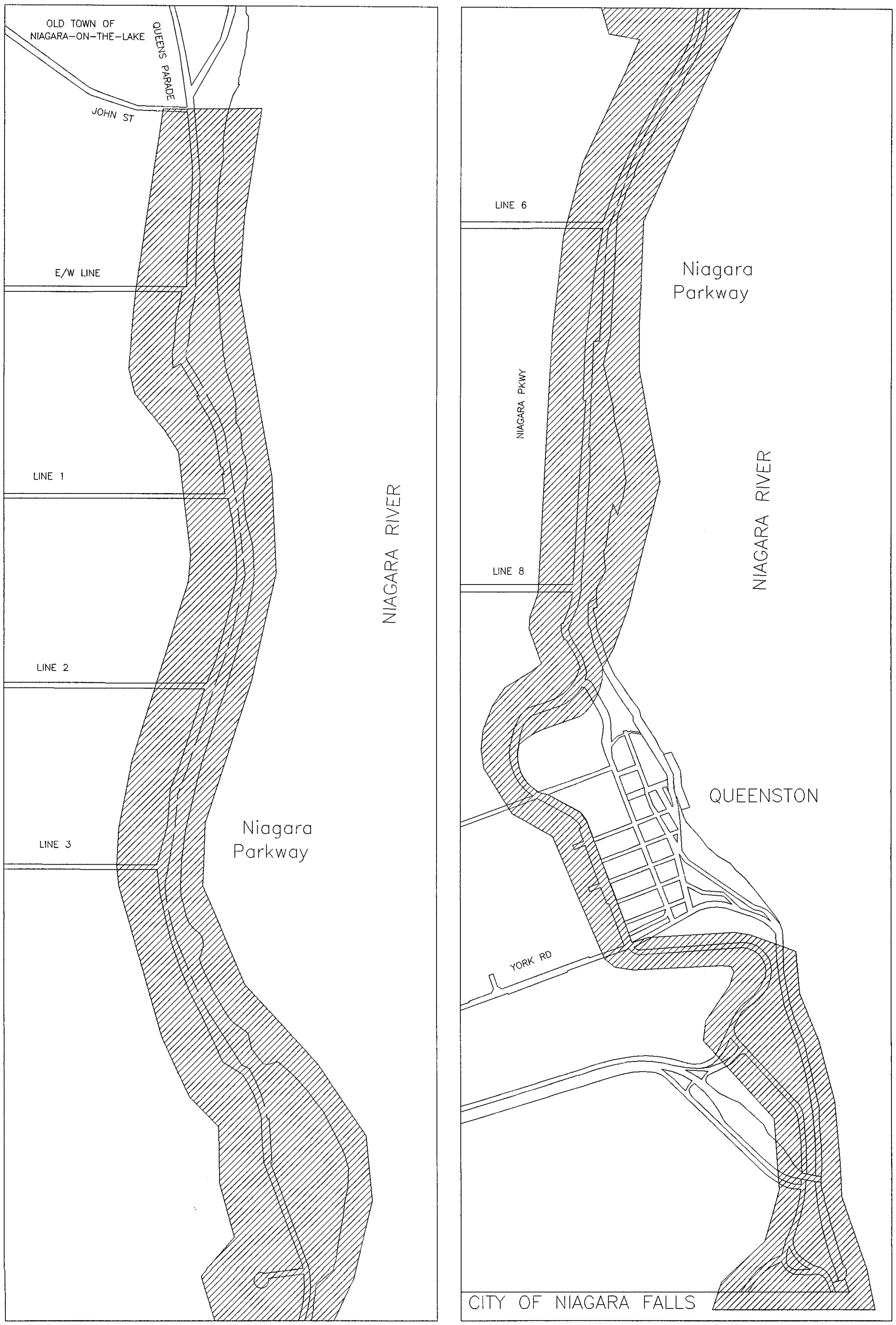
NIAGARA-ON-THE-LAKE HYDRO INC.

ENGINEERING & OPERATIONS POLICIES

February 1997

UNDERGROUND PRACTICES - DESIGNATED AREAS
(Attachment - 5 pages - Maps of Designated Areas)

3. Niagara Parkway



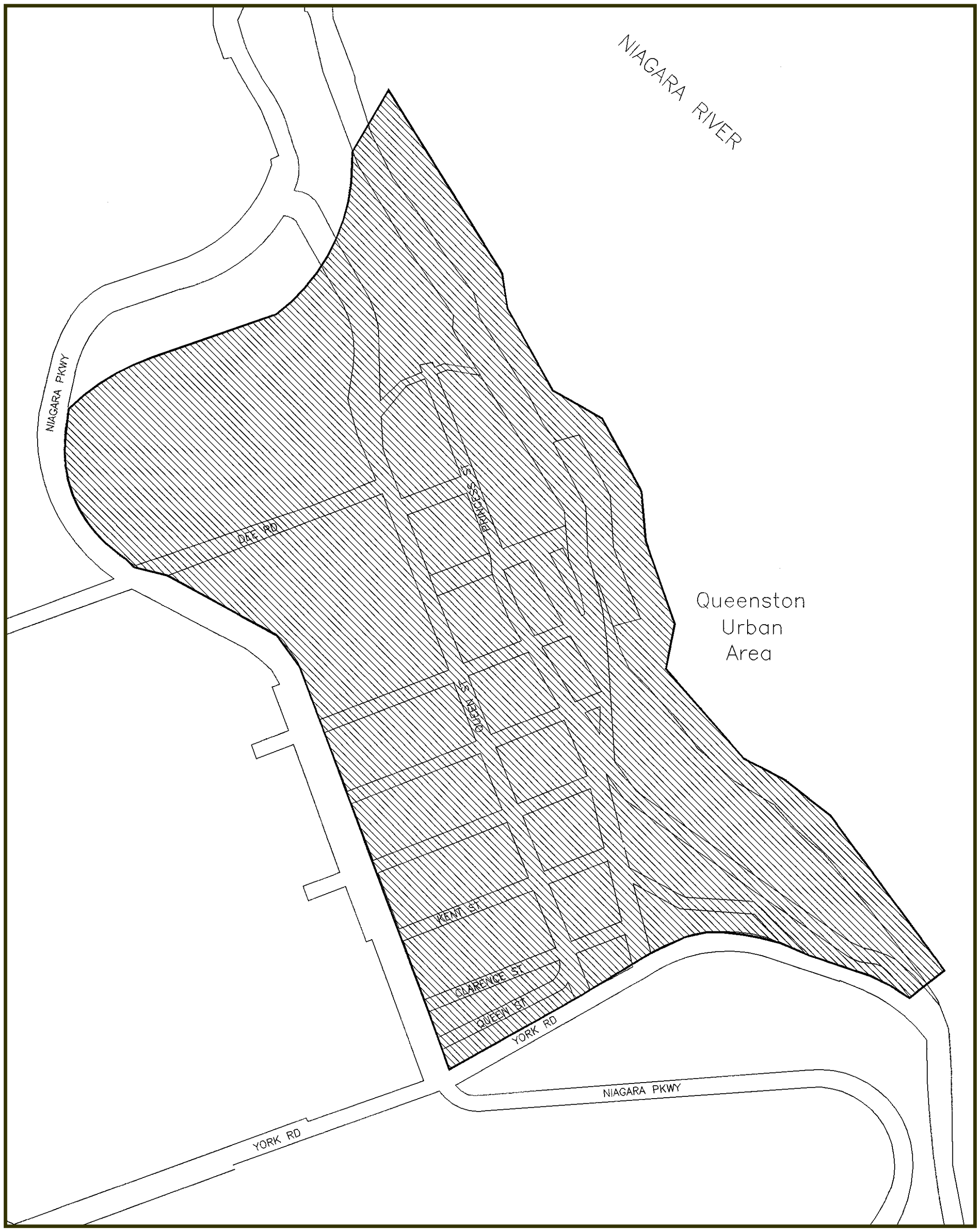
NIAGARA-ON-THE-LAKE HYDRO INC.

ENGINEERING & OPERATIONS POLICIES

February 1997

UNDERGROUND PRACTICES - DESIGNATED AREAS
(Attachment - 5 pages - Maps of Designated Areas)

4. Queenston Urban Area



APPENDIX 4 - TABLES

TABLE 1 – Residential
TABLE 2 – General Service < 50 kV
TABLE 3 – General Service > 50 kV
TABLE 4 – Temporary Service

TABLE 1 – RESIDENTIAL SERVICES

Service Type	Ownership Demarcation Point	Standard Allowance	Basic Connection Fee	Variable Connection Fee	Disconnect Fee (Customer Request)
Overhead 120/240 V 1 Phase 200 A	Top of Customers mast	Up to 30 m of overhead conductor from NOTL Hydro Connection point including connections at pole & service mast Transformation included	Recovered through rates	Customer charged actual cost for labour/material beyond standard allowance	Recovered through rates
Underground 120/240 V 1 Phase 200 A Designated areas	Line side of Customers meter base	30 m overhead conductor Transformation included	Recovered through rates	Customer charged actual cost for underground service installation Less credit for standard allowance Cost calculated from customer property line to meter base	Recovered through rates
Underground 120/240 V 1Phase 200 A Customer request	NOTL Hydro connection point	30 m overhead conductor Transformation included	Recovered through rates	Customer charged actual cost for underground service Installation less credit for standard allowance Cost calculated from customer property line to meter base A $400.00 minimum charge will apply	Recovered through rates
Underground 20/240 V 1 Phase 200 A Subdivision	NOTL Hydro connection point at padmount transformer	Underground service stub to property line Transformation included	Recovered through rates	Customer charged actual cost for underground service Installation cost calculated from service stub at property line to meter base A $400.00 minimum charge will apply	Recovered through rates

TABLE 2 – GENERAL SERVICES – LESS THAN 50 KW

Service type	Ownership Demarcation Point	Standard Allowance	Basic Connection Fee	Variable Connection Fee	Disconnect Fee (Customer Request)
Overhead 120/240 V 1 Phase Up to 400 A	Top of customers mast	Up to 30 m of overhead conductor from NOTL Hydro. Connection point including connections at feed pole & customers service mast Transformation included	Recovered through rates	Customer charged actual costs for labour/material beyond standard allowance	Recovered through rates
Underground 120/240 V 1 Phase Up to 400 A All areas	Line side of customers meter base	30m of overhead conductor (credit) Transformation included	Recovered through rates	Customer charged actual cost for underground service. Installation less credit for standard allowance Cost calculated from NOTL Hydro connection point to meter base	Recovered through rates

TABLE 3 – GENERAL SERVICES – GREATER THAN 50 KW

Service Type	Ownership Demarcation Point	Connection Fees	Disconnect Fee (Customer Request)
Overhead 120/208 V 3 Phase 400A max 347/600 V 3 Phase 200A max Not requiring transformation facilities on customer property	Top of customer mast	Customer pays actual cost for labour, material and transformation	1 disconnect yearly recovered through rates Additional disconnects customer pays actual costs
Overhead Any service requiring transformation on customer property	Primary overhead wire connection at disconnect switch	Customer pays actual cost for labour, material and transformation	1 disconnect yearly recovered through rates Additional disconnects customer pays actual costs
Underground Designated areas From underground system	Primary cable connection to NOTL Hydro system	Customer pays actual cost for labour, material and transformation	1 disconnect yearly recovered through rates Additional disconnects customer pays actual costs
Underground From overhead system	Primary underground cable connection at disconnect switch	Customer pays actual cost for labour, material and transformation	1 disconnect yearly recovered through rates Additional disconnects customer pays actual costs

TABLE 4 – TEMPORARY SERVICES

Service Type	Standard Allowance	Minimum Charge	Variable Connection Fee
Overhead 120/240 V 1 Phase 200 A max	Up to 30 m of overhead conductor	$ 250.00	Customer charged actual cost for labour/material beyond standard allowance
Overhead 1 Phase 1 Transformer installation	N/A	$ 1200.00	Customer charged actual cost for all labour/material
Overhead or underground 3 Phase Transformation required	N/A	$ 3000.00	Customer charged actual cost for all labour/material
Underground 120/240 V 1 Phase 200 A max	N/A	$ 250.00	Customer charged actual cost for all labour/material

NIAGARA-ON-THE-LAKE HYDRO INC.

APPENDIX E

- **Audited Financial Statements at December 31, 2006**

- **Audited Financial Statements at December 31, 2007**

crawford
smith &
swallow

NIAGARA-ON-THE-LAKE HYDRO INC.

Financial Statements

December 31, 2006

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Crawford, Smith and Swallow
Chartered Accountants LLP

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Offices in
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St. Catharines, Ontario
Fort Erie, Ontario
Niagara-on-the-Lake, Ontario
Port Colborne, Ontario

AUDITORS' REPORT

To the Board Members and Shareholder
of Niagara-on-the-Lake Hydro Inc.

We have audited the balance sheet of Niagara-on-the-Lake Hydro Inc. as at December 31, 2006 and the statements of operations, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

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

Crawford, Smith and Swallow

Niagara Falls, Ontario
April 12, 2007

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA-ON-THE-LAKE HYDRO INC.

BALANCE SHEET
December 31, 2006

Assets - notes 6 and 16	2006 $	2005 $
Current Assets		
Cash and cash equivalents	367,582	955,069
Accounts receivable	1,664,793	1,916,762
Unbilled revenue	1,678,572	1,812,641
Due from affiliated companies - note 3	782,490	389,139
Note receivable		298,750
Inventories	200,848	206,640
Prepaid expenses	38,244	66,624
	4,732,529	5,645,625
Property, Plant and Equipment - note 2	19,200,296	18,934,761
Other Assets		
Special deposits	346,623	316,737
Long-term investments - note 5	51,433	48,877
Other assets	3,386	11,600
	401,442	377,214
	24,334,267	**24,957,600**

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

BALANCE SHEET

December 31, 2006

Liabilities and Shareholder's Equity	2006 $	2005 $
Current Liabilities		
Demand instalment loans - note 6	4,628,153	4,878,362
Accounts payable		
Trade	340,617	592,629
Independent Electricity System Operator payable	971,969	1,095,306
Hydro One payable	135,999	184,100
Due to Town of Niagara-on-the-Lake	441,265	187,205
Payments in lieu of corporate taxes payable	279,241	4,905
Other current liabilities	741,252	648,293
	7,538,496	7,590,800
Other Liabilities		
Regulatory liabilities - note 7	1,035,494	1,730,008
Employee future benefits - note 8	451,630	447,634
Customer deposits	346,623	316,737
Accumulated vested sick leave credits	19,361	19,361
Other deposits		39,848
	1,853,108	2,553,588
Long-Term Note Payable - note 9	6,666,333	6,901,333
Contingent Liabilities - notes 10 and 16		
Shareholder's Equity		
Share capital - note 11	2,632,307	2,632,307
Paid-up capital	4,269,026	4,269,026
Retained earnings	1,374,997	1,010,546
	8,276,330	7,911,879
	24,334,267	**24,957,600**

Signed on behalf of the Board:

_______________ Director

_______________ Director

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

STATEMENT OF RETAINED EARNINGS

for the year ended December 31, 2006

	2006 $	2005 $
Retained Earnings, Beginning of Year	1,010,546	578,460
Net Income for the Year	364,451	432,086
Retained Earnings, End of Year	**1,374,997**	**1,010,546**

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

STATEMENT OF OPERATIONS

for the year ended December 31, 2006

	2006 $	2005 $
Service Revenue		
Residential energy	5,718,877	5,342,110
General <50kW energy	2,599,165	2,755,202
General >50kW energy	5,146,647	5,388,650
Street lighting energy	105,580	85,633
Sentinel lighting energy	11,899	8,614
Sales for retailers	990,857	515,630
Non-competitive charges	2,067,994	2,897,159
Transformation services	112,430	148,193
	16,753,449	17,141,191
Cost of Power		
Power purchased	12,591,231	13,363,281
Gross Margin	4,162,218	3,777,910
Other Income		
Administration expense recovery	12,117	4,836
Other revenue	232,259	102,503
Interest income	64,560	(16,341)
	308,936	90,998
	4,471,154	3,868,908
Other Expenditure		
Distribution operations	679,164	550,613
Billing and collection	310,202	297,737
General administration	618,415	583,612
Financial expense	782,766	699,394
Amortization - note 15(a)	1,247,363	1,084,878
	3,637,910	3,216,234
Net Income Before Payments in Lieu of Taxes	833,244	652,674
Payments in Lieu of Taxes	468,793	220,588
Net Income for the Year	**364,451**	**432,086**

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

STATEMENT OF CASH FLOWS
for the year ended December 31, 2006

	2006 $	2005 $
Operating Activities		
Net income for the year	364,451	432,086
Amortization - note 15(a)	1,299,589	1,132,564
Increase in employee future benefits	3,996	15,780
Gain on disposal of property, plant and equipment	(14,849)	(14,535)
Working capital provided by operations	1,653,187	1,565,895
Changes in non-cash working capital components - note 12 (a)	273,305	1,669,882
Funds provided by operating activities	1,926,492	3,235,777
Investing Activities		
Proceeds on disposal of property, plant and equipment	16,626	20,343
Additions to property, plant and equipment - note 12(b)	(1,566,901)	(3,454,427)
Increase (decrease) in regulatory liabilities - note 7	(694,514)	843,224
Increase in special deposits	(29,886)	(102,402)
Increase (decrease) in long-term investment	(2,556)	1,007
Decrease (increase) in other assets	8,214	(11,600)
Funds used by investing activities	(2,269,017)	(2,703,855)
Financing Activities		
Repayment of long-term note payable	(235,000)	
Other Activities		
Increase in customer deposits	29,886	102,402
Decrease in other deposits	(39,848)	
Funds provided (used) by other activities	(9,962)	102,402
Increase (Decrease) in Cash and Cash Equivalents	(587,487)	634,324
Cash and Cash Equivalents, Beginning of Year	955,069	320,745
Cash and Cash Equivalents, End of Year	**367,582**	**955,069**

See accompanying notes

Incorporation

On July 1, 2000, Niagara-on-the-Lake Hydro Inc. was incorporated under the Business Corporations Act (Ontario) along with its affiliate companies, Niagara-on-the-Lake Energy Inc. and Energy Services Niagara Inc. The incorporation was pursuant to the provisions of the Energy Competition Act, 1998.

1. Accounting Policies

These financial statements of Niagara-on-the-Lake Hydro Inc. have been prepared in accordance with Canadian generally accepted accounting principles. The company is a wholly-owned subsidiary of Niagara-on-the-Lake Energy Inc.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 estimates, including changes as a result of future decisions made by the Ontario Energy Board ("OEB") or the Minister of Energy.

Cash and cash equivalents

Cash equivalents are readily convertible investments with maturities of three months or less. Investments are recorded at the lower of cost and market.

Inventories

Inventories are valued at average cost with allowances for obsolete stock.

Property, Plant and Equipment

Property, plant and equipment are stated at cost and removed from the accounts when disposed or retired. Costs of assets which are pooled are removed from the accounts at the end of their estimated average service lives. Gains or losses at retirement or disposition of such assets are credited or charged to other income.

Amortization is provided for property, plant and equipment using the straight-line method based on the following estimated service lives:

Buildings	25 to 50 years
Transformer stations	40 years
Distribution stations	30 years
Distribution lines	25 years
Distribution transformers and meters	25 years
Other capital assets	3 to 15 years
Intangible assets	20 years

Other assets

Expenditures made which may benefit future periods are recorded as other assets. See Regulatory Assets (Liabilities), note 7.

1. Accounting Policies - continued

Investment

The company's investment in a limited liability partnership is accounted for using the equity method. The initial investment is recorded at cost and the carrying value adjusted thereafter to include the pro-rata share of income and losses.

Paid-up capital

Paid-up capital reflects the balance of capital contributions received by the former Niagara-on-the-Lake Hydro-Electric Commission prior to January 1, 2000

Revenue recognition

Service revenue is recorded as revenue in the period to which it relates. Service revenue from the sale of electrical energy includes an estimated accrual for power supplied but not billed to customers from the last meter reading date to the year end.

Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of electricity bills. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability.

Employee future benefits

The company pays certain medical, dental and life insurance benefits on behalf of its retired employees. The company recognizes these post-retirement costs in the period in which the employees rendered the services. The excess of net actuarial gains (losses) over 10% of the actual benefit obligation are amortized over the expected average remaining service life of the active employees. See note 8.

Capitalized interest

The company capitalizes an amount of interest on all funds expended and deferred as regulatory assets/liabilities. See note 15(b).

Payments in lieu of taxes and capital taxes

The company is currently exempt from taxes under the Income Tax Act (Canada) and Ontario Corporations Tax Act.

Under the Electricity Act, 1998, the company is required to make payments in lieu of taxes to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Ontario Corporations Tax Act as modified by the Electricity Act, 1998, and related regulations.

1. Accounting Policies - continued

Payments in lieu of taxes and capital taxes - continued

The company provides for payments in lieu of taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future payments in lieu of 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 payments in lieu of taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Niagara-on-the-Lake Hydro Inc.

2. Property, Plant and Equipment

	Cost $	Accumulated Depreciation $	2006 $	2005 $
Land	310,994		310,994	308,794
Buildings	854,344	269,585	584,759	590,964
Transformer stations	4,996,118	318,267	4,677,851	4,621,039
Distribution stations	242,132	160,698	81,434	87,104
Distribution overhead lines	9,571,091	5,161,820	4,409,271	4,391,008
Distribution underground lines	9,332,170	3,933,403	5,398,767	5,165,505
Distribution transformers	4,907,121	2,448,096	2,459,025	2,364,598
Distribution meters	1,025,826	555,222	470,604	453,678
Equipment and trucks	2,947,538	2,157,265	790,273	933,501
Other	25,038	7,720	17,318	18,570
	34,212,372	**15,012,076**	**19,200,296**	**18,934,761**

3. Due From (To) Affiliated Companies

	2006 $	2005 $
Niagara-on-the-Lake Energy Inc.	(16,383)	22,516
Energy Services Niagara Inc.	798,873	366,623
	782,490	**389,139**

The balance due to Niagara-on-the-Lake Energy Inc. is non-interest bearing with no fixed terms of repayment. The balance due from Energy Services Niagara Inc. bears interest at a variable rate and at year end was prime less 0.5%. Interest charged for the year amounted to $ 43,578.

4. Related Party Transactions

During the period, Niagara-on-the-Lake Hydro Inc. provided operation and administration services to its affiliates in the normal course of business in the following amounts:

	2006 $	2005 $
Energy Services Niagara Inc.	**213,039**	**185,928**

In the ordinary course of business, the company enters into transactions with the Town of Niagara-on-the-Lake (the "Town") including its boards and agencies. The company derives revenues from the sale of electricity and recovers costs of supplying electrical equipment and distribution system from these related parties. Purchases from related parties take place at fair market value. Account balances resulting from these transactions which are included in the balance sheet are settled in accordance with normal trade terms.

5. Long-Term Investments

The company has committed $ 36,000 to a partnership known as the ENERconnect Limited Partnership as a limited partner. This partnership will carry on the business of procuring power on behalf of, and providing services relating to power procurement to limited partners and other third parties who are not.

6. Demand Instalment Loans

	2006 $	2005 $
Demand instalment loan, bearing interest at prime plus 0.75 %, repayable in monthly instalments of $ 15,558 due August, 2008	2,353,531	2,495,796
Demand instalment loan, prime less 0.5 %, repayable in monthly instalments of $ 13,333, due August 2010	2,274,622	2,382,566
	4,628,153	**4,878,362**

The security for the demand instalment loans, bank advances, and letters of credit is a general security agreement, including an assignment of accounts receivable and finished goods and a floating charge over all tangible properties. Under the terms of the credit facility, the company must maintain certain financial covenants and ratios.

6. Demand Instalment Loans - continued

Repayment terms for the demand instalment loans have been negotiated for an amortized period of fifteen years. The principal payments due over the next four years are as follows:

	$
2007	263,858
2008	2,323,748
2009	126,805
2010	1,913,742

7. Regulatory Assets (Liabilities)

The OEB has established in its Electricity Distribution Rate Handbook and its Accounting Procedures Handbook for Electricity Distribution Utilities provisions for recording regulatory assets/liabilities on the company's Balance Sheet.

Regulatory assets/liabilities primarily represent costs that have been deferred in anticipation of future cost recoveries as determined by the OEB. The costs include transition costs to prepare the utility for the competitive electricity market, pre and post market opening settlement variances related to the supply of energy to retailers and standard supply service customers, deferred payments in lieu taxes ("PILS") representing the difference between PILS revenue entitlements and PILS collections and retailer cost variances.

As part of the OEB's 2006 rate application process, the recovery through distribution rates of specific amounts of the company's regulatory asset/liability balances as at December 31, 2004 was approved and is expected to be recovered over a two year period commencing May 1, 2006.

As at December 31, 2006, the company has accumulated $ 1,035,494 ($ 1,730,008 - 2005) in net regulatory liabilities on the balance sheet as other liabilities. It is management's belief that these assets are consistent with the OEB's deferral criteria.

	2006 $	2005 $
Qualifying transition costs		216,694
Pre-market opening variances		162,421
Deferred PILS variances	(100,771)	(52,867)
RSVA & RCVA variances	(185,292)	(670,084)
Other deferred variances		11,797
Regulatory asset recovery	(739,375)	(315,221)
Smart meter recovery	(10,056)	
Deferred charges - HVDS		(1,082,748)
	(1,035,494)	**(1,730,008)**

8. Employee Future Benefits

Defined Benefit Plan Information

	2006 $	2005 $
Employee benefit plan assets		
Employee benefit plan liabilities	463,705	397,324
Employee benefit plan deficit	463,705	397,324
Unamortized actuarial gain (loss)	(12,075)	50,310
Accrued benefit obligation, end of year	**451,630**	**447,634**

	2006 $	2005 $
Accrued benefit obligation, beginning of year	447,634	431,854
Expense for the year	36,234	43,149
Amortization of gain		(1,876)
Benefits paid during the year	(32,238)	(25,493)
Accrued benefit obligation, end of year	**451,630**	**447,634**

An actuarial valuation was last done for the year ending December 31, 2006.

As at December 31, 2006, the actual benefit obligation was $ 463,705 with unamortized loss of $ 12,075. Since the loss is less than 10% of the minimum amortization threshold, no amortization has been recorded.

The main actuarial assumptions employed for the valuation are as follows:

General Inflation - Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2.1% in 2006 and thereafter.

Interest (Discount) Rate - The present value of future liabilities and the expense were determined using discount rates of 5.0%.

Salary Levels - Future general salary and wage levels were assumed to increase at 3.3% per annum.

Medical Costs - Medical costs were assumed to be 6% for 2006, increasing to 11% in 2007 and graded down to 5% in 2013.

Dental Costs - Dental costs were assumed to be 2.5% for 2006, increasing to 5% in 2007 and thereafter.

9. Long-Term Note Payable

On November 1, 2000, Niagara-on-the-Lake Hydro Inc. incurred a long-term note payable to the Town of Niagara-on-the-Lake in the amount of $ 6,901,333. Pursuant to the transfer by-law, the long-term note payable was issued as a non-interest bearing instrument pending the establishment of permanent terms. During the year, the Board approved the repayment of $ 235,000 to the Town. There is no immediate intent to redeem any further amounts of the long-term note payable.

Effective March 1, 2001, interest is payable at 7.25% and amounts paid and accrued for the year amounted to $ 498,927 ($ 500,347 - 2005).

10. Contingent Liability

Class Action

This action has been brought under *Class Proceedings Act*, 1992. The plaintiff class seeks $ 500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDC's") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDC's. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDC's situation may be distinguishable from that of Consumers Gas.

At this time, it is not possible to quantify the effect, if any, on the financial statements of the company. Therefore, no provision has been made in these financial statements with respect to any losses which may arise as a result of this action.

11. Share Capital

Authorized
Unlimited number of common shares

	2006 $	2005 $
Issued		
1,001 common shares	**2,632,307**	**2,632,307**

12. Statement of Cash Flows

(a) Changes in working capital components include:

	2006 $	2005 $
Accounts receivable	251,969	(552,003)
Unbilled revenue	134,069	(158,911)
Due from affiliated companies	(393,351)	(237,044)
Note receivable	298,750	
Inventories	5,792	(52,328)
Prepaid expenses	28,380	583
Demand instalment loans	(250,209)	2,247,602
Accounts payable	(169,390)	304,598
Payments in lieu of taxes payable	274,336	(82,493)
Other current liabilities	92,959	199,878
	273,305	**1,669,882**

(b) Acquisition of capital assets
During the period, capital assets were acquired in the amount of $ 2,565,465. Capital contributions received from third parties amounted to $ 998,564. Cash payments of $ 1,566,901 were made to purchase capital assets.

(c) Interest and payments in lieu of taxes

	2006 $	2005 $
Interest received	**34,323**	**11,523**
Interest paid	**782,766**	**699,275**
Payments in lieu of taxes paid	**226,233**	**303,596**

13. Pension Agreement

The company makes contributions to the Ontario Municipal Employees Retirement Systems ("OMERS"), which is a multi-employer plan, on behalf of approximately 20 members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2006 was $ 68,150 ($ 56,780 - 2005) for current service.

14. General Liability Insurance

The company is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") which is a pooling of general liability insurance risks. Members of MEARIE would be assessed, on a pro-rata basis, based on the total of their respective deposit premiums should losses be experienced by MEARIE, in excess of reserves and supplementary insurance, for the years in which the company or the former Niagara-on-the-Lake Hydro-Electric Commission was a member.

Participation in MEARIE covers a three year underwriting period which expires January 1, 2010. To December 31, 2006, the company has not been made aware of any additional assessments.

15. Other Information

(a) Amortization

	2006 $	2005 $
Amortization of capital assets charged to operations	1,247,363	1,084,878
Amortization of capital assets charged to operating assets	52,226	47,686
	1,299,589	**1,132,564**

(b) Capitalized Interest

	2006 $	2005 $
Capitalized interest	**(95,899)**	**(55,367)**

16. Financial Instruments

Fair Values

The carrying values of cash and bank advances, accounts receivable, accounts payable and accrued liabilities, and client deposits and advances approximate their fair values due to the relatively short periods to maturity of the instruments.

The investment and long-term note payable are stated at face value. It is not practicable within the constraints of timeliness or cost to determine the fair value with sufficient reliability.

Credit Risk

The company in the normal course of business monitors the financial condition of its customers and reviews the credit history of new customers. The company is currently holding customer deposits on hand in the amount of $ 346,623 ($ 316,737 - 2005) and is reflected on the balance sheet. Allowances are also maintained for potential credit losses. Management believes that it has adequately provided for any exposure to normal customer credit risk.

Interest Rate Risk

The demand instalment loans bear interest at floating rates and thus, the carrying values approximates fair values.

However, the company has entered into two swap transactions, the effect of which is to fix the interest rate on the first $ 2,353,531 demand instalment loan at 6.03% and the second $ 2,274,622 demand instalment loan at 5.38% to the maturity date.

The potential replacement cost to Niagara-on-the-Lake Hydro Inc. of the interest rate swap was $ 46,383 which is in favour of CIBC.

Operating Line of Credit

As at December 31, 2006, the company had a line of credit of $ 2,000,000 of which NIL had been drawn down. The line of credit consists of revolving operating and term facilities that bear interest at prime rate minus 0.5% and are secured by all assets of the company. There are unlimited guarantees provided by Niagara-on-the-Lake Energy Inc. and Energy Services Niagara Inc.

Letters of Credit/Guarantees

The company had arranged for a total letter of credit or guarantee in the amount of $ 1,000,000. As at December 31, 2006, $ 857,908 is available to the Independent Electricity System Operator ("IESO") of which NIL had been drawn upon. This is to provide a prudential letter of credit in support of the purchase of electrical power from the IESO. Any draw under this facility will be converted into a capital loan facility with a monthly repayment program to be negotiated.

17. Payments in Lieu of Taxes

Future payments in lieu of income taxes relating to this regulated business have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future payments in lieu of income tax assets of $ 1,425,108 ($ 1,334,166 - 2005), based on substantively enacted income tax rates, have not been recorded. The company was not subject to payments in lieu of taxes prior to October 1, 2001.

Temporary differences and carryforwards which give rise to future payments in lieu of tax assets and liabilities are as follows:

	2006 $	2005 $
Future payments in lieu of tax assets		
Capital assets	1,081,880	1,175,485
Employee future benefits	149,038	161,685
Regulatory liabilities	194,190	(3,004)
	1,425,108	**1,334,166**

The reconciliation of the company's effective income tax rate for payments in lieu of taxes is as follows:

	2006 %	2005 %
Federal income tax rate	22.12	22.12
Provincial income taxes, net of federal abatement	14.00	14.00
Applicable tax rate	36.12	36.12
Capital cost allowance claimed in excess of amortization recorded for income tax purposes	(2.83)	(8.15)
Effect of other items that are deductible for income tax purposes	(0.64)	0.33
Addition for changes in regulatory assets not deductible for tax purposes	23.67	(0.24)
2004 reassessment	(0.05)	5.74
	56.27	**33.80**

18. Comparative Figures

Certain comparative figures have been restated to conform with the current years presentation.

crawford smith & swallow

NIAGARA-ON-THE-LAKE HYDRO INC.

Financial Statements

December 31, 2007

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crawford smith & swallow

AUDITORS' REPORT

To the Board Members and Shareholder
of Niagara-on-the-Lake Hydro Inc.

We have audited the balance sheet of Niagara-on-the-Lake Hydro Inc. as at December 31, 2007 and the statements of operations, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Crawford, Smith and Swallow

Niagara Falls, Ontario
March 19, 2008

CRAWFORD, SMITH AND SWALLOW
CHARTERED ACCOUNTANTS LLP

LICENSED PUBLIC ACCOUNTANTS

NIAGARA-ON-THE-LAKE HYDRO INC.

BALANCE SHEET
December 31, 2007

Assets - notes 7 and 17	2007 $	2006 $
Current Assets		
Cash and cash equivalents	202,358	367,582
Accounts receivable	1,846,952	1,664,793
Unbilled revenue	1,683,427	1,678,572
Payments in lieu of corporate income taxes receivable	208,575	
Due from affiliated companies - note 4	955,941	782,490
Inventories	205,646	200,848
Prepaid expenses	32,835	38,244
	5,135,734	4,732,529
Property, Plant and Equipment - note 3	19,251,754	19,200,296
Other Assets		
Special deposits	361,117	346,623
Long-term investments - note 6		51,433
Other assets	8,208	3,386
	369,325	401,442
	24,756,813	**24,334,267**

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

BALANCE SHEET
December 31, 2007

Liabilities and Shareholder's Equity	2007 $	2006 $
Current Liabilities		
Demand instalment loans - note 7	4,376,767	4,628,153
Accounts payable		
Trade	602,959	340,617
Independent Electricity System Operator payable	1,029,596	971,969
Hydro One payable	219,076	135,999
Due to Town of Niagara-on-the-Lake	553,056	441,265
Payments in lieu of corporate income taxes payable		279,241
Other current liabilities	763,279	741,252
	7,544,733	7,538,496
Other Liabilities		
Regulatory liabilities - note 8	676,889	1,035,494
Employee future benefits - note 9	452,510	451,630
Customer deposits	361,117	346,623
Accumulated vested sick leave credits	19,361	19,361
	1,509,877	1,853,108
Long-Term Note Payable - note 10	6,566,333	6,666,333
Contingent Liabilities - notes 11 and 17		
Shareholder's Equity		
Share capital - note 12	2,632,307	2,632,307
Paid-up capital	4,269,026	4,269,026
Retained earnings	2,234,537	1,374,997
	9,135,870	8,276,330
	24,756,813	**24,334,267**

Signed on behalf of the Board:

______________ Director

______________ Director

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

STATEMENT OF RETAINED EARNINGS

for the year ended December 31, 2007

	2007 $	2006 $
Retained Earnings, Beginning of Year	1,374,997	1,010,546
Accounting Change - note 2	(46,383)	
Retained Earnings, Beginning of Period as Restated	1,328,614	1,010,546
Net Income for the Year	905,923	364,451
Retained Earnings, End of Year	**2,234,537**	**1,374,997**

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

STATEMENT OF OPERATIONS

for the year ended December 31, 2007

	2007 $	2006 $
Service Revenue		
Residential energy	5,803,560	5,718,877
General <50kW energy	3,006,383	2,599,165
General >50kW energy	4,580,346	5,146,647
Street lighting energy	91,381	105,580
Sentinel lighting energy	8,720	11,899
Sales for retailers	1,776,801	990,857
Non-competitive charges	2,424,079	2,067,994
Transformation services		112,430
	17,691,270	16,753,449
Cost of Power		
Power purchased	13,081,768	12,591,231
Gross Margin	4,609,502	4,162,218
Other Income		
Administration expense recovery	24,918	12,117
Other revenue	198,913	232,259
Interest income	62,539	64,560
	286,370	308,936
	4,895,872	4,471,154
Other Expenditure		
Distribution operations	782,943	679,164
Billing and collection	355,606	310,202
General administration	639,048	618,415
Financial expense	759,213	782,766
Amortization - note 16(a)	1,241,397	1,247,363
	3,778,207	3,637,910
Net Income Before Payments in Lieu of Corporate Income Taxes	1,117,665	833,244
Payments in Lieu of Corporate Income Taxes	211,742	468,793
Net Income for the Year	**905,923**	**364,451**

See accompanying notes

NIAGARA-ON-THE-LAKE HYDRO INC.

STATEMENT OF CASH FLOWS

for the year ended December 31, 2007

	2007 $	2006 $
Operating Activities		
Net income for the year	905,923	364,451
Amortization - note 16(a)	1,306,540	1,299,589
Increase in employee future benefits	880	3,996
Gain on disposal of property, plant and equipment	(24,515)	(14,849)
Loss on disposal of long-term investment	44,046	
Retained earnings adjustment related to fair value hedge - note 2	(46,383)	
Working capital provided by operations	2,186,491	1,653,187
Changes in non-cash working capital components - note 13 (a)	(562,192)	273,305
Funds provided by operating activities	1,624,299	1,926,492
Investing Activities		
Proceeds on disposal of property, plant and equipment	33,480	16,626
Proceeds on disposal of long term investment	7,387	
Additions to property, plant and equipment - note 13(b)	(1,366,963)	(1,566,901)
Decrease in regulatory liabilities - note 8	(358,605)	(694,514)
Increase in special deposits	(14,494)	(29,886)
Increase in long-term investment		(2,556)
Increase in other assets	(4,822)	8,214
Funds used by investing activities	(1,704,017)	(2,269,017)
Financing Activities		
Repayment of long-term note payable	(100,000)	(235,000)
Other Activities		
Increase in customer deposits	14,494	29,886
Decrease in other deposits		(39,848)
Funds provided (used) by other activities	14,494	(9,962)
Decrease in Cash and Cash Equivalents	(165,224)	(587,487)
Cash and Cash Equivalents, Beginning of Year	367,582	955,069
Cash and Cash Equivalents, End of Year	**202,358**	**367,582**

See accompanying notes

Incorporation

On July 1, 2000, Niagara-on-the-Lake Hydro Inc. was incorporated under the Business Corporations Act (Ontario) along with its affiliate companies, Niagara-on-the-Lake Energy Inc. and Energy Services Niagara Inc. The incorporation was pursuant to the provisions of the Energy Competition Act, 1998.

1. Accounting Policies

These financial statements of Niagara-on-the-Lake Hydro Inc. have been prepared in accordance with Canadian generally accepted accounting principles. The company is a wholly-owned subsidiary of Niagara-on-the-Lake Energy Inc.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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 estimates, including changes as a result of future decisions made by the Ontario Energy Board ("OEB") or the Minister of Energy.

Cash and cash equivalents

Cash equivalents are readily convertible investments with maturities of three months or less.

Inventories

Inventories are valued at average cost with allowances for obsolete stock.

Property, Plant and Equipment

Property, plant and equipment are stated at cost and removed from the accounts when disposed or retired. Costs of assets which are pooled are removed from the accounts at the end of their estimated average service lives. Gains or losses at retirement or disposition of such assets are credited or charged to other income.

Amortization is provided for property, plant and equipment using the straight-line method based on the following estimated service lives:

Buildings	25 to 50 years
Transformer stations	40 years
Distribution stations	30 years
Distribution lines	25 years
Distribution transformers and meters	25 years
Other capital assets	3 to 15 years
Intangible assets	20 years

Other assets

Expenditures made which may benefit future periods are recorded as other assets.

1. Accounting Policies - continued

Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of electricity bills. Deposits expected to be refunded to customers within the next fiscal period are classified as a current liability.

Employee future benefits

The company pays certain medical, dental and life insurance benefits on behalf of its retired employees. The company recognizes these post-retirement costs in the period in which the employees rendered the services. The excess of net actuarial gains (losses) over 10% of the actual benefit obligation are amortized over the expected average remaining service life of the active employees. See note 9.

Paid-up capital

Paid-up capital reflects the balance of capital contributions received by the former Niagara-on-the-Lake Hydro-Electric Commission prior to January 1, 2000

Revenue recognition

Service revenue is recorded as revenue in the period to which it relates. Service revenue from the sale of electrical energy includes an estimated accrual for power supplied but not billed to customers from the last meter reading date to the year end.

Capitalized interest

The company capitalizes an amount of interest on all funds expended and deferred as regulatory assets/liabilities. See note 16(b).

Payments in lieu of corporate income taxes and capital taxes

The company is currently exempt from corporate income taxes under the Income Tax Act (Canada) and Ontario Corporations Tax Act.

Under the Electricity Act, 1998, the company is required to make payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Ontario Corporations Tax Act as modified by the Electricity Act, 1998, and related regulations.

The company provides for payments in lieu of corporate income taxes using the taxes payable method. Under the taxes payable method, no provisions are made for future payments in lieu of corporate 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 payments in lieu of corporate 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 Niagara-on-the-Lake Hydro Inc.

2. Accounting Change

Financial Instruments - Recognition and Measurement, Financial Instruments - Disclosure and Presentation and Hedges. These new standards prescribe when a financial instrument is to be recognized and derecognized from the balance sheet and at what amount these financial instruments should be recognized. It also specifies how financial instrument gains and losses are accounted for. Under these new standards, all financial assets are classified as held-for-trading, held-to-maturity, loans and receivables or available-for-sale and all financial liabilities must be classified as held-for-trading or other financial liabilities. In addition, an entity has the option to designate financial assets or liabilities as held-for-trading or financial assets as available-for-sale on initial recognition or upon adoption of those standards, even if the financial instrument was not acquired or incurred for the purpose of selling or repurchasing it in the near term.

All financial instruments are required to be measured at fair value on initial recognition except for certain related party transactions. After initial recognition, financial instruments should be measured at their fair values, except for financial assets classified as held-to-maturity or loans and receivables and other financial liabilities, which are measured at cost or amortized cost using the effective interest method. Financial assets classified as available-for-sale that do not have a quoted market price in an active market are measured at cost. Amortization related to financial assets classified as held-to-maturity or loans and receivables and other financial liabilities and unrealized gains and losses related to financial assets and liabilities classified as held-for-trading are recorded in net income for the period in which it arises. If a financial asset is classified as available-for-sale, the cumulative unrealized gain or loss is recognized in accumulated other comprehensive income and recognized in income upon the sale or other-than-temporary impairment.

The Company has adopted the following classification for financial assets and financial liabilities:

-Cash and cash equivalents are classified as held-for-trading.

-Accounts and other receivables, other assets are classified as loans and receivables.

-Demand instalment loans, accounts payable and other accrued liabilities, regulatory liabilities, customer deposits, accumulated sick leave credits and long-term note payable are classified as other financial liabilities.

The new standards require all derivative financial instruments to be measured at fair value on the balance sheet, even when they are part of an effective hedging relationship. An embedded derivative is a component of a hybrid instrument that also includes a non-derivative host contract, with the effect that some of the cash flows of the combined instrument vary in a way similar to a stand-alone derivative. If certain conditions are met, an embedded derivative is separated from the host contract and accounted for as a derivative in the balance sheet and measured at fair value. Upon adoption, entities have the option to recognize as an asset or liability all embedded derivative instruments that are required to be separated from their host contracts. The Company does not have any material outstanding contracts or financial instruments with embedded derivatives that require bifurcation.

2. Accounting Change - continued

Hedge accounting is used for designated derivatives provided certain criteria are met. Fair value derivatives related to the demand instalment loans that qualify for hedge accounting are accounted for at fair value with changes in fair value in other revenue on the statement of operations.

As at January 1, 2007, an opening fair value loss of $ 46,383 was recorded on a retroactive basis without restatement of prior year retained earnings. For the year ending December 31, 2007, a fair value gain of $ 33,911 was recorded in other revenue.

3. Property, Plant and Equipment

	Cost $	Accumulated Depreciation $	2007 $	2006 $
Land	310,994		310,994	310,994
Buildings	896,794	284,719	612,075	584,759
Transformer stations	5,181,654	445,489	4,736,165	4,677,851
Distribution stations	242,132	166,368	75,764	81,434
Distribution overhead lines	9,857,677	5,471,706	4,385,971	4,409,271
Distribution underground lines	9,586,277	4,299,898	5,286,379	5,398,767
Distribution transformers	5,065,929	2,597,870	2,468,059	2,459,025
Distribution meters	1,032,194	581,044	451,150	470,604
Equipment and trucks	3,067,765	2,158,634	909,131	790,273
Other	25,038	8,972	16,066	17,318
	35,266,454	**16,014,700**	**19,251,754**	**19,200,296**

4. Due From (To) Affiliated Companies

	2007 $	2006 $
Niagara-on-the-Lake Energy Inc.	21,110	(16,383)
Energy Services Niagara Inc.	934,831	798,873
	955,941	**782,490**

The balance due to Niagara-on-the-Lake Energy Inc. is non-interest bearing with no fixed terms of repayment. The balance due from Energy Services Niagara Inc. bears interest at a variable rate and at year end was prime less 0.5%. Interest charged for the year amounted to $ 46,121.

5. Related Party Transactions

During the period, Niagara-on-the-Lake Hydro Inc. provided operation and administration services to its affiliates in the normal course of business in the following amounts:

	2007 $	2006 $
Energy Services Niagara Inc.	**239,204**	**213,039**

In the ordinary course of business, the company enters into transactions with the Town of Niagara-on-the-Lake (the "Town") including its boards and agencies. The company derives revenues from the sale of electricity and recovers costs of supplying electrical equipment and distribution system from these related parties. Purchases from related parties take place at fair market value. Account balances resulting from these transactions which are included in the balance sheet are settled in accordance with normal trade terms.

6. Long-Term Investments

Effective December 31, 2007, the company has disposed of its partnership interest known as the ENERconnect Limited Partnership.

7. Demand Instalment Loans

	2007 $	2006 $
Demand instalment loan, bearing interest at prime plus 0.75 %, repayable in monthly instalments of $ 15,558 due August, 2008	2,222,340	2,353,531
Demand instalment loan, prime less 0.5 %, repayable in monthly instalments of $ 13,333, due August 2010	2,154,427	2,274,622
	4,376,767	**4,628,153**

The security for the demand instalment loans, bank advances, and letters of credit is a general security agreement, including an assignment of accounts receivable and finished goods and a floating charge over all tangible properties. Under the terms of the credit facility, the company must maintain certain financial covenants and ratios.

7. Demand Instalment Loans - continued

Repayment terms for the demand instalment loans have been negotiated for an amortized period of fifteen years. The principal payments due over the next three years are as follows:

	$
2008	2,342,518
2009	126,805
2010	1,907,444

8. Regulatory Liabilities

The OEB has established in its Electricity Distribution Rate Handbook and its Accounting Procedures Handbook for Electricity Distribution Utilities provisions for recording deferral and variance account regulatory assets or liabilities on the company's balance sheet.

Deferral and variance account regulatory liabilities primarily represent costs that have been deferred in anticipation of future cost recoveries as determined by the OEB. The costs include transition costs to prepare the utility for the competitive electricity market, pre and post market opening settlement variances related to the supply of energy to retailers and standard supply service customers, deferred payments in lieu taxes ("PILS") representing the difference between PILS revenue entitlements and PILS collections and retailer cost variances.

As part of the OEB's 2006 rate application process, the recovery through distribution rates of specific amounts of the company's deferral and variance account regulatory liability balances as at December 31, 2004 was approved and is expected to be recovered as "regulatory asset" recoveries over a two year period commencing May 1, 2006.

As at December 31, 2007, the company has accumulated $ 676,889 ($ 1,035,494 - 2006) in net regulatory liabilities on the balance sheet as other liabilities. It is management's belief that these assets are consistent with the OEB's deferral criteria.

	2007 $	2006 $
Deferred PILS variances	(104,908)	(100,771)
RSVA & RCVA variances	(72,564)	(185,292)
Regulatory asset (liabilities) recovery	(488,640)	(739,375)
Smart meter recovery	(10,777)	(10,056)
	(676,889)	**(1,035,494)**

9. Employee Future Benefits

Defined Benefit Plan Information

	2007 $	2006 $
Employee benefit plan assets		
Employee benefit plan liabilities	464,585	463,705
Employee benefit plan deficit	464,585	463,705
Unamortized actuarial loss	(12,075)	(12,075)
Accrued benefit obligation, end of year	**452,510**	**451,630**

	2007 $	2006 $
Accrued benefit obligation, beginning of year	451,630	447,634
Expense for the year	37,038	36,234
Amortization of loss		
Benefits paid during the year	(36,158)	(32,238)
Accrued benefit obligation, end of year	**452,510**	**451,630**

An actuarial valuation was last done for the year ending December 31, 2006.

As at December 31, 2007, the actual benefit obligation was $ 464,585 with unamortized loss of $ 12,075. Since the loss is less than 10% of the minimum amortization threshold, no amortization has been recorded.

The main actuarial assumptions employed for the valuation are as follows:

General Inflation - Future general inflation levels, as measured by changes in the Consumer Price Index (CPI), were assumed at 2.1% in 2006 and thereafter.

Interest (Discount) Rate - The present value of future liabilities and the expense were determined using discount rates of 5.0%.

Salary Levels - Future general salary and wage levels were assumed to increase at 3.3% per annum.

Medical Costs - Medical costs were assumed to be 6% for 2006, increasing to 11% in 2007 and graded down to 5% in 2013.

Dental Costs - Dental costs were assumed to be 2.5% for 2006, increasing to 5% in 2007 and thereafter.

10. Long-Term Note Payable

Long-term note payable to the Town of Niagara-on-the-Lake, interest is payable at 7.25% and amounts paid and accrued for the year amounted to $ 483,309 ($ 498,927 - 2006). During the year, the Board approved the repayment of $ 100,000 ($ 235,000 - 2006) to the Town. There are no fixed terms of repayment.

11. Contingent Liabilities

Class Action

This action has been brought under *Class Proceedings Act*, 1992. The plaintiff class seeks $ 500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDC's") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008 the OEB approved recovery of said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDC's. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDC's situation may be distinguishable from that of Consumers Gas.

At this time, it is not possible to quantify the effect, if any, on the financial statements of the company. Therefore, no provision has been made in these financial statements with respect to any losses which may arise as a result of this action.

Legal Claim

The company is in litigation pertaining to a certain claim for which the likelihood of loss is not determinable and the amount not reasonably estimable. Accordingly, no provision for this claim is reflected in the financial statements.

12. Share Capital

Authorized
Unlimited number of common shares

	2007 $	2006 $
Issued		
1,001 common shares	**2,632,307**	**2,632,307**

13. Statement of Cash Flows

(a) Changes in working capital components include:

	2007 $	2006 $
Accounts receivable	(182,159)	251,969
Unbilled revenue	(4,855)	134,069
Due from affiliated companies	(173,451)	(393,351)
Note receivable		298,750
Inventories	(4,798)	5,792
Prepaid expenses	5,409	28,380
Demand instalment loans	(251,386)	(250,209)
Accounts payable	514,837	(169,390)
Payments in lieu of taxes payable	(487,816)	274,336
Other current liabilities	22,027	92,959
	(562,192)	**273,305**

(b) Acquisition of capital assets

During the period, capital assets were acquired in the amount of $ 1,671,659. Capital contributions received from third parties amounted to $ 304,696. Cash payments of $ 1,366,963 were made to purchase capital assets.

(c) Interest and payments in lieu of taxes

	2007 $	2006 $
Interest received	**24,640**	**34,323**
Interest paid	**551,761**	**782,766**
Payments in lieu of taxes paid	**699,558**	**226,233**

14. Pension Agreement

The company makes contributions to the Ontario Municipal Employees Retirement Systems ("OMERS"), which is a multi-employer plan, on behalf of approximately 17 members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay.

The amount contributed to OMERS for 2007 was $ 71,522 ($ 68,150 - 2006) for current service.

15. General Liability Insurance

The company is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") which is a pooling of general liability insurance risks. Members of MEARIE would be assessed, on a pro-rata basis, based on the total of their respective deposit premiums should losses be experienced by MEARIE, in excess of reserves and supplementary insurance, for the years in which the company or the former Niagara-on-the-Lake Hydro-Electric Commission was a member.

Participation in MEARIE covers a three year underwriting period which expires January 1, 2010. To December 31, 2007, the company has not been made aware of any additional assessments.

16. Other Information

(a) Amortization

	2007 $	2006 $
Amortization of capital assets charged to operations	1,241,397	1,247,363
Amortization of capital assets charged to operating assets	65,143	52,226
	1,306,540	**1,299,589**

(b) Capitalized Interest

	2007 $	2006 $
Capitalized interest	**5,104**	**(95,899)**

17. Financial Instruments

Fair Values

The carrying values of cash and bank advances, accounts receivable, accounts payable and accrued liabilities, and client deposits and advances approximate their fair values due to the relatively short periods to maturity of the instruments.

The long-term note payable is stated at face value. It is not practicable within the constraints of timeliness or cost to determine the fair value with sufficient reliability.

Credit Risk

The company in the normal course of business monitors the financial condition of its customers and reviews the credit history of new customers. The company is currently holding customer deposits on hand in the amount of $ 361,117 ($ 346,623 - 2006) and is reflected on the balance sheet. Allowances are also maintained for potential credit losses. Management believes that it has adequately provided for any exposure to normal customer credit risk.

Interest Rate Risk

The demand instalment loans bear interest at floating rates and thus, the carrying values approximates fair values.

However, the company has entered into two fair value swap transactions, the effect of which is to fix the interest rate on the first $ 2,222,340 demand instalment loan at 6.03% and the second $ 2,154,427 demand instalment loan at 5.38% to the maturity date.

Operating Line of Credit

As at December 31, 2007, the company had a line of credit of $ 2,000,000 of which NIL had been drawn down. The line of credit consists of revolving operating and term facilities that bear interest at prime rate minus 0.5% and are secured by all assets of the company. There are unlimited guarantees provided by Niagara-on-the-Lake Energy Inc. and Energy Services Niagara Inc.

Letters of Credit/Guarantees

The company had arranged for a total letter of credit or guarantee in the amount of $ 1,000,000. As at December 31, 2007, $ 857,908 is available to the Independent Electricity System Operator ("IESO") of which NIL had been drawn upon. This is to provide a prudential letter of credit in support of the purchase of electrical power from the IESO. Any draw under this facility will be converted into a capital loan facility with a monthly repayment program to be negotiated.

18. Payments in Lieu of Taxes

Future payments in lieu of income taxes relating to this regulated business have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future payments in lieu of income tax assets of $ 1,142,439 ($ 1,425,108 - 2006), based on substantively enacted income tax rates, have not been recorded. The company was not subject to payments in lieu of taxes prior to October 1, 2001.

Temporary differences and carryforwards which give rise to future payments in lieu of tax assets and liabilities are as follows:

	2007 $	2006 $
Future payments in lieu of tax assets		
Capital assets	932,026	1,081,880
Employee future benefits	131,228	149,038
Regulatory liabilities	79,185	194,190
	1,142,439	**1,425,108**

The reconciliation of the company's effective income tax rate for payments in lieu of taxes is as follows:

	2007 %	2006 %
Federal income tax rate	22.12	22.12
Provincial income taxes, net of federal abatement	14.00	14.00
Applicable tax rate	36.12	36.12
Provincial small business deduction	(1.66)	
Capital cost allowance claimed in excess of amortization recorded for income tax purposes	(2.82)	(2.83)
Effect of other items that are deductible for income tax purposes	(0.77)	0.43
Addition for changes in regulatory assets not deductible for tax purposes	(9.74)	23.67
Loss (gain) on disposal of assets	0.63	(0.64)
Federal apprenticeship tax credit	(0.09)	(0.24)
Provincial apprenticeship and co-operative education tax credits	(0.24)	(0.28)
Other	(2.49)	0.03
	18.94	**56.26**

19. Asset Retirement Obligations

The company has identified asset retirement obligations relating to future site remediation costs for five different distribution stations in the Niagara-on-the-Lake area. Once a site has been decommissioned, it will require remediation prior to sale. At this time, some of the sites have been decommissioned and therefore require remediation. However, since the remediation will not be done until the site is put up for sale, sufficient information is not available at this time to determine the fair value of the remediation costs. The liability will be recognized in the period that sufficient information exists to make a reasonably accurate estimate of the amount.

Filed: August 7, 2008

NIAGARA-ON-THE-LAKE HYDRO INC.

APPENDIX F

- **Federal T2 Tax Return, 2007**

- **Ontario CT23 Tax Return, 2007**

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide* (T4012).

Identification

Business Number (BN) 001 86360 5929 RC0001

Corporation's name

002 NIAGARA-ON-THE-LAKE HYDRO INC.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? *(Do not submit)* . . . . . 004 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 P.O. Box 460

012 8 Henegan Road

City: 015 Virgil

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 L0S 1T0

To which tax year does this return apply?

Tax year start: 060 2007-01-01 (YYYY MM DD)

Tax year-end: 061 2007-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ____ (YYYY MM DD)

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028)

021 c/o

022

023

City: 025

Province, territory, or state: 026

Country (other than Canada): 027

Postal code/Zip code: 028

Is this the first year of filing after:

Incorporation? . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038)

031 P.O. BOX 460,

032 8 HENEGAN ROAD

City: 035 Virgil

Province, territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 L0S 1T0

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and **complete and attach** Schedule 97.

081

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ____ (YYYY MM DD)

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

PLEASE KEEP FOR REFERENCE

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177

Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

* We do not print this schedule.

Additional information

		1 Yes	2 No
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? 282 ____
(Only complete if **yes** was entered at line 281)

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale [ ] 2 Retail [ ]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Distribut	285	99.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		731,167	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			731,167	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		731,167	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			731,167	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . **400** 731,167 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . **405** 731,167 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000	x	Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year	/ 365	=		1
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	365 / 365	=	400,000	2
				Add amounts at lines 1 and 2	400,000	4

Business limit (see notes 1 and 2 below) . . . **410** 400,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 x **415** *** 21,490 D / 11,250 = . . . 764,089 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . **425** ______ F

Small business deduction

Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	16 %	= ______	5
Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	17 %	= ______	6
Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year after December 31, 2008 / Number of days in the tax year	/ 365	x	17 %	= ______	7

Total of amounts 5, 6, and 7 – enter on line 9 **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . **435** ______ H

Amount H	______	x	Number of days in the tax year in 2005 / Number of days in the tax year	/ 365	x	3 %	= ______	I
Amount H	______	x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 365	x	5 %	= ______	J
Amount H	______	x	Number of days in the tax year in 2007 / Number of days in the tax year	365 / 365	x	7 %	= ______	K

Resource deduction – total of amounts I, J and K . . . **438** ______ L
Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		731,167	A
Amount Z1 from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Taxable resource income from line 435		D	
Amount used to calculate the credit union deduction (from Schedule 17)		E	
Amount from line 400, 405, 410, or 425, whichever is the least		F	
Aggregate investment income from line 440		G	
Total of amounts B, C, D, E, F, and G	▶		H
Amount A **minus** amount H (if negative, enter "0")		731,167	I

Amount I	731,167	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x 7 %	= 51,182	J
Amount I	731,167	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	K
Amount I	731,167	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x 9 %	=	K1
Amount I	731,167	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x 10 %	=	K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 ..... 51,182 L
Enter amount L on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			M
Amount Z1 from Part 9 of Schedule 27		N	
Amount QQ from Part 13 of Schedule 27		O	
Taxable resource income from line 435		P	
Amount used to calculate the credit union deduction (from Schedule 17)		Q	
Total of amounts N, O, P, and Q	▶		R
Amount M **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x 7 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x 8.5 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x 9 %	=	U1
Amount S		x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x 10 %	=	U2

General tax reduction – total of amounts T, U, U1, and U2 V
Enter amount V on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	440		x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632					
Deduct:					
Foreign investment income (from Schedule 7)	445		x 9 1 / 3 % =		
			(if negative, enter "0")		B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			731,167		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least					
Foreign non-business income tax credit from line 632		x 25 / 9 =			
Foreign business income tax credit from line 636		x 3 =			
			731,167		
			x 26 2 / 3 % =	194,978	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			160,047		
Deduct: Corporate surtax from line 600			8,189		
Net amount			151,858	151,858	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least	450				F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
				G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
				H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3		x 1 / 3		I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied by** 38.00 % . . . . **550** 277,843 A

Corporate surtax calculation

Base amount from line A above	277,843	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	73,117	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6	73,117	7
Net amount (line 1 **minus** line 7)	204,726	8

Corporate surtax*

Line 8 204,726 x $\frac{\text{Number of days in the tax year before January 1, 2008} \quad 365}{\text{Number of days in the tax year} \quad 365}$ x 4 % = **600** 8,189 B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . **602** ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	731,167		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	731,167 ▶	731,167	ii

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount i or ii . . . . . **604** ______ D

Subtotal (**add** lines A, B, C, and D) 286,032 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	**608**	73,117	
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction	**620**		
(taxed capital gains **624** ______)			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount L	**638**	51,182	
General tax reduction from amount V	**639**		
Federal logging tax credit from Schedule 21	**640**		
Federal political contribution tax credit	**644**		
Federal political contributions **646** ______			
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**	1,686	
Subtotal		125,985 ▶	125,985 F

Part I tax payable – Line E **minus** line F . . . . . 160,047 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	160,047
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		160,047

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		160,047 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	160,047	
Total credits	890	160,047	160,047 B

Refund code 894 ______ Overpayment ______

Balance (line A **minus** line B) ______

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of \$2 or less.

Balance unpaid ______

Enclosed payment 898 ______

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 WORMWELL (Last name in block letters) 951 PHILIP (First name in block letters) 954 DIRECTOR OF CORPORATE SERVICES (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-05-12 (Date (yyyy/mm/dd))

______ Signature of the authorized signing officer of the corporation

956 (905) 468-4235 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 ______ Name in block letters

959 ______ Telephone number

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

1 English / Anglais ☒ 2 Français / French ☐

Schedule of Instalment Remittances

Name of corporation contact: Mr. Philip Wormwell
Telephone number: (905) 468-4235

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
		160,047
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	160,047 A
	Total instalments credited to the taxation year per T9	160,047 B

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				905,922 A
Add:				
Provision for income taxes – current		101	211,742	
Interest and penalties on taxes		103	9,387	
Amortization of tangible assets		104	1,306,540	
Loss on disposal of assets		111	19,531	
Subtotal of additions			1,547,200 ►	1,547,200
Other additions:				
Miscellaneous other additions:				
600 2006 Federal apprenticeship credit		290	2,000	
601 Change in employee future benefits		291	880	
603.2 Ontario Specified Tax Credits	4,112			
Total	4,112	293	4,112	
Subtotal of other additions		199	6,992 ►	6,992
Total additions		500	1,554,192 ►	1,554,192
Deduct:				
Capital cost allowance from Schedule 8		403	1,392,642	
Cumulative eligible capital deduction from Schedule 10		405	1,143	
Subtotal of deductions			1,393,785 ►	1,393,785
Other deductions:				
Miscellaneous other deductions:				
700 Change in regulatory assets		390	301,251	
701 Unrealized gains on financial instruments		391	33,911	
Total		394		
Subtotal of other deductions		499	335,162 ►	335,162
Total deductions		510	1,728,947 ►	1,728,947
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				731,167

* For reference purposes only

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SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

- This form is used to determine the continuity and use of available losses; to determine the current-year non-capital loss, farm loss, restricted farm loss, and limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that may be applied in a year; and to request a loss carryback to previous years.
- The corporation can choose whether or not to deduct an available loss from income in a tax year. It can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time and no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send it by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the *Income Tax Act.*

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		731,167
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)		
Taxable dividends deductible under sections 112, 113, or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		
Deduct: (increase a loss) — Subtotal (if positive, enter "0")		
Section 110.5 and/or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions		
Add: (decrease a loss) — Subtotal		
Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		

Continuity of non-capital losses and request for a carryback

	Line		
Non-capital loss at the end of the previous tax year			
Deduct: Non-capital loss expired *	100		
Non-capital losses at the beginning of the tax year	102		
Add: Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Deduct:			
Amount applied against taxable income (enter on line 331 of the T2 return)	130		
Amount applied against taxable dividends subject to Part IV tax	135		
Subtotal			
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		
Non-capital losses – Closing balance	180		

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator	190	Yes

Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately previous tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	23,386		
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205			23,386
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Add:			Subtotal	23,386
Current-year capital loss (from the calculation on Schedule 6)			210	32,965
Unused non-capital losses that expired in the tax year*		A		
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**		B		
Enter amount from line A or B, whichever is less	215			
ABILs expired as non-capital loss: line 215 divided by the inclusion rate*** 75.0000 %			220	
			Subtotal	56,351

Note: If there has been an amalgamation or a wind-up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total at line 220 above.

Deduct: Amount applied against the current-year capital gain (see Note 1)			225	
			Subtotal	56,351

Deduct – Request to carry back capital loss to (see Note 2):

	Capital gain (100%)		Amount carried back (100%)
First previous tax year		951	
Second previous tax year		952	
Third previous tax year		953	

Capital losses – Closing balance	280	56,351

Note 1
Enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2
On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			
Deduct: Farm loss expired *	300		
Farm losses at the beginning of the tax year	302		
Add: Farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance	380		

* A farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business .... **485** ______ C

Minus the deductible farm loss:

$2,500 plus D or E, whichever is less .... $ 2,500

(Amount C above ______ – $2,500) divided by 2 = ______ D

$ 6,250 E ______ 2,500 F

Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410) .... ______

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired *	400		
Restricted farm losses at the beginning of the tax year	402		
Add: Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
Restricted farm losses – Closing balance	480		

Note
The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year				
Deduct: Listed personal property loss expired after seven tax years			500	
Listed personal property losses at the beginning of the tax year			502	
Add: Current-year listed personal property loss (from Schedule 6)			510	
			Subtotal	
Deduct:				
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530			
Other adjustments	550			
			Subtotal	
Deduct – Request to carry back listed personal property loss to:				
First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Listed personal property losses – Closing balance			580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 - 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year. (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

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SCHEDULE 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss, or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act*, if the control of the corporation has been acquired by a person or group of persons.

For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*
Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?
050 1 Yes [ ] 2 No [X] If *Yes*, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

	No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 less cols. 130 and 140) 150	Foreign source
1									
				Totals					A

Part 2 – Real estate – Do not include losses on depreciable property

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 less cols. 230 and 240) 250	Foreign source
1							
		Totals					B

Part 3 – Bonds

	Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 less cols. 330 and 340) 350	Foreign source
1									
				Totals					C

Part 4 – Other properties – Do not include losses on depreciable property

	Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 less cols. 430 and 440) 450	Foreign source
1	ENERConnect Partnership Interest	1999-01-01	18,468	51,433		-32,965	
2							
		Totals	18,468	51,433		-32,965	D

Part 5 – Personal-use property (Do not include listed personal property)

	Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 less cols. 530 and 540) 550	Foreign source
1							
	Note: Losses are not deductible.	Totals					E

Part 6 – Listed personal property

	Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 less cols. 630 and 640) 650	Foreign source
1							
		Totals					

Note: Net listed personal property losses may only be applied against listed personal property gains.

Subtract: Unapplied listed personal property losses from other years 655 ______

Amount from line 655 is from line 530 in Part 5 of Schedule 4.

Net gains (or losses) ______ F

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

	Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	(Loss)(column 920 less cols. 930 and 940) 950	Foreign source
1								
	Note: Properties listed in Part 7 should not be included in any other parts of Schedule 6.		Totals					G

Allowable business investment losses . . . . Amount G ______ x 50 % = ______ H

Enter amount H on line 406 of Schedule 1.

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss)		-32,965	I
Add:			Foreign source
Capital gains dividend received in the year	875		J
Capital gains reserve opening balance (from Schedule 13)	880		K
Subtotal (add amounts I, J, and K)		-32,965	L
Deduct: Capital gains reserve closing balance (from Schedule 13)	885		M
Capital gains or losses (amount L minus amount M)	890	-32,965	

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above)					-32,965	N
Deduct the following gains that are included in the amount N:						
Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the *Income Tax Act*						
realized prior to May 2, 2006		x 50 % =		O		Foreign source ☐
realized after May 1, 2006				P		Foreign source ☐
Subtotal: O plus P			895			
Gain on donation of ecologically sensitive land						
realized prior to May 2, 2006		x 50 % =		Q		Foreign source ☐
realized after May 1, 2006				R		Foreign source ☐
Subtotal: Q plus R			896			
Total: 895 plus 896						S
Amount N minus amount S					-32,965	T
Total capital losses: If amount T is a loss, enter it on line 210 of Schedule 4						
Taxable capital gains: If amount T is a gain, enter it on this line and multiply		x 50 % =				U
Enter amount U on line 113 of Schedule 1						

Portion of gain or loss from foreign sources (100%) (excluding business investment losses) ....

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year)	3 Cost of acquisitions during the year (new property must be available for use)*	4 Net adjustments**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)***	7 Reduced undepreciated capital cost	8 CCA rate %	9 Recapture of capital cost allowance (line 107 of Schedule 1)	10 Terminal loss (line 404 of Schedule 1)	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)****	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11)
	200		201	203	205	207	211		212	213	215	217	220
1	1	Dist'n Plant >87	6,538,491			0		6,538,491	4	0	0	261,540	6,276,951
2	2	Dist'n Plant < 88	3,653,780			0		3,653,780	6	0	0	219,227	3,434,553
3	1	Transformers > 87	5,061,497			0		5,061,497	4	0	0	202,460	4,859,037
4	2	Transformers < 88	701,843			0		701,843	6	0	0	42,111	659,732
5	1	Meters > 87	305,318			0		305,318	4	0	0	12,213	293,105
6	2	Meters < 88	119,263			0		119,263	6	0	0	7,156	112,107
7	1	Buildings	650,255	42,450		0	21,225	671,480	4	0	0	26,859	665,846
8	2	Dist'n Stations	331,183			0		331,183	6	0	0	19,871	311,312
9	8	Office equipment	34,445	5,984		0	2,992	37,437	20	0	0	7,487	32,942
10	8	Stores/Comm/Supe etc	118,176	36,006		0	18,003	136,179	20	0	0	27,236	126,946
11	10	Computer Hardware	23,591			0		23,591	30	0	0	7,077	16,514
12	12	Computer Software	47,158	66,892		0	33,446	80,604	100	0	0	80,604	33,446
13	10	Motor Vehicles	125,255	250,400		26,000	112,200	237,455	30	0	0	71,237	278,418
14	8	Inventory spare part	85,258			0		85,258	20	0	0	17,052	68,206
15	17	Telephone System	22,314			0		22,314	8	0	0	1,785	20,529
16	8	Lighting	1,867			0		1,867	20	0	0	373	1,494
17	17	Paving	19,374			0		19,374	8	0	0	1,550	17,824
18	6	Fencing	6,907			0		6,907	10	0	0	691	6,216
19	8	PCB Storage	3,112			0		3,112	20	0	0	622	2,490
20	1	SCADA system	247,053	12,721		0	6,361	253,413	4	0	0	10,137	249,637
21	2	Invent Dist'n Meter	49,873			0		49,873	6	0	0	2,992	46,881
22	45	Computer hardware - new	20,339			0		20,339	45	0	0	9,153	11,186
23	47	Distribution assets after Feb 22,	4,001,373	931,235		0	465,618	4,466,990	8	0	0	357,359	4,575,249

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
24	50	Computer Hardware		21,275		0	10,638	10,637	55	0	0	5,850	15,425
		Total	22,167,725	1,366,963		26,000	670,483	22,838,205				1,392,642	22,116,046

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		1,366,963		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
	+			
Total additions per books	=	1,366,963	►	1,366,963
Proceeds up to original cost – Schedule 8 regular classes		26,000		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
	+			
Total proceeds per books	=	26,000	►	26,000
Depreciation and amortization per accounts – Schedule 1			–	1,306,540
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	24,515
Net change per tax return			=	58,938

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		18,940,760
Opening net book value	–	18,889,302
Net change per financial statements	=	51,458

If the amounts from the tax return and the financial statements differ, explain why below.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Niagara-on-the-Lake Energy Inc.		86376 1490 RC0001	1	1,001	100.000			6,901,334
2.	Energy Services Niagara Inc.		86360 6125 RC0001	3					
3.	Town of Niagara-on-the-Lake		NR	4					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide.*
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200	16,327 A
Add: Cost of eligible capital property acquired during the taxation year	222			
Other adjustments	226			
Subtotal (line 222 plus line 226)		x 3 / 4 =	B	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 =	C	
amount B minus amount C (if negative, enter "0")			▶	D
Amount transferred on amalgamation or wind-up of subsidiary			224	E
Subtotal (add amounts A, D, and E)			230	16,327 F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242	G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244	H		
Other adjustments	246	I		
(add amounts G,H, and I)		x 3 / 4 =	248	J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)				16,327 K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		249		
amount K	16,327			
less amount from line 249				
Current year deduction	16,327 x 7.00 % =	250	1,143 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			1,143 ▶	1,143 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	15,184 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")		►		5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409	►		9	
Line 6 minus line 9 (if negative, enter "0")				►	O
Line N minus line O (if negative, enter "0")					P
Line 5			x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")					R
Amount R			x 2 / 3 =		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)				410	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day [ ]

Enter the calendar year to which the agreement applies . . . . **050** Year 2007

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	1	400,000	100.0000	400,000	
2	Niagara-on-the-Lake Energy Inc.	86376 1490 RC0001	1	400,000			
3	Energy Services Niagara Inc.	86360 6125 RC0001	1	400,000			
				Total	100.0000	400,000	A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from preceding tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax regulations.* References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a ten-year carryforward for credits earned in tax years that end before 2006 and a twenty-year carryforward for credits earned in tax years that end after 2005.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - qualified expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Claim for Scientific Research and Experimental Development (SR&ED) Carried out in Canada*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures;* Information Circular 86-4, *Scientific Research and Experimental Development;* Pamphlet T4052, *An Introduction to the Scientific Research and Experimental Development Program;* and Guide T4088, *Claiming Scientific Research and Experimental Development* (guide to Form T661).

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government assistance or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Qualified expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. For more information, see Interpretation Bulletin IT-151. Special rules apply to specified and limited partners.
6. For SR&ED expenditures made after February 22, 2005, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone. For SR&ED expenditures made prior to February 23, 2005, the expression "in Canada" generally includes the 12 nautical mile territorial sea.

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) throughout the tax year, this percentage may apply to you on the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC throughout the current tax year that incurred qualified expenditures for SR&ED in any area in Canada after 1995	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures:	
• in 2003	5 %
• in 2004	7 %
• after 2004	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment after May 1, 2006	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC throughout the current tax year and the taxable income (before any loss carrybacks) for its preceding year cannot be more than its business limit for that preceding year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the preceding calendar year, cannot be more than the total of their business limits for that last year.

Note: A CCPC calculating a refundable ITC for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). For tax years ending after March 22, 2004, the association rule remains the same except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are not qualifying corporations may also earn a 100% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . **102** 1 Yes [ ] 2 No [X]

If *Yes*, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in.
For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.*

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province) 120	Amount of investment 125

*CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the preceding tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired* 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 ______ x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the preceding year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

* The credit expires after 10 tax years if it was earned in a tax year ending before 2006 and after 20 tax years if it was earned in a tax year ending after 2005.

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st preceding tax year				Credit to be applied	901
2nd preceding tax year				Credit to be applied	902
3rd preceding tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

SR&ED

Part 8 – Qualified expenditures for SR&ED

Current expenditures	350	
Capital expenditures	360	
Repayments made in the year (from line 560 on Form T661)	370	
Total (this must equal the amount from line 570 on Form T661)	380	

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation was a CCPC throughout the current tax year.

Note: A CCPC that calculates SR&ED expenditure limit for tax years ending before March 23, 2004, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1). This also applies for tax years ending after March 22, 2004, except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . 385 1 Yes ☐ 2 No ☒

Complete lines 390 and 395 if you answered *No* to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

a) Enter your taxable income for the preceding tax year* 390 1,312,659

b) Enter your reduced business limit** for the current tax year* (this amount cannot be more than the amount at line 4 on page 4 of the T2 return) 395

* If either of the tax years referred to at line 390 or 395 is less than 51 weeks, multiply the taxable income or the business limit by the following result: 365 divided by the number of days in these tax years. For details on the expression "Reduced business limit," see line 652 of the *T2 Corporation – Income Tax Guide*.

** If the corporation is claiming only a portion of the business limit from line 4 on page 4 of the T2 return because of its association with other corporations, calculate your reduced business limit as if the corporation was not associated in the current tax year. Enter the result at line 395.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC throughout the current tax year

For stand-alone corporations: $ **5,000,000** *

Subtract: line 390 from Part 9 or $400,000*, whichever is more . . . . . 1,312,659 x 10 = 13,126,590

Excess (if negative, enter "0") . . . . . F

Line F ______ x Line 395 / Line 4 on page 4 of the T2 return 400,000 = ... **G

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . . 400 **H

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ______ x Number of days in the tax year 365 / 365 = ... I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) 410

* If your tax year immediately follows a tax year that ended before 2007, the references to $6,000,000 and $400,000 should be $5,000,000 and $300,000 respectively.

** Amount G or H cannot be more than $2,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 % =		K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =		N

Repayments (amount from line 370 in Part 8) ....

If a corporation makes a repayment of any government assistance, non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount.

460		x	35 % =	
470		x	30 % =	
480		x	20 % =	
			Total	▶ O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) ....

* For corporations that are not CCPCs throughout the year, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the preceding tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	510		
Credit expired*	515		
	Subtotal		▶
ITC at the beginning of the tax year			520
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	530		
Total current-year credit	540		
Credit allocated from a partnership	550		
	Subtotal		▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B2 in Part 30)	560		
Credit carried back to the preceding year(s) (from Part 13)			P
Credit transferred to offset Part VII tax liability	580		
	Subtotal		▶
Credit balance before refund			Q
Deduct:			
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610
ITC closing balance on SR&ED			620

* The credit expires after 10 tax years if it was earned in a tax year ending before 2006 and after 20 tax years if it was earned in a tax year ending after 2005.

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st preceding tax year				Credit to be applied	911	
2nd preceding tax year				Credit to be applied	912	
3rd preceding tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

Credit balance before refund (amount Q from Part 12) . . . . . ________ R

Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11) ________ S

Refundable credits (amount R or S, whichever is less)* . . . . . ________ T

Amount J from Part 11 . . . . . ________ U

Subtract: Amount T or U, whichever is less . . . . . ________ V

Net amount (if negative, enter "0") . . . . . ________ W

Amount W ________ x 40 % . . . . . ________ X

Add: Amount V . . . . . ________ Y

Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12) . . . . . ________ Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount should be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12) . . . . . ________ AA

Amount J from Part 11 . . . . . ________ BB

Subtract: Amount AA or BB, whichever is less . . . . . ________ CC

Net amount (if negative, enter "0") . . . . . ________ DD

Amount M from Part 11 . . . . . ________ EE

Amount DD or EE, whichever is less ________ x 40 % . . . . . ________ FF

Add : Amount CC above . . . . . ________ GG

Refund of ITC (amounts FF **plus** GG) . . . . . ________ HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 10 preceding tax years, if the credit was earned in a tax year ending before 2006, or in any of the 20 preceding tax years, if the credit was earned in a tax year ending after 2005;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you acquired all or a part of the qualified expenditure from another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

A The rate percentage that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B The proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C The amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED (continued)

Calculation 2 (continued) – Only if you acquired all or a part of the qualified expenditure from another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

D The amount determined by the formula **(A x B) - C**	E The ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (enter this amount on line MM in Part 17) ____________ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12 on page 5. However, if the partnership does not have sufficient ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ____________ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16 . . . . ____________ LL

Recaptured ITC for calculation 2 from line JJ in Part 16 above . . . . ____________ MM

Recaptured ITC for calculation 3 from line KK in Part 16 above . . . . ____________ NN

Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN . . . . ____________ OO
(Enter amount OO at line A1 in Part 29.)

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year and after 2002.

List of minerals 800

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there were no mineral title, identify the project and mining division only.

Project name 805	Mineral title 806	Mining division 807

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year and after 2002, for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year and after 2002 for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year and after 2002:

Description 825	Amount 826

Add amounts at column 826	▶		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9) and does not include an amount renounced under subsection 66(12.6).

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

Part 19 – Calculation of current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the preceding tax year . . . .

Deduct:

Credit deemed as a remittance of co-op corporations **841**

Credit expired* **845**

Subtotal ▶

ITC at the beginning of the tax year **850**

Add:

Credit transferred on amalgamation or wind-up of subsidiary **860**

Expenditures from line YY, Part 18, incurred in 2003 . . . . **865** x 5 % = ZZ

Expenditures from line YY, Part 18, incurred in 2004 . . . . **867** x 7 % = AAA

Expenditures from line YY, Part 18, incurred after 2004 . . . . **870** x 10 % = BBB

Total current-year credit (add amounts ZZ, AAA, and BBB) . . . . **880** ▶

Total credit available . . . .

Deduct:

Credit deducted from Part I tax (enter on line B3 in Part 30) **885**

Credit carried back to the preceding year(s) (from Part 20) CCC

Subtotal ▶

ITC closing balance from pre-production mining expenditures **890**

* The credit expires after 10 tax years if it was earned in a tax year ending before 2006 and after 20 tax years if it was earned in a tax year ending after 2005.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st preceding tax year				Credit to be applied	921	
2nd preceding tax year				Credit to be applied	922	
3rd preceding tax year				Credit to be applied	923	

Total (enter on line CCC in Part 19)

APPRENTICESHIP JOB CREATION

Part 21 – Calculation of total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) .... 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice. Also enter the name of the eligible trade, the eligible salary and wages* payable for employment after May 1, 2006, and 10% of this amount. Then enter the lesser of 10% of eligible salary and wages or $2,000.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	434A-A82796	Power Line Worker	16,864	1,686	1,686
2.					
				Total current-year credit (enter at line 640)	1,686

* Net of any other government or non-government assistance received or to be received.

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the preceding tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
	Subtotal		▶
ITC at the beginning of the tax year		625	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (total of column 605)	640	1,686	
Credit allocated from a partnership	655		
	Subtotal	1,686 ▶	1,686
Total credit available			1,686
Deduct:			
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	1,686	
Credit carried back to the preceding year(s) (from Part 23)		DDD	
	Subtotal	1,686 ▶	1,686
ITC closing balance from apprenticeship job creation expenditures		690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st preceding tax year				Credit to be applied	931	
2nd preceding tax year				Credit to be applied	932	
3rd preceding tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

CHILD CARE SPACES

Part 24 – Eligible expenditures from the current tax year

Enter the eligible expenditures that the corporation incurred after March 18, 2007, to create licensed child care spaces for the children of the employees and, potentially, for other children. The eligible expenditures include:

a) the cost of depreciable property (other than specified property); and,

b) the amount of specified child care start-up costs;

acquired or incurred solely for the purpose of the creation of the new child care spaces at a licensed child care facility.

a) Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

*CCA: capital cost allowance

Cost of depreciable property (total of column 695) 715 ________ EEE

Add: b) Specified child care start-up costs from the current tax year

Landscaping to create an outdoor play area for the children . . . . 702 ________

Initial fees for licensing, regulatory and building permits . . . . 705 ________

Architectural fees for designing the child care facility . . . . 707 ________

Children's educational material . . . . 709 ________

Total specified child-care start-up costs ________ ► ________ FFF

Total eligible expenditures for child-care spaces (amount EEE plus amount FFF) . . . . ________ GGG

Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG) . . . . 725 ________ HHH

Excess (amount GGG minus amount HHH) (if negative, enter "0") ________ III

Add: Repayments of government and non-government assistance . . . . 735 ________ JJJ

Total eligible expenditures for child-care spaces (amount III plus amount JJJ) . . . . 745 ________

Part 25 – Calculation of total current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred after March 18, 2007, to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			× 25 % =		KKK
Number of child care spaces	755		× $ 10,000 =		LLL
ITC from child care spaces expenditures (lesser of KKK and LLL)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the preceding tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal			▶
ITC at the beginning of the tax year		775	
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal			▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the preceding year(s) (from Part 27)		NNN	
Subtotal			▶
ITC closing balance for child care space creation expenditures		790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st preceding tax year	2006-12-31	Credit to be applied	941	
2nd preceding tax year	2005-12-31	Credit to be applied	942	
3rd preceding tax year	2004-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's ITC balance if, at any time within the five calendar years of the creation of the new child care space:

- the new child care space ceases to be available; or
- property that was an eligible expenditurein respect of the child care space is:
  - sold or leased to another person; or
  - converted to another use.

25% of eligible expenditure that was taken into account in determining the credit . . . . 795 ____

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . 797 ____

Amount from line 795 or line 797, whichever is less . . . . ____ OOO

Calculation 2

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26 on page 13. However, if the partnership does not have sufficient ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC 799 ____ PPP

Total recapture of child care spaces investment tax credit – Add lines OOO and PPP
(Enter amount QQQ at line A2 in Part 29.) . . . . ____ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 on page 8		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 (Enter amount A3 at line 602 on page 7 of the T2 return.)		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	1,686	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4 and B5) (Enter amount B6 at line 652 on page 7 of the T2 return.)	1,686	B6

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
1,686	1,686			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC expired (H) (see note)	ITC end of year (E-F-G-H) (see note)
1st prior year					
2nd prior year					
3rd prior year					
4th prior year					
5th prior year					
6th prior year					
7th prior year					
8th prior year					
9th prior year					
10th prior year					
Total					

B+C+D+G **Total ITC utilized** 1,686

Note: The **ITC end of year** includes the amount of ITC expired from the 10th preceding year that is in column (H). Note that this credit expires only at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 845 or on the line *Credit expired* for the child care space creation, as applicable, of Schedule 31 for the subsequent period.

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder			Percentage common shares	Percentage preferred shares
		Business Number	Social insurance number	Trust number		
	100	200	300	350	400	500
1	Niagara-on-the-Lake Energy Inc.	86376 1490 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
NIAGARA-ON-THE-LAKE HYDRO INC.	86360 5929 RC0001	2007-12-31

On: 2007-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")			050		A
GRIP at the end of the previous tax year			100	1,607,082	B
Taxable income for the year (DICs enter "0")*	110	731,167 C			
Income for the credit union deduction* (amount E in Part 3 of Schedule 17) — 120					
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less* — 130					
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income* — 140					
Subtotal (add lines 120, 130, and 140) ►		D			
Income taxable at the general corporate rate (line C minus line D)	150	731,167			
After-tax income (line 150 multiplied by 68 %)			190	497,194	E
Eligible dividends received in the tax year	200				
Dividends deductible under section 113 received in the tax year	210				
Subtotal (add lines 200 and 210) ►					F
GRIP addition:					
Becoming a CCPC (line PP from Part 4)	220				
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230				
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240				
Subtotal (add lines 220, 230, and 240) ►			290		G
Subtotal (add lines A or B (as applicable), E, F, and G)				2,104,276	H
Eligible dividends paid in the previous tax year	300				
Excessive eligible dividend designations made in the previous tax year	310				
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.					
Subtotal (line 300 minus line 310) ►					I
GRIP before adjustment for specified future tax consequences (line H minus line I) (amount can be negative)			490	2,104,276	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)			560		
GRIP at the end of the year (line 490 minus line 560) Enter this amount on line 160 on Schedule 55.			590	2,104,276	

* **Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year		1,312,659 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	300,000 L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (add lines K1, L1, and M1)	300,000 ►	300,000 O1	
Subtotal (line J1 minus line O1) (if negative, enter "0")		1,012,659 ►	1,012,659 P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ S1

Aggregate investment income (line 440 of the T2 return) . . . . ______ T1

Subtotal (**add** lines R1,S1, and T1) ______ ▶ ______ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ______ ▶ ______ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") ______ X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 multiplied by 68 %) . . . **500** ______

Second previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year 504,575 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by** 100/7 . . . . . ______ N2

Subtotal (**add** lines K2, L2, M2, and N2) ______ ▶ ______ O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") 504,575 ▶ 504,575 P2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ______ Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ S2

Aggregate investment income (line 440 of the T2 return) . . . . ______ T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by** 100/7 . . . . . ______ U2

Subtotal (**add** lines R2, S2, T2, and U2) ______ ▶ ______ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ______ ▶ ______ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") ______ X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 multiplied by 68 %) **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2004-12-31

Taxable income before specified future tax consequences from the current tax year . . . . _______ J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _______ L3

Aggregate investment income (line 440 of the T2 return) . . . . _______ M3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . _______ N3

Subtotal (**add** lines K3, L3, M3, and N3) _______ ▶ _______ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") _______ ▶ _______ P3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . _______ Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _______ R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _______ S3

Aggregate investment income (line 440 of the T2 return) . . . . _______ T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . _______ U3

Subtotal (**add** lines R3, S3, T3, and U3) _______ ▶ _______ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") _______ ▶ _______ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") _______ X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . **540** _______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . _______ Y

Enter amount Y on line 560.

***Note:** The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . _______ AA

Eligible dividends paid by the corporation in its last tax year . . . . _______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . _______ CC

Subtotal (line BB **minus** line CC) _______ ▶ _______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)
(line AA **minus** line DD) . . . . _______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

– line 230 for post-amalgamation; or
– line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ______ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ______

Net capital losses . . . . ______

Farm losses . . . . ______

Restricted farm losses . . . . ______

Limited partnership losses . . . . ______

Subtotal ______ ► ______ HH

Subtotal (**add** lines FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ______ JJ

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ______ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ______ ► ______ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Ontario

Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return.** Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)*
NIAGARA-ON-THE-LAKE HYDRO INC.

Ontario Corporations Tax Account No. (MOF): 1800140

Mailing Address
P.O. Box 460
8 Henegan Road
Virgil
ON CA L0S 1T0

This Return covers the Taxation Year
Start (year month day): 2007-01-01
End (year month day): 2007-12-31

Has the mailing address changed since last filed CT23 Return? [ ] Yes — Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 2000-07-01

Registered/Head Office Address
P.O. Box 460
8 Henegan Road
Virgil
ON CA L0S 1T0

Ontario Corporation No. (MGS): 1424833

Location of Books and Records
P.O. BOX 460,
8 HENEGAN ROAD
Virgil
ON CA L0S 1T0

Canada Revenue Agency Business No.
If applicable, enter: 86360 5929 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
PHILIP WORMWELL	(905) 468-4235	

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day):
Ceased (year month day):
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s):

Ministry Use

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ▶ [X] No Change

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
PHILIP WORMWELL

PLEASE KEEP FOR REFERENCE

Title: D [ ] Director O [X] Officer P [ ] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired: year ___ month ___ day ___

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
[ ]	[X]	Was the corporation inactive throughout the taxation year?
[X]	[ ]	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
[ ]	[X]	the Carry-back of a Loss?
[ ]	[X]	an Overpayment?
[ ]	[X]	a Specified Refundable Tax Credit?
[ ]	[X]	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	731,167
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses From 715	–	From 704	
Net capital losses (page 16) ______ x inclusion rate 50.000000% =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	731,167
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	731,167

Taxable Income

Number of Days in Taxation Year

From 10 (or 20 if applicable) 731,167 x 30 100.0000% Ontario Allocation x 12.5% x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days: 73 365) = + 29 ______

From 10 (or 20 if applicable) 731,167 x 30 100.0000% Ontario Allocation x 14% x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 32 102,363

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 102,363

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) [X] Yes [ ] No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))				50	731,167
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51	731,167		
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	–	53			
	=		731,167	54	731,167
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55	400,000		

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ______ ÷ ** 365) = + 46 ______

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ ** 365) = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) 48 100.0000% = 45 400,000

Income eligible for the IDSBC From 30 100.0000% ***Ontario Allocation x 56 400,000 (Least of 50, 54 or 45) = 60 400,000

* *Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** *Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** *Note: Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate - - - 7 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ____ ÷ Total Days: 73 365) = + 89 ____ .

8.5 % x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 90 8.5000

IDSBC Rate for Taxation Year 89 + 90 - - - = 78 8.5000

Claim - - - From 60 400,000 x From 78 8.5000 % - - - = 70 34,000

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** - - - From 10 (or 20 if applicable) + 80 731,167

If you are a member of an associated group (X) 81 X (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
Niagara-on-the-Lake Energy Inc.	1800139	2007-12-31	+ 82	
Energy Services Niagara Inc.	1800074	2007-12-31	+ 83	
			+ 84	
Aggregate Taxable Income 80 + 82 + 83 + 84, etc.			= 85	731,167

Number of Days in Taxation Year

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ____ ÷ Total Days: 73 365) = + 115 ____ .

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 116 400,000

115 + 116 = 400,000 ▶ - - - – 114 400,000

(If negative, enter nil) - - - = 86 331,167

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax - - - 4.6670 % x (Days after Dec. 31, 2002: 38 365 ÷ Total Days: 73 365) = + 97 4.6670

From 86 331,167 x From 97 4.6670 % - - - = 87 15,456

From 87 15,456 x From 60 400,000 ÷ From 114 400,000 = 88 15,456

Surtax Lesser of 70 or 88 - - - = 100 15,456

**** Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

Additional Deduction for Credit Unions	110	

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits	+	120	
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	− From	56	400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100: 15,456 ÷ From 30: 100.0000 % ÷ From 78: 8.5000 % = 121: 181,835

*Ontario Allocation

Lesser of 56 or 121	+	122	181,835
120 − 56 + 122	=	130	
Taxable Income	+ From	10	731,167
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	− From	56	400,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	+ From	122	181,835
Subtract: Taxable Income 10: 731,167 X Allocation % to jurisdictions outside Canada	−	140	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses	−	141	
10 − 56 + 122 − 140 − 141	=	142	513,002

Claim

Number of Days in Taxation Year

143 (Lesser of 130 or 142)		Ontario Allocation	Rate	Days		Total Days		
143	X From 30	100.0000 %	X 1.5 %	X 33 (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷ 73	365	= + 154	
143	X From 30	100.0000 %	X 2 %	X 34 (Days after Dec. 31, 2003): 365	÷ 73	365	= + 156	

M&P claim for taxation year 154 + 156	=	160	

***Note:** Ontario Allocation for M&P Credit purposes may differ from 30 if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity = 162

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* — 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 ________ Credit Claimed 180

Subtotal of Income Tax

40 − 70 + 100 − 110 − 160 − 161 − 162 − 170 − 180 = 190: 83,819

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit From [5620] OITC Claim Form *(Attach original Claim Form)* + [191] .

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit From [5798] CT23 Schedule 113 *(Attach Schedule 113)* + [192] 1,852 .

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production [204]
Eligible Credit From [5850] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [193] .

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From [6596]
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. [194]
Eligible Credit From [6598] CT23 Schedule 115 (*Attach Schedule 115*) + [195] .

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit From [6900] OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + [196] .

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit From [6700] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [197] .

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit From [7100] OBRITC Claim Form *(Attach original Claim Form)* + [198] .

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit From [7300] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [199] .

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit From [7400] of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC)
(Attach the original Certificate of Eligibility) + [200] .

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit From [7500] OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + [201] .

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From [5896]
Applies to employment of eligible apprentices. [202] 1
Eligible Credit From [5898] CT23 Schedule 114 (*Attach Schedule 114*) + [203] 2,260 .

Other (specify) + [203.1] .

Total Specified Tax Credits [191] + [192] + [193] + [195] + [196] + [197] + [198] + [199] + [200] + [201] + [203] + [203.1] = [220] 4,112 .

Specified Tax Credits ***Applied to reduce Income Tax*** = [225] 4,112 .

Income Tax [190] – [225] **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = [230] 79,707 .

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in [230] to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation	+ 240	24,756,810
Total Revenue of the corporation	+ 241	17,977,640

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 [X] (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
Niagara-on-the-Lake Energy Inc.	1800139	2007-12-31	+ 243 7,091,736	+ 244 22,737
Energy Services Niagara Inc.	1800074	2007-12-31	+ 245 1,646,770	+ 246 369,128
			+ 247	+ 248
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249 33,495,316	
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.				= 250 18,369,505

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 1,117,664 (If negative, enter zero) X From 30 100.0000 % (Ontario Allocation) X 4 % = 276 44,707

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	− 277	
Subtract: Income Tax	− From 190	83,819
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-39,112

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits)			+ From 190	83,819
Gross CMT Payable	+ From 276	44,707		
Subtract: Foreign Tax Credit for CMT purposes	− From 277			
If 276 − 277 is negative, enter NIL in 290	=	44,707	− 290	44,707
Income Tax eligible for CMT Credit			= 300	39,112
B. Income Tax (after deduction of specified credits)			+ From 230	79,707
Subtract: CMT credit used to reduce income taxes			− 310	
Income Tax			= 320	79,707

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230, 300 ***and your CMT credit carryover available*** 2333.

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333.

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	2,632,307
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	2,234,536
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	4,269,026
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	7,119,389
Bank loans (Int.B. 3013R)	+	354	4,364,295
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	1,509,877
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	22,129,430
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	1,033,136
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	21,096,294
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	-
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	21,096,294

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	8,208
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	955,941
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	964,149

continued on Page 10

Total Assets (Int.B. 3015R) *DOLLARS ONLY*

Total Assets per balance sheet	+	420	24,756,810
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	24,756,810
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371, 372 and 381	–	441	1,033,136
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	23,723,674

Investment Allowance (410 ÷ 450) x 390 — Not to exceed 410	=	460	857,370
Taxable Capital 390 – 460	=	470	20,238,924

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	17,977,640
Total Assets (as adjusted)	From 430	24,756,810

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

Amount		Days		Total Days			Result
7,500,000	x	Days after Dec. 31, 2004 and before Jan. 1, 2006: 36	÷	73: 365	=	+ 501	
10,000,000	x	Days after Dec. 31, 2005 and before Jan. 1, 2007: 37	÷	73: 365	=	+ 502	
12,500,000	x	Days after Dec. 31, 2006 and before Jan. 1, 2008: 38 365	÷	73: 365	=	+ 504	12,500,000
15,000,000	x	Days after Dec. 31, 2007: 39	÷	73: 365	=	+ 505	

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

Rate		Days		Total Days			Result
0.3 %	x	Days before Jan. 1, 2007: 556	÷	73: 365	=	+ 511	%
0.285 %	x	Days after Dec. 31, 2006 and before Jan. 1, 2009: 557 365	÷	73: 365	=	+ 512	0.2850 %

Capital Tax Rate 511 + 512 = 516 0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If [430] and [480] on page 10 are both $3,000,000 or less, enter NIL in [550] on page 12 and complete the return from that point.

C2. If Taxable Capital in [470] **is equal to or less than the TCD** in [503], enter NIL in [550] on page 12 and complete the return from that point.

C3. If Taxable Capital in [470] **exceeds the TCD** in [503], complete the following calculation and transfer the amount from [523] to [543] on page 12, and complete the return from that point.

+ From [470] ____________
− From [503] ____________
= [471] ____________ x From [30] 100.0000 % (Ontario Allocation) x From [516] 0.2850 % (Capital Tax Rate) x Days in taxation year [555] 365 / 365 (366 if leap year) = + [523] ____________

If floating taxation year, refer to Guide.

Transfer to [543] on page 12 and complete the return from that point

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either [509] or [524] and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ [509] (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital [470] on page 10 is equal to or less than the TCD [503] on page 10, enter NIL in [550] on page 12 and complete the return from that point.

If Taxable Capital [470] on page 10 exceeds the TCD [503] on page 10, proceed to **Section E**, enter the TCD amount in [542] in Section E, and complete Section E and the return from that point.

D2. ☒ [524] (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation
Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From [470] on page 10 - - - - + From [470] 20,238,924 •

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
Niagara-on-the-Lake Energy Inc.	1800139	2007-12-31	+ [531]	45,832 •
Energy Services Niagara Inc.	1800074	2007-12-31	+ [532]	854,675 •
			+ [533]	•
Aggregate Taxable Capital [470] + [531] + [532] + [533], etc.			= [540]	21,139,431 •

If [540] above is equal to or less than the TCD [503] on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in [523] in section E below, as applicable.

If [540] above is greater than the TCD [503] on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From [470] 20,238,924 • ÷ From [540] 21,139,431 • X From [503] 12,500,000 • = [541] 11,967,519 •

Transfer to [542] *in Section E below*

Ss.69(2.1) Election Filed

[ ] [591] (X if applicable) **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation is a member of an associated group and/or partnership whose total **aggregate** Taxable Capital [540] above, exceeds the TCD [503] on page 10.

Complete the following calculation and transfer the amount from [523] to [543], and complete the return from that point.

+ From [470] 20,238,924 •
− [542] 11,967,519 •
= [471] 8,271,405 • X From [30] 100.0000 % Ontario Allocation X From [516] 0.2850 % Capital Tax Rate X Days in taxation year [555] 365 / * 365 (366 if leap year) = + [523] 23,574 •

Total Capital Tax for the taxation year

Transfer to [543] *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From [470] • X From [30] 100.0000 % Ontario Allocation X From [516] 0.2850 % Capital Tax Rate - - - - = + [561] •

− Capital tax deduction from [995] relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - − From [995] •

= [562] •

Total Capital Tax for the taxation year

Capital Tax - - - - [562] • X Days in taxation year [555] 365 / * 365 (366 if leap year) - - - - = [563] •

Transfer to [543] *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - - - - = [543] 23,574 •

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - - − [546] •

Capital Tax [543] − [546] *(amount cannot be negative)* - - - - = [550] 23,574 •

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in [550] on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes [565] and [570]. Do not submit with this tax return.)

[565] ______ . (Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1) x [567] ______ % (Capital Tax Rate (1) *(Refer to Guide)*) x From [30] 100.0000 % (Ontario Allocation) x Days in taxation year [555] 365 / * 365 (366 if leap year) = + [569] ______ .

[570] ______ . (Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount) x [571] ______ % (Capital Tax Rate (2) *(Refer to Guide)*) x From [30] 100.0000 % (Ontario Allocation) x Days in taxation year [555] 365 / * 365 (366 if leap year) = + [574] ______ .

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) [569] + [574] = [575] ______ .

* *If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – [585] ______ .

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions [575] – [585] = [586] ______ .

Transfer to [543] *on Page 12*

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements [587] ______ . x 2 % = [588] ______ .
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in [588] and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in [588].)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – [589] ______ .

Premium Tax [588] – [589] = [590] ______ .

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± [600] 731,167 *Transfer to Page 15*

Add:

Federal capital cost allowance	+ 601	1,392,642
Federal cumulative eligible capital deduction	+ 602	1,143
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	
Federal allowable reserves. Balance end of year	+ 605	
Ontario non-allowable reserves. Balance end of year	+ 606	
Ontario allowable reserves. Balance beginning of year	+ 607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	
Federal resource allowance *(Refer to Guide)*	+ 609	
Federal depletion allowance	+ 610	
Federal foreign exploration and development expenses	+ 611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents ▼

Number of Days in Taxation Year

[612] ______ × 5 / 12.5 × (Days after Dec. 31, 2002 and before Jan. 1, 2004 [33] ______ ÷ Total Days [73] 365) = + [633] ______

[612] ______ × 5 / 14 × (Days after Dec. 31, 2003 [34] 365 ÷ Total Days [73] 365) = + [634] ______

Total add-back amount for Management fees, etc. [633] + [634] = ______ ▶ + [613] ______

Federal Scientific Research Expenses claimed in year from line [460] of fed. form T661 excluding any negative amount in [473] from Ont. CT23 Schedule 161 + [615] ______

Add any negative amount in [473] from Ont. CT23 Schedule 161 + [616] ______

Federal allowable business investment loss + [620] ______

Total of other items not allowed by Ontario but allowed federally *(Attach schedule)* + [614] ______

Total of Additions [601] to [611] + [617] + [613] + [615] + [616] + [620] + [614] = 1,393,785 ▶ [640] 1,393,785 *Transfer to Page 15*

Deduct:

Ontario capital cost allowance (excludes amounts deducted under [675])	+ 650	1,392,642
Ontario cumulative eligible capital deduction	+ 651	1,143
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	
Federal allowable reserves. Balance beginning of year	+ 656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	
Ontario depletion allowance	+ 658	
Ontario resource allowance *(Refer to Guide)*	+ 659	
Ontario current cost adjustment *(Attach schedule)*	+ 661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	

Subtotal of deductions for this page [650] to [659] + [661] + [675] [681] 1,393,785 *Transfer to Page 15*

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1	From ±	600	731,167
Total of Additions on page 14	From =	640	1,393,785
Sub Total of deductions on page 14	From =	681	1,393,785

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(*Applies* only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662 ______

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 ______ x 100 / From 30 100.0000 Ontario Allocation] − From 662 ______ = 663 ______

Workplace Child Care Tax Incentive (WCCT)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 ______ x 30 % x 100 / From 30 100.0000 Ontario allocation] = 666 ______

Workplace Accessibility Tax Incentive (WATI)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 ______ x 100 % x 100 / From 30 100.0000 Ontario allocation] = 668 ______

Number of Employees accommodated 669 ______

Ontario School Bus Safety Tax Incentive (OSBSTI)
(*Applies* to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 ______ x 30 % x 100 / From 30 100.0000 Ontario allocation] = 671 ______

Educational Technology Tax Incentive (ETTI)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 ______ x 15 % x 100 / From 30 100.0000 Ontario allocation] = 673 ______

Ontario allowable business investment loss	+	678	
Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161	+	679	
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	+	677	
Total of other deductions allowed by Ontario *(Attach schedule)*	+	664	

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 1,393,785 ▶ 680 1,393,785

Net income (loss) for Ontario Purposes 600 + 640 − 680 = 690 731,167

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2) 23,386	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711 32,965	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713 32,965	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719 56,351	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 1999-09-30	817 (9)	860 (9)		850	870
801 8th preceding taxation year 2000-09-30	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2001-09-30	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2001-12-31	820	830	840	853	873
804 5th preceding taxation year 2002-12-31	821	831	841	854	874
805 4th preceding taxation year 2003-12-31	822	832	842	855	875
806 3rd preceding taxation year 2004-12-31	823	833	843	856	876
807 2nd preceding taxation year 2005-12-31	824	834	844	857	877
808 1st preceding taxation year 2006-12-31	825	835	845	858	878
809 Current taxation year 2007-12-31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation,** enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920 32,965	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2004-12-31	911	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929 32,965	939	949

Summary

Income Tax	+	From 230 or 320	79,707
Corporate Minimum Tax	+	From 280	
Capital Tax	+	From 550	23,574
Premium Tax	+	From 590	
Total Tax Payable	=	950	103,281
Subtract: Payments	−	960	313,282
Capital Gains Refund (s.48)	−	965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	−	985	
Specified Tax Credits *(Refer to Guide)*	−	955	
Other, specify	−		
Balance	=	970	-210,001
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	
Apply to (year month day) 2008-12-31		980	210,001 *(Includes credit interest)*

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*: PHILIP WORMWELL

Title: DIRECTOR OF CORPORATE SERVICES

Full Residence Address:
P.O. Box 460
8 Henegan Road
Virgil, Ontario
ON L0S 1T0

Signature: [signature] | Date: 2008-05-12

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)			± 2100	905,922
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	+ 2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+ 2102			
Equity income from corporations	+ 2103			
Share of partnership(s)/joint venture(s) income	+ 2104			
Dividends received/receivable deductible under fed.s.112	+ 2105			
Dividends received/receivable deductible under fed.s.113	+ 2106			
Dividends received/receivable deductible under fed.s.83(2)	+ 2107			
Dividends received/receivable deductible under fed.s.138(6)	+ 2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) ______ x 3	+ 2109			
Subtotal	=		– 2110	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	+ 2111	211,742		
Provision for deferred income taxes (debits) / cost of future income taxes	+ 2112			
Equity losses from corporations	+ 2113			
Share of partnership(s)/joint venture(s) losses	+ 2114			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+ 2115			
Subtotal	=	211,742	+ 2116	211,742

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

	Add		or Subtract			
** Fed.s.85	+ 2117		or – 2118			
** Fed.s.85.1	+ 2119		or – 2120			
** Fed.s.97	+ 2121		or – 2122			
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or – 2124			
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or – 2126			
** Amounts relating to s.57.10 election/ regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or – 2128			
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			– 2150			
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			– 2155			
Subtotal (Additions)	=				+ 2129	
Subtotal (Subtractions)			=		– 2130	
** Other adjustments					± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131					= 2132	1,117,664
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss					± 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in *Part 2: Continuity of CMT Losses Carried Forward.*)					= 2134	1,117,664
Deduct: * CMT losses: pre-1994 Loss			+ From 2210			
* CMT losses: other eligible losses			+ 2211			
			=		– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	1,117,664

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)		+ 2201	
Add: Current year's losses	+ 2202		
Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203		
Losses from predecessor corporations on wind-up NOTE (3)	+ 2204		
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes			
Subtotal	=	+ 2207	
Adjustments (attach schedule)		± 2208	
CMT losses available 2201 + 2207 ± 2208		= 2209	
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210		
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211		
Losses expired during the year	+ 2212		
Subtotal	=	– 2213	
Balances at End of Year NOTE (5) 2209 – 2213		= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 1999-09-30	2260	2280
2241	8th preceding taxation year 2000-09-30	2261	2281
2242	7th preceding taxation year 2001-09-30	2262	2282
2243	6th preceding taxation year 2001-12-31	2263	2283
2244	5th preceding taxation year 2002-12-31	2264	2284
2245	4th preceding taxation year 2003-12-31	2265	2285
2246	3rd preceding taxation year 2004-12-31	2266	2286
2247	2nd preceding taxation year 2005-12-31	2267	2287
2248	1st preceding taxation year 2006-12-31	2268	2288
2249	Current taxation year 2007-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 *must equal amount in* 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . – From 190

Subtotal (If negative, enter NIL) . . . = ▶ – 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 – 2305 . . . = ▶ + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . + 2325

Amalgamation (X) 2315 ☐ Yes Wind-up (X) 2320 ☐ Yes

Subtotal 2301 + 2310 + 2325 . . . = 2330

Adjustments *(Attach schedule)* . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . + 2334

Subtotal . . . = ▶ – 2335

Balance at End of Year NOTE (4) 2333 – 2335 . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 1999-09-30	2360	2380
2341	8th preceding taxation year 2000-09-30	2361	2381
2342	7th preceding taxation year 2001-09-30	2362	2382
2343	6th preceding taxation year 2001-12-31	2363	2383
2344	5th preceding taxation year 2002-12-31	2364	2384
2345	4th preceding taxation year 2003-12-31	2365	2385
2346	3rd preceding taxation year 2004-12-31	2366	2386
2347	2nd preceding taxation year 2005-12-31	2367	2387
2348	1st preceding taxation year 2006-12-31	2368	2388
2349	Current taxation year 2007-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 *must equal amount in* 2336.

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-09-30					
9th Prior Year	1999-09-30					
8th Prior Year	2000-09-30					
7th Prior Year	2001-09-30					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1998-09-30					
9th Prior Year	1999-09-30					
8th Prior Year	2000-09-30					
7th Prior Year	2001-09-30					
6th Prior Year	2001-12-31					
5th Prior Year	2002-12-31					
4th Prior Year	2003-12-31					
3rd Prior Year	2004-12-31					
2nd Prior Year	2005-12-31					
1st Prior Year	2006-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1998-09-30						
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
Total						

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Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Town of Niagara-on-the-Lake	+ 553,056
Due to Town of NOTL	+ 6,566,333
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
	+
Total *Transfer to* 353 *of the CT23*	= 7,119,389

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Ontario Summary of Dispositions of Capital Property

2005 and later taxation years

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

- **For a corporation that has disposed of capital property or claimed an allowable business investment loss, or both, in the taxation year.**
- **This schedule may be used to make a designation under section 34(10) of the *Corporations Tax Act* provided the corporation has made a designation under paragraph 111(4) (e) of the *Income Tax Act* (Canada), if control of the corporation has been acquired by a person or group of persons.**

Part A: Designation under section 34(10) of the *Corporations Tax Act*

Complete part A if there are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e) of the *Income Tax Act* (Canada) or section 34(10) of the *Corporations Tax Act*.

Property	Class #	Date of disposition YYYY/MM/DD	Proceeds of disposition	Adjusted cost base	Other adjustments	Designated amount	Gain or loss

Part B: Inter-provincial asset transfers

Complete part B if there was any disposition shown on the schedule as a result of a federal election under section 85 of the *Income Tax Act* (Canada) that transferred assets to a non-arm's length corporation with a permanent establishment in another Canadian jurisdiction.

Property	Class #	Corporation name of transferee/or	Date of disposition YYYY/MM/DD	Cost of asset in other jurisd.	Name of other jurisdiction	Allocation ratio to other jurisdictions	Ontario elected amount	Gain or loss
						%		
						%		
						%		
						%		

Part 1 – Shares

	1 Types of capital property			2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)
	No. of shares	Name of corporation	Class of shares						
1									
								Totals	A

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

1 Types of capital property	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain or (loss) (col. 4 less cols. 5 & 6)

Part 2 – Real Estate *(Do not include losses on depreciable property)*

	Municipal address	2	3	4	5	6	7
1							
						Totals	B

Part 3 – Bonds

	Face value	Maturity date YYYY/MM/DD	Name of issuer	2	3	4	5	6	7
1									
								Totals	C

Part 4 – Other properties *(Do not include losses on depreciable property)*

	Description	2	3	4	5	6	7
1	ENERConnect Partnership Interest	1999-01-01		18,468	51,433		-32,965
2							
						Totals	-32,965 D

Part 5 – Personal-use property

	Description of capital property	2	3	4	5	6	7
1							

Note: Losses are not deductible Net gain or (loss) E

Part 6 – Listed personal property

	Description	2	3	4	5	6	7
1							

Deduct: Unapplied listed personal property losses from other years .... –

***Note:** Net listed personal property losses may only be applied against personal property gains.* Net gain or (loss) F

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Part 7 – Property qualifying for and resulting in an allowable business investment loss

	1 Name of small business corporation	Shares – enter 1 Debt – enter 2	2 Date of acquisition YYYY/MM/DD	3 Date of disposition YYYY/MM/DD	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario loss (col. 4 less cols. 5 & 6)
1								
				Totals				
							Net Loss	G

Note: Properties listed in Part 7 should not be included in any other Part of Schedule 6.

Allowable business investment loss .... G x 50 % = G1

Transfer to 678 *of the CT23 or CT8*

Determining capital gains and capital losses

Total of A to F (Do not include F if it is a loss)		-32,965
Add: Amount (if any) of capital gain reserve opening balance from Schedule 13	+	
Capital gain dividend received in the year	+	
Subtotal	=	-32,965
Deduct: Amount (if any) of capital gain reserve closing balance from Schedule 13	–	
Gain or Loss (excluding Allowable Business Investment Losses)	=	-32,965 H

Determining taxable capital gains

Gain or Loss (excluding Allowable Business Investment Losses)				-32,965 H
Deduct:				
Gain on donations (made to charities other than private foundations) of securities listed on a prescribed stock exchange				
realized prior to May 2, 2006		x 50 %	–	
realized after May 1, 2006			–	
Gain on donation of ecologically sensitive land				
realized prior to May 2, 2006		x 50 %	–	
realized after May 1, 2006			–	
Gains or Loss				-32,965 I

Include 100% of the losses in box 711 *of the CT23 or CT8*

Taxable capital gains .... -32,965 I x 50 % = J

Transfer to 603 *of the CT23 or CT8*

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Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Is the corporation electing under regulation 1101(5q)? 1 ☐ Yes 2 ☒ No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	6,538,491			0	6,538,491		6,538,491	4	0	0	261,540	6,276,951
2	3,653,780			0	3,653,780		3,653,780	6	0	0	219,227	3,434,553
1	5,061,497			0	5,061,497		5,061,497	4	0	0	202,460	4,859,037
2	701,843			0	701,843		701,843	6	0	0	42,111	659,732
1	305,318			0	305,318		305,318	4	0	0	12,213	293,105
2	119,263			0	119,263		119,263	6	0	0	7,156	112,107
1	650,255	42,450		0	692,705	21,225	671,480	4	0	0	26,859	665,846
2	331,183			0	331,183		331,183	6	0	0	19,871	311,312
8	34,445	5,984		0	40,429	2,992	37,437	20	0	0	7,487	32,942
See schedule	4,771,650	1,318,529		26,000	6,064,179	646,266	5,417,913				593,718	5,470,461
Totals	22,167,725	1,366,963		26,000	23,508,688	670,483	22,838,205				1,392,642	22,116,046

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
8	118,176	36,006		0	154,182	18,003	136,179	20	0	0	27,236	126,946
10	23,591			0	23,591		23,591	30	0	0	7,077	16,514
12	47,158	66,892		0	114,050	33,446	80,604	100	0	0	80,604	33,446
10	125,255	250,400		26,000	349,655	112,200	237,455	30	0	0	71,237	278,418
8	85,258			0	85,258		85,258	20	0	0	17,052	68,206
17	22,314			0	22,314		22,314	8	0	0	1,785	20,529
8	1,867			0	1,867		1,867	20	0	0	373	1,494
17	19,374			0	19,374		19,374	8	0	0	1,550	17,824
6	6,907			0	6,907		6,907	10	0	0	691	6,216
8	3,112			0	3,112		3,112	20	0	0	622	2,490
1	247,053	12,721		0	259,774	6,361	253,413	4	0	0	10,137	249,637
2	49,873			0	49,873		49,873	6	0	0	2,992	46,881
45	20,339			0	20,339		20,339	45	0	0	9,153	11,186
47	4,001,373	931,235		0	4,932,608	465,618	4,466,990	8	0	0	357,359	4,575,249
50		21,275		0	21,275	10,638	10,637	55	0	0	5,850	15,425
Totals	4,771,650	1,318,529		26,000	6,064,179	646,266	5,417,913				593,718	5,470,461

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Ontario Cumulative Eligible Capital Deduction

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 – Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital – balance at end of preceding taxation year *(if negative, enter zero)*			= + 16,327	A
Add: Cost of eligible capital property acquired during the taxation year	+ ____ B			
Other adjustments	+ ____ C			
B + C	= ____	x 3 / 4 = ____ D		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	____	x 1 / 2 = – ____ E		
D minus E *(if negative, enter zero)*		= ____	+ ____	F
Amount transferred on amalgamation or wind-up of subsidiary			+ ____	G
Subtotal A + F + G			= 16,327	H
Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+ ____ I			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+ ____ J			
Other adjustments	+ ____ K			
I + J + K	= ____	x 3 / 4	= – ____	L
Ontario cumulative eligible capital balance H minus L			= 16,327	M

If M is negative, enter zero at line Q and proceed to Part 2, page 2.

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		____ N		
From **M**	16,327			
From **N**	– ____			
Current year deduction M minus N	= 16,327	x 7 % = + 1,143		O
N + O		= 1,143	– 1,143	P

Note: *The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.*

Enter amount in box 651 *of the CT23*

Ontario cumulative eligible capital - closing balance M minus P *(if negative, enter zero)*	= 15,184	Q

See page 2 - Part 2

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
NIAGARA-ON-THE-LAKE HYDRO INC.	1800140	2007-12-31

Part 2 – Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative.

Amount from line M above. *Show this as a positive amount; not negative.*					_____	R
Total cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988			+ _____	1		
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80(7) of the ITA			+ _____	2		
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+ _____	3				
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	– _____	4				
Deduct line 4 from line 3 *(if negative, enter zero)*	= _____	▷	+ _____	5		
Total lines 1 + 2 + 5			= _____	6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 1	_____	7				
Amounts at **Line Z** from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 *(This will be **Line T** in earlier versions of this schedule.)*	+ _____	8				
Total lines 7 + 8	= _____	▷	– _____	9		
Deduct line 9 from line 6 *(if negative, enter zero)*			= _____	▷	– _____	S
R minus S *(if negative, enter zero)*					= _____	T
From Line 5 _____ x 1 / 2					= – _____	U
T minus U *(if negative, enter zero)*					= _____	V
From V _____ x 2 / 3					= _____	W
Lesser of **R** and **S**					= + _____	Z
Amount to be included in income W + Z					= _____	

INDEX FOR EXHIBIT 2

RATE BASE:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement used in this Application follows the definition used in the 2006 EDR Handbook as an average of the balances at the beginning and the end of the 2009 Test Year, plus a working capital allowance, which is 15% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

NOTL Hydro has provided its rate base calculations for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year in Table 1 below.

NOTL Hydro has calculated its 2009 rate base as $21,740,616.

Niagara-on-the-Lake Hydro Inc.

Table 1
Summary of Rate Base

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	29,804,120	34,187,333	35,241,416	36,559,736	38,437,232
Accumulated Depreciation	12,124,061	15,004,356	16,005,729	17,282,748	18,614,426
Net Book Value	17,680,059	19,182,977	19,235,687	19,276,988	19,822,807
Average Net Book Value	17,754,689	19,058,868	19,209,332	19,256,338	19,549,897
Working Capital	13,403,847	14,168,512	14,834,118	15,791,872	14,604,787
Working Capital Allowance	2,010,577	2,125,277	2,225,118	2,368,781	2,190,718
Rate Base	19,765,266	21,184,145	21,434,450	21,625,118	21,740,616

NOTL Hydro has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year in Table 2, below. Details of NOTL Hydro's calculation of its working capital allowance are provided at **Exhibit 2, Tab 4, Schedule 1**.

Table 2
Summary of Working Capital

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Cost of Power	11,890,451	12,591,231	13,081,768	14,003,582	12,706,676
Operations	323,382	260,994	342,844	377,390	373,710
Maintenance	304,410	388,961	431,315	474,671	521,359
Billing & Collecting	244,549	310,202	355,606	312,374	318,798
Community Relations	713	29,210	8,783	1,000	1,020
Administration & General Expense	610,958	557,082	579,955	589,054	649,774
Property Taxes	29,384	30,833	33,846	33,800	33,450
Working Capital	13,403,847	14,168,512	14,834,118	15,791,872	14,604,787

RATE BASE VARIANCE ANALYSIS:

The following Table 1 sets out NOTL Hydro's rate base and working capital calculations for 2006 Board Approved and Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year, and the following variances:

- 2006 Actual against 2006 Board Approved;
- 2007 Actual against 2006 Actual
- 2008 Bridge Year against 2007 Actual; and
- 2009 Test Year against 2008 Bridge Year.

Niagara-on-the-Lake Hydro Inc.
Table 1
Rate Base Variances

Description	2006 OEB Approved*	2006 Actual	Variance from 2006 OEB Approved	2007 Actual Year	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual Year	2009 Test Year	Variance from 2008 Bridge Year
Gross Fixed Assets	29,804,120	34,187,333	4,383,214	35,241,416	1,054,083	36,559,736	1,318,320	38,437,232	1,877,496
Accumulated Depreciation	12,124,061	15,004,356	2,880,295	16,005,729	1,001,373	17,282,748	1,277,019	18,614,426	1,331,677
Net Book Value	17,680,059	19,182,977	1,502,918	19,235,687	52,710	19,276,988	41,301	19,822,807	545,819
Average Net Book Value	17,754,689	19,058,868	1,304,180	19,209,332	150,464	19,256,338	47,006	19,549,897	293,560
Working Capital	13,403,847	14,168,512	764,665	14,834,118	665,606	15,791,872	957,754	14,604,787	(1,187,085)
Working Capital Allowance	2,010,577	2,125,277	114,700	2,225,118	99,841	2,368,781	143,663	2,190,718	(178,063)
Rate Base	19,765,266	21,184,145	1,418,880	21,434,450	250,304	21,625,118	190,669	21,740,616	115,497

Note: The 2006 OEB Approved rate base was determined through the 2006 EDR process and is based on the 2004 year end rate base adjusted for Tier 1 Adjustments. As such, the variance between 2006 Actual and 2006 OEB Approved spans a two year period.

NOTL Hydro has calculated the variance threshold on its rate base in accordance with the Filing Requirements. This calculation is summarized in Table 2 below:

Table 2
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	$29,804,120	34,187,333.31	$35,241,416	$36,559,736	$38,437,232
Accumulated Depreciation	$12,124,061	15,004,356.37	$16,005,729	$17,282,748	$18,614,426
Net Book Value	$17,680,059	19,182,976.94	$19,235,687	$19,276,988	$19,822,807
Variance calc 1% NBV		$191,830	$192,357	$192,770	$198,228

Table 3 below identifies the specific variances from Table 1 which exceed the threshold in absolute value:

Niagara-on-the-Lake Hydro Inc.
Table 3
Material Rate Base Variances

Description	2006 OEB Approved*	2006 Actual	Material Variance from 2006 OEB Approved	2007 Actual Year	Material Variance from 2006 Actual	2008 Bridge Year	Material Variance from 2007 Actual Year	2009 Test Year	Material Variance from 2008 Bridge Year
Gross Fixed Assets	29,804,120	34,187,333	4,383,214	35,241,416	1,054,083	36,559,736	1,318,320	38,437,232	1,877,496
Accumulated Depreciation	12,124,061	15,004,356	2,880,295	16,005,729	1,001,373	17,282,748	1,277,019	18,614,426	1,331,677
Net Book Value	17,680,059	19,182,977	1,502,918	19,235,687	0	19,276,988	0	19,822,807	545,819
Average Net Book Value	17,754,689	19,058,868	1,304,180	19,209,332	0	19,256,338	0	19,549,897	293,560
Working Capital	13,403,847	14,168,512	764,665	14,834,118	665,606	15,791,872	957,754	14,604,787	(1,187,085)
Working Capital Allowance	2,010,577	2,125,277	0	2,225,118	0	2,368,781	0	2,190,718	0
Rate Base	19,765,266	21,184,145	1,418,880	21,434,450	250,304	21,625,118	0	21,740,616	0

NOTL Hydro offers the following comments in respect of the relevant variances exceeding the threshold as identified above:

2009 Test Year:

As shown in Table 1 above, the total rate base in the 2009 test year is forecast to be $21,740,616 . Average net fixed assets accounts for $19,549,897 of this total. The allowance for working capital totals $2,190,718

The total rate base is expected to be $115,497 higher in the 2009 Test Year than in the 2008 Bridge Year. This increase is shown in Table 1 above. While the increase falls below the materiality threshold, it is the net effect of a material increase in average net fixed assets of $293,560 and a material decrease in working capital allowance of -$178,063 . The increase in fixed assets is discussed in detail in **Exhibit 2, Tab 2, Schedule 3**.

A detailed calculation of the working capital allowance for the 2009 Test Year can be found at **Exhibit 2, Tab 4, Schedule 1**.

A major component of the change from the 2008 Bridge Year is the -$1,296,906 decrease in the projected cost of power as reported in the Navigant Consulting report dated April 11, 2008 commissioned by the OEB. NOTL Hydro has assumed a cost of power of $0.0672 per kWh in 2008 and $0.05373 per kWh in 2009 based on this current Navigant report. If an update of the projected cost of power is provided by the OEB at a later date, it is assumed that the working capital allowance will be adjusted accordingly.

2008 Bridge Year:

The total rate base for the 2008 Bridge Year is expected to be $21,625,118 , which represents an increase of $190,669 over the 2007 Actual year. This change, as well as the changes in average net fixed assets and working capital which it comprises, falls below the materiality threshold.

2007 Actual:

The rate base for 2007 Actual increased over 2006 Actual by $250,304. Although this change exceeds the materiality threshold, the changes in average net fixed assets and working capital which it comprises fall below the materiality threshold.

The increase in fixed assets is discussed in detail in **Exhibit 2, Tab 2, Schedule 3**.

A detailed calculation of the working capital allowance can be found at **Exhibit 2, Tab 4, Schedule 1**.

2006 Actual:

The rate base for 2006 Actual increased over 2006 Board Approved by $1,418,880. This increase is made up of a material increase in average net assets of $1,304,180 and an increase in working capital allowance which falls below the materiality threshold. The variance in average net assets is mainly due to the requirement that only 50% of the Tier 1 adjustment of $2,130,000 for a new transformer station with a 2005 in-service date was included in the rate base in accordance with the 2006 EDR guidelines and rate model. The full amount of $2,130,000 was reflected in the 2006 actual audited data, in accordance with OEB accounting policy.

The increase in fixed assets is discussed in detail in **Exhibit 2, Tab 2, Schedule 3**.

GROSS ASSETS – PROPERTY, PLANT AND EQUIPMENT; ACCUMULATED DEPRECIATION

CONTINUITY STATEMENTS:

Table 1
Niagara-on-the-Lake Hydro Inc. Distribution & Operations
Fixed Asset Continuity Schedule as at December 31, 2006

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2006
(Excludes account 1606 - Intangible plant: cost $25,038, annual depreciation $1,252)

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	259,794	2,200		261,994	-			-	261,994
47	1808	Buildings - Substations	-	-		-	-			-	-
13	1810	Leasehold Improvements	-	-		-	-			-	-
47	1815	Transformer Station Equipment > 50 kV	4,816,646	179,472		4,996,118	195,608	122,660		318,267	4,677,851
47	1820	Substation Equipment	242,132	-		242,132	155,028	5,670		160,698	81,434
47	1825	Storage Battery Equipment	-	-		-	-			-	-
47	1830	Poles, Towers & Fixtures	4,025,232	175,369		4,200,601	2,163,437	130,216		2,293,653	1,906,948
47	1835	OH Conductors & Devices	5,294,877	223,276		5,518,153	2,702,445	173,000		2,875,445	2,642,708
47	1840	UG Conduit	3,154,643	442,070		3,596,713	1,181,965	131,290		1,313,255	2,283,458
47	1845	UG Conductors & Devices	6,455,141	515,439		6,970,580	2,575,840	260,378		2,836,218	4,134,362
47	1850	Line Transformers	5,854,601	776,244	237,699	6,393,146	2,456,417	212,361	19,401	2,649,377	3,743,769
47	1855	Services (OH & UG)	1,386,083	238,118		1,624,200	175,826	60,206		236,032	1,388,168
47	1860	Meters	983,575	53,826	4,440	1,032,961	523,372	35,408	2,664	556,116	476,844
47	1861	Smart Meters	-	-		-				-	-
N/A	1905	Land	49,000	-		49,000	-			-	49,000
CEC	1906	Land Rights	-	-		-				-	-
47	1908	Buildings & Fixtures	858,924	8,420		867,344	256,520	14,885		271,405	595,938
13	1910	Leasehold Improvements	-	-		-				-	-
8	1915	Office Furniture & Equipment	153,761	9,406		163,168	123,359	4,376		127,736	35,432
10	1920	Computer - Hardware up to Mar 22/04	233,047			233,047	212,802	9,843	-	222,645	10,402
45	1921	Computer - Hardware Mar 23/04 to Mar 19/07	24,468	14,470	-	38,938	3,808	6,341	-	10,148	28,790
45.1	1921	Computer - Hardware post Mar19/07				-				-	-
12	1925	Computer - Software	730,451	94,316		824,767	440,460	194,120		634,579	190,188
10	1930	Transportation Equipment	968,658	24,883	25,691	967,850	775,900	52,056	25,691	802,265	165,586
8	1935	Stores Equipment	14,235	-		14,235	13,884	171		14,055	180
8	1940	Tools, Shop & Garage Equipment	369,164	6,580		375,744	211,517	25,072		236,589	139,155
8	1945	Measurement & Testing Equipment	-	-		-				-	-
8	1950	Power operated Equipment	-	-		-				-	-
8	1955	Communications Equipment	36,768	-		36,768	15,406	2,269		17,675	19,094
8	1960	Miscellaneous Equipment	-	-		-				-	-
47	1965	Water Heater Rental Units	-	-		-				-	-
47	1970	Load Management controls	-	-		-				-	-
47	1975	Load Management Controls Utility Premises	-	-		-				-	-
47	1980	System Supervisory Equipment	283,068	19,675		302,743	79,807	19,527		99,333	203,409
47	1985	Sentinel Lighting Rental Units	-	-		-				-	-
47	1996	Hydro One S/S Contribution	-	-		-				-	-
47	1995	Contributions & Grants	- 3,524,304	- 998,564		- 4,522,868	- 509,625	- 161,510		- 671,135	- 3,851,734
		Total before Work in Process	**32,669,965**	**1,785,199**	**267,831**	**34,187,333**	**13,753,775**	**1,298,338**	**47,757**	**15,004,356**	**19,182,977**
WIP		Work in Process		-	-	-	-	-	-	-	-
		Total after Work in Process	**32,669,965**	**1,785,199**	**267,831**	**34,187,333**	**13,753,775**	**1,298,338**	**47,757**	**15,004,356**	**19,182,977**
			-	-	-		-	-	-		

10	1930	Transportation
8	1935	Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	52,056
Stores Equipment	171
Net Depreciation	1,246,111

excludes intangible plant $1,252

Table 2
Niagara-on-the-Lake Hydro Inc. Distribution & Operations
Fixed Asset Continuity Schedule as at December 31, 2007

Fixed Asset Continuity Schedule (Distribution & Operations)
As at December 31, 2007
(Excludes account 1606 - Intangible plant: cost $25,038, annual depreciation $1,252)

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	261,994			261,994	-			-	261,994
47	1808	Buildings - Substations	-			-	-			-	-
13	1810	Leasehold Improvements	-			-	-			-	-
47	1815	Transformer Station Equipment > 50 kV	4,996,118	185,536		5,181,654	318,267	127,222		445,489	4,736,165
47	1820	Substation Equipment	242,132			242,132	160,698	5,670		166,368	75,763
47	1825	Storage Battery Equipment	-			-	-			-	-
47	1830	Poles, Towers & Fixtures	4,200,601	62,417		4,263,018	2,293,653	134,464		2,428,117	1,834,901
47	1835	OH Conductors & Devices	5,518,153	211,383		5,729,536	2,875,445	181,073		3,056,518	2,673,018
47	1840	UG Conduit	3,596,713	90,517		3,687,229	1,313,255	141,942		1,455,197	2,232,033
47	1845	UG Conductors & Devices	6,970,580	117,699		7,088,280	2,836,218	273,041		3,109,259	3,979,021
47	1850	Line Transformers	6,393,146	299,682	21,271	6,671,557	2,649,377	232,878	21,271	2,860,983	3,810,574
47	1855	Services (OH & UG)	1,624,200	243,572		1,867,773	236,032	69,839		305,871	1,561,901
47	1860	Meters	1,032,961	25,125	18,557	1,039,529	556,116	35,703	9,592	582,228	457,301
47	1861	Smart Meters	-			-	-			-	-
N/A	1905	Land	49,000			49,000	-			-	49,000
CEC	1906	Land Rights	-			-	-			-	-
47	1908	Buildings & Fixtures	867,344	42,450		909,794	271,405	15,394		286,799	622,995
13	1910	Leasehold Improvements	-			-	-			-	-
8	1915	Office Furniture & Equipment	163,168	5,984		169,151	127,736	5,146		132,881	36,270
10	1920	Computer - Hardware up to Mar 22/04	233,047			233,047	222,645	6,101		228,746	4,301
45	1921	Computer - Hardware Mar 23/04 to Mar 19/07	38,938	14,380		53,318	10,148	9,226		19,374	33,944
45.1	1921	Computer - Hardware post Mar19/07	-	6,896		6,896	-	690		690	6,206
12	1925	Computer - Software	824,767	66,892		891,659	634,579	139,345		773,924	117,735
10	1930	Transportation Equipment	967,850	250,400	273,051	945,199	802,265	64,882	273,051	594,095	351,104
8	1935	Stores Equipment	14,235	1,804		16,039	14,055	261		14,316	1,723
8	1940	Tools, Shop & Garage Equipment	375,744	34,202		409,946	236,589	27,111		263,700	146,246
8	1945	Measurement & Testing Equipment	-			-	-			-	-
8	1950	Power operated Equipment	-			-	-			-	-
8	1955	Communications Equipment	36,768			36,768	17,675	2,269		19,944	16,825
8	1960	Miscellaneous Equipment	-			-	-			-	-
47	1965	Water Heater Rental Units	-			-	-			-	-
47	1970	Load Management controls	-			-	-			-	-
47	1975	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	System Supervisory Equipment	302,743	12,721		315,463	99,333	20,607		119,940	195,523
47	1985	Sentinel Lighting Rental Units	-			-	-			-	-
47	1996	Hydro One S/S Contribution	-			-	-			-	-
47	1995	Contributions & Grants	- 4,522,868	- 304,697		- 4,827,565	- 671,135	- 187,575		- 858,710	- 3,968,855
		Total before Work in Process	**34,187,333**	**1,366,963**	**312,880**	**35,241,416**	**15,004,356**	**1,305,288**	**303,915**	**16,005,729**	**19,235,687**
WIP		Work in Process	-	-	-	-	-	-	-	-	-
		Total after Work in Process	**34,187,333**	**1,366,963**	**312,880**	**35,241,416**	**15,004,356**	**1,305,288**	**303,915**	**16,005,729**	**19,235,687**
				-	-			-	-		

10	1930	Transportation
8	1935	Stores Equipment

Less: Fully Allocated Depreciation

Transportation	64,882
Stores Equipment	261
Net Depreciation	1,240,145

excludes intangible plant $1,252

Table 3
Niagara-on-the-Lake Hydro Inc. Distribution & Operations
Fixed Asset Continuity Schedule as at December 31, 2008

Fixed Asset Continuity Schedule (Distribution & Operations)
2008 Forecast
(Excludes account 1606 - Intangible plant: cost $25,038, annual depreciation $1,252)

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	261,994	-		261,994	-			-	261,994
47	1808	Buildings - Substations	-			-	-			-	-
13	1810	Leasehold Improvements	-			-	-			-	-
47	1815	Transformer Station Equipment > 50 kV	5,181,654	130,000		5,311,654	445,489	131,166		576,656	4,734,998
47	1820	Substation Equipment	242,132	-	- 28,320	270,452	166,368	4,755	18,253	152,871	117,581
47	1825	Storage Battery Equipment	-			-	-			-	-
47	1830	Poles, Towers & Fixtures	4,263,018	100,712		4,363,730	2,428,117	134,725		2,562,842	1,800,888
47	1835	OH Conductors & Devices	5,729,536	312,680		6,042,216	3,056,518	187,885		3,244,404	2,797,812
47	1840	UG Conduit	3,687,229	240,000		3,927,229	1,455,197	148,552		1,603,749	2,323,481
47	1845	UG Conductors & Devices	7,088,280	251,450		7,339,730	3,109,259	280,424		3,389,683	3,950,047
47	1850	Line Transformers	6,671,557	143,158		6,814,715	2,860,983	238,370		3,099,354	3,715,361
47	1855	Services (OH & UG)	1,867,773	100,000		1,967,773	305,871	76,711		382,582	1,585,190
47	1860	Meters	1,039,529	20,000		1,059,529	582,228	36,975		619,203	440,326
47	1861	Smart Meters	-			-	-			-	-
N/A	1905	Land	49,000	-		49,000	-			-	49,000
CEC	1906	Land Rights	-			-	-			-	-
47	1908	Buildings & Fixtures	909,794	25,000		934,794	286,799	16,068		302,867	631,927
13	1910	Leasehold Improvements	-			-	-			-	-
8	1915	Office Furniture & Equipment	169,151	5,000		174,151	132,881	5,695		138,576	35,575
10	1920	Computer - Hardware up to Mar 22/04	233,047			233,047	228,746	3,676		232,422	625
45	1921	Computer - Hardware Mar 23/04 to Mar 19/07	53,318			53,318	19,374	10,664		30,037	23,280
45.1	1921	Computer - Hardware post Mar19/07	6,896	15,000		21,896	690	2,879		3,569	18,327
12	1925	Computer - Software	891,659	50,000		941,659	773,924	76,903		850,827	90,832
10	1930	Transportation Equipment	945,199	30,000		975,199	594,095	83,532		677,627	297,572
8	1935	Stores Equipment	16,039	2,000		18,039	14,316	284		14,600	3,439
8	1940	Tools, Shop & Garage Equipment	409,946	5,000		414,946	263,700	28,575		292,274	122,672
8	1945	Measurement & Testing Equipment	-			-	-			-	-
8	1950	Power operated Equipment	-			-	-			-	-
8	1955	Communications Equipment	36,768	-		36,768	19,944	2,269		22,212	14,556
8	1960	Miscellaneous Equipment	-			-	-			-	-
47	1965	Water Heater Rental Units	-			-	-			-	-
47	1970	Load Management controls	-			-	-			-	-
47	1975	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	System Supervisory Equipment	315,463	10,000		325,463	119,940	21,364		141,304	184,159
47	1985	Sentinel Lighting Rental Units	-			-	-			-	-
47	1996	Hydro One S/S Contribution	-			-	-			-	-
47	1995	Contributions & Grants	- 4,827,565	- 150,000		- 4,977,565	- 858,710	- 196,200		- 1,054,910	- 3,922,655
		Total before Work in Process	**35,241,416**	**1,290,000**	**- 28,320**	**36,559,736**	**16,005,729**	**1,295,272**	**18,253**	**17,282,748**	**19,276,988**
WIP		Work in Process	-	-	-	-	-	-	-	-	-
		Total after Work in Process	**35,241,416**	**1,290,000**	**- 28,320**	**36,559,736**	**16,005,729**	**1,295,272**	**18,253**	**17,282,748**	**19,276,988**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation	83,532
Stores Equipment	284
Net Depreciation	1,211,456

excludes intangible plant $1,252

Table 4
Niagara-on-the-Lake Hydro Inc. Distribution & Operations
Fixed Asset Continuity Schedule as at December 31, 2009

Fixed Asset Continuity Schedule (Distribution & Operations)
2009 Test Year
(Excludes account 1606 - Intangible plant: cost $25,038, annual depreciation $1,252)

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land - Substations	261,994	40,000		301,994	-			-	301,994
47	1808	Buildings - Substations	-			-	-			-	-
13	1810	Leasehold Improvements	-			-	-			-	-
47	1815	Transformer Station Equipment > 50 kV	5,311,654	5,000		5,316,654	576,656	132,854		709,509	4,607,145
47	1820	Substation Equipment	270,452	-		270,452	152,871	3,141		156,012	114,440
47	1825	Storage Battery Equipment	-			-	-			-	-
47	1830	Poles, Towers & Fixtures	4,363,730	111,666		4,475,396	2,562,842	134,930		2,697,771	1,777,625
47	1835	OH Conductors & Devices	6,042,216	334,166		6,376,382	3,244,404	195,881		3,440,285	2,936,097
47	1840	UG Conduit	3,927,229	709,166		4,636,395	1,603,749	167,535		1,771,284	2,865,111
47	1845	UG Conductors & Devices	7,339,730	406,666		7,746,396	3,389,683	293,586		3,683,270	4,063,126
47	1850	Line Transformers	6,814,715	180,832		6,995,547	3,099,354	244,850		3,344,204	3,651,343
47	1855	Services (OH & UG)	1,967,773	100,000		2,067,773	382,582	80,711		463,293	1,604,479
47	1860	Meters	1,059,529	20,000		1,079,529	619,203	37,774		656,977	422,552
47	1861	Smart Meters	-			-	-			-	-
N/A	1905	Land	49,000	-		49,000	-			-	49,000
CEC	1906	Land Rights	-			-	-			-	-
47	1908	Buildings & Fixtures	934,794	20,000		954,794	302,867	16,518		319,385	635,409
13	1910	Leasehold Improvements	-			-	-			-	-
8	1915	Office Furniture & Equipment	174,151	5,000		179,151	138,576	6,111		144,687	34,464
10	1920	Computer - Hardware up to Mar 22/04	233,047			233,047	232,422	625		233,047	0
45	1921	Computer - Hardware Mar 23/04 to Mar 19/07	53,318			53,318	30,037	9,983		40,021	13,297
45.1	1921	Computer - Hardware post Mar19/07	21,896	10,000		31,896	3,569	5,379		8,948	22,948
12	1925	Computer - Software	941,659	50,000		991,659	850,827	63,017		913,844	77,815
10	1930	Transportation Equipment	975,199	-		975,199	677,627	86,361		763,987	211,212
8	1935	Stores Equipment	18,039	20,000		38,039	14,600	1,384		15,984	22,055
8	1940	Tools, Shop & Garage Equipment	414,946	5,000		419,946	292,274	28,191		320,465	99,481
8	1945	Measurement & Testing Equipment	-			-	-			-	-
8	1950	Power operated Equipment	-			-	-			-	-
8	1955	Communications Equipment	36,768	-		36,768	22,212	2,269		24,481	12,287
8	1960	Miscellaneous Equipment	-			-	-			-	-
47	1965	Water Heater Rental Units	-			-	-			-	-
47	1970	Load Management controls	-			-	-			-	-
47	1975	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	System Supervisory Equipment	325,463	10,000		335,463	141,304	22,031		163,335	172,128
47	1985	Sentinel Lighting Rental Units	-			-	-			-	-
47	1996	Hydro One S/S Contribution	-			-	-			-	-
47	1995	Contributions & Grants	- 4,977,565	- 150,000		- 5,127,565	- 1,054,910	- 201,454		- 1,256,364	- 3,871,201
		Total before Work in Process	**36,559,736**	**1,877,496**	**-**	**38,437,232**	**17,282,748**	**1,331,677**	**-**	**18,614,426**	**19,822,807**
WIP		Work in Process	-	-	-	-	-	-	-	-	-
		Total after Work in Process	**36,559,736**	**1,877,496**	**-**	**38,437,232**	**17,282,748**	**1,331,677**	**-**	**18,614,426**	**19,822,807**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation	86,361
Stores Equipment	1,384
Net Depreciation	1,243,933

excludes intangible plant $1,252

GROSS ASSETS TABLE:

Table 1
Gross Assets

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board Approved	2007 Actual ($)	Variance from 2006 Actual	2008 Bridge ($)	Variance from 2007 Actual	2009 Test ($)	Variance from 2008 Bridge
Land and Buildings									
1805-Land	198,798	261,994	63,196	261,994		261,994		301,994	40,000
1806-Land Rights									
1808-Buildings and Fixtures									
1905-Land	49,000	49,000		49,000		49,000		49,000	
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings	**247,798**	**310,994**	**63,196**	**310,994**		**310,994**		**350,994**	**40,000**
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV	3,772,989	4,996,118	1,223,130	5,181,654	185,536	5,311,654	130,000	5,316,654	5,000
Sub-Total-TS Primary Above 50	**3,772,989**	**4,996,118**	**1,223,130**	**5,181,654**	**185,536**	**5,311,654**	**130,000**	**5,316,654**	**5,000**
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	263,416	242,132	(21,284)	242,132		270,452	28,320	270,452	
Sub-Total-DS	**263,416**	**242,132**	**(21,284)**	**242,132**		**270,452**	**28,320**	**270,452**	
Poles and Wires									
1830-Poles, Towers and Fixtures	3,783,277	4,200,601	417,324	4,263,018	62,417	4,363,730	100,712	4,475,396	111,666
1835-Overhead Conductors and Devices	4,867,178	5,518,153	650,975	5,729,536	211,383	6,042,216	312,680	6,376,382	334,166
1840-Underground Conduit	2,875,314	3,596,713	721,399	3,687,229	90,517	3,927,229	240,000	4,636,395	709,166
1845-Underground Conductors and Devices	6,173,558	6,970,580	797,022	7,088,280	117,699	7,339,730	251,450	7,746,396	406,666
Sub-Total-Poles and Wires	**17,699,327**	**20,286,047**	**2,586,720**	**20,768,063**	**482,016**	**21,672,905**	**904,842**	**23,234,569**	**1,561,664**
Line Transformers									
1850-Line Transformers	5,435,678	6,393,146	957,468	6,671,557	278,411	6,814,715	143,158	6,995,547	180,832
Sub-Total-Line Transformers	**5,435,678**	**6,393,146**	**957,468**	**6,671,557**	**278,411**	**6,814,715**	**143,158**	**6,995,547**	**180,832**
Services and Meters									
1855-Services	1,026,410	1,624,200	597,791	1,867,773	243,572	1,967,773	100,000	2,067,773	100,000
1860-Meters	910,741	1,032,961	122,220	1,039,529	6,568	1,059,529	20,000	1,079,529	20,000
1861-Smart Meters									
Sub-Total-Services and Meters	**1,937,151**	**2,657,161**	**720,010**	**2,907,301**	**250,140**	**3,027,301**	**120,000**	**3,147,301**	**120,000**
General Plant									
1908-Buildings and Fixtures	845,593	867,344	21,751	909,794	42,450	934,794	25,000	954,794	20,000
1910-Leasehold Improvements									
Sub-Total-General Plant	**845,593**	**867,344**	**21,751**	**909,794**	**42,450**	**934,794**	**25,000**	**954,794**	**20,000**
IT Assets									
1920-Computer Equipment - Hardware	233,324	233,047	(277)	233,047		233,047		233,047	
1921-Computer Equipment - Hardware post March 22, 2004		38,938	38,938	60,214	21,275	75,214	15,000	85,214	10,000
1925-Computer Software	501,482	824,767	323,285	891,659	66,892	941,659	50,000	991,659	50,000
Sub-Total-IT Assets	**734,806**	**1,096,752**	**361,946**	**1,184,920**	**88,168**	**1,249,920**	**65,000**	**1,309,920**	**60,000**
Equipment									
1915-Office Furniture and Equipment	134,769	163,168	28,398	169,151	5,984	174,151	5,000	179,151	5,000
1930-Transportation Equipment	1,004,612	967,850	(36,761)	945,199	(22,651)	975,199	30,000	975,199	
1935-Stores Equipment	14,235	14,235		16,039	1,804	18,039	2,000	38,039	20,000
1940-Tools, Shop and Garage Equipment	342,079	375,744	33,665	409,946	34,202	414,946	5,000	419,946	5,000
1945-Measurement and Testing Equipment									
1950-Power Operated Equipment									
1955-Communication Equipment	14,428	36,768	22,340	36,768		36,768		36,768	
1960-Miscellaneous Equipment									
Sub-Total-Equipment	**1,510,124**	**1,557,766**	**47,642**	**1,577,103**	**19,338**	**1,619,103**	**42,000**	**1,649,103**	**30,000**
Other Distribution Assets									
1825-Storage Battery Equipment									
1970-Load Management Controls - Customer Premises									
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	159,922	302,743	142,820	315,463	12,721	325,463	10,000	335,463	10,000
1985-Sentinel Lighting Rental Units									
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(2,802,684)	(4,522,868)	(1,720,184)	(4,827,565)	(304,697)	(4,977,565)	(150,000)	(5,127,565)	(150,000)
1996-Hydro One S/S Contribution									
Sub-Total-Other Distribution Assets	**(2,642,762)**	**(4,220,126)**	**(1,577,364)**	**(4,512,101)**	**(291,976)**	**(4,652,101)**	**(140,000)**	**(4,792,101)**	**(140,000)**
GROSS ASSET TOTAL	**29,804,120**	**34,187,333**	**4,383,214**	**35,241,416**	**1,054,083**	**36,559,736**	**1,318,320**	**38,437,232**	**1,877,496**

VARIANCE ANALYSIS ON GROSS ASSETS:

Table 1 below identifies the material year-to-year variances based on the materiality thresholds in **Exhibit 2, Tab 1, Schedule 2**. The variance for each account is tested individually against the threshold to determine its materiality.

Table 1
Gross Assets - Material Variances

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Land and Buildings									
1805-Land	198,798	261,994	0	261,994	0	261,994	0	301,994	0
1806-Land Rights			0		0		0		0
1808-Buildings and Fixtures		0	0	0	0	0	0	0	0
1905-Land	49,000	49,000	0	49,000	0	49,000	0	49,000	0
1906-Land Rights		0	0	0	0	0	0	0	0
1810-Leasehold Improvements		0	0	0	0	0	0	0	0
Sub-Total-Land and Buildings	**247,798**	**310,994**	**0**	**310,994**	**0**	**310,994**	**0**	**350,994**	**0**
TS Primary Above 50									0
1815-Transformer Station Equipment - Normally Primary above 50 kV	3,772,989	4,996,118	1,223,130	5,181,654	0	5,311,654	0	5,316,654	0
Sub-Total-TS Primary Above 50	**3,772,989**	**4,996,118**	**1,223,130**	**5,181,654**	**0**	**5,311,654**	**0**	**5,316,654**	**0**
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	263,416	242,132	0	242,132	0	270,452	0	270,452	0
Sub-Total-DS	**263,416**	**242,132**	**0**	**242,132**	**0**	**270,452**	**0**	**270,452**	**0**
Poles and Wires									
1830-Poles, Towers and Fixtures	3,783,277	4,200,601	417,324	4,263,018	0	4,363,730	0	4,475,396	0
1835-Overhead Conductors and Devices	4,867,178	5,518,153	650,975	5,729,536	211,383	6,042,216	312,680	6,376,382	334,166
1840-Underground Conduit	2,875,314	3,596,713	721,399	3,687,229	0	3,927,229	240,000	4,636,395	709,166
1845-Underground Conductors and Devices	6,173,558	6,970,580	797,022	7,088,280	0	7,339,730	251,450	7,746,396	406,666
Sub-Total-Poles and Wires	**17,699,327**	**20,286,047**	**2,586,720**	**20,768,063**	**211,383**	**21,672,905**	**804,130**	**23,234,569**	**1,449,998**
Line Transformers									
1850-Line Transformers	5,435,678	6,393,146	957,468	6,671,557	278,411	6,814,715	0	6,995,547	0
Sub-Total-Line Transformers	**5,435,678**	**6,393,146**	**957,468**	**6,671,557**	**278,411**	**6,814,715**	**0**	**6,995,547**	**0**
Services and Meters									
1855-Services	1,026,410	1,624,200	597,791	1,867,773	243,572	1,967,773	0	2,067,773	0
1860-Meters	910,741	1,032,961	0	1,039,529	0	1,059,529	0	1,079,529	0
1861-Smart Meters	0	0	0	0	0	0	0	0	0
Sub-Total-Services and Meters	**1,937,151**	**2,657,161**	**597,791**	**2,907,301**	**243,572**	**3,027,301**	**0**	**3,147,301**	**0**
General Plant									
1908-Buildings and Fixtures	845,593	867,344	0	909,794	0	934,794	0	954,794	0
1910-Leasehold Improvements	0	0	0	0	0	0	0	0	0
Sub-Total-General Plant	**845,593**	**867,344**	**0**	**909,794**	**0**	**934,794**	**0**	**954,794**	**0**
IT Assets									
1920-Computer Equipment - Hardware	233,324	233,047	0	233,047	0	233,047	0	233,047	0
1921-Computer Equipment - Hardware post March 22, 2004	0	38,938	0	60,214	0	75,214	0	85,214	0
1925-Computer Software	501,482	824,767	323,285	891,659	0	941,659	0	991,659	0
Sub-Total-IT Assets	**734,806**	**1,096,752**	**323,285**	**1,184,920**	**0**	**1,249,920**	0	**1,309,920**	**0**
Equipment									
1915-Office Furniture and Equipment	134,769	163,168	0	169,151	0	174,151	0	179,151	0
1930-Transportation Equipment	1,004,612	967,850	0	945,199	0	975,199	0	975,199	0
1935-Stores Equipment	14,235	14,235	0	16,039	0	18,039	0	38,039	0
1940-Tools, Shop and Garage Equipment	342,079	375,744	0	409,946	0	414,946	0	419,946	0
1945-Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
1950-Power Operated Equipment		0	0	0	0	0	0	0	0
1955-Communication Equipment	14,428	36,768	0	36,768	0	36,768	0	36,768	0
1960-Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
Sub-Total-Equipment	**1,510,124**	**1,557,766**	**0**	**1,577,103**	**0**	**1,619,103**	**0**	**1,649,103**	**0**
Other Distribution Assets									
1825-Storage Battery Equipment		0	0	0	0	0	0	0	0
1970-Load Management Controls - Customer Premises		0	0	0	0	0	0	0	0
1975-Load Management Controls - Utility Premises		0	0	0	0	0	0	0	0
1980-System Supervisory Equipment	159,922	302,743	0	315,463	0	325,463	0	335,463	0
1985-Sentinel Lighting Rental Units		0	0	0	0	0	0	0	0
1990-Other Tangible Property			0		0		0		0
1995-Contributions and Grants - Credit	(2,802,684)	(4,522,868)	(1,720,184)	(4,827,565)	(304,697)	(4,977,565)	0	(5,127,565)	0
1996-Hydro One S/S Contribution		0	0	0	0	0	0	0	0
Sub-Total-Other Distribution Assets	**(2,642,762)**	**(4,220,126)**	**(1,720,184)**	**(4,512,101)**	**(304,697)**	**(4,652,101)**	**0**	**(4,792,101)**	**0**
GROSS ASSET TOTAL	**29,804,120**	**34,187,333**	**3,968,210**	**35,241,416**	**428,670**	**36,559,736**	**804,130**	**38,437,232**	**1,449,998**

Explanations of the material variances are provided below:

(The materiality analysis for capital projects which exceed the threshold for the 2009 Test Year is provided in **Exhibit 2, Tab 3, Schedule 2**).

TS Primary Above 50

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
TS Primary Above 50									0
1815-Transformer Station Equipment - Normally Primary above 50 kV	3,772,989	4,996,118	1,223,130	5,181,654	0	5,311,654	0	5,316,654	0
Sub-Total-TS Primary Above 50	**3,772,989**	**4,996,118**	**1,223,130**	**5,181,654**	**0**	**5,311,654**	**0**	**5,316,654**	**0**

- *Account 1815 – 2006 Actual vs. 2006 Approved*

  As indicated in the 2006 rate application, NOTL Hydro purchased a transformer station from Hydro One with an in-service date of 2005 and cost to account 1815 of $2,130,000. In accordance with the 2006 OEB rate model, only 50% of this cost was reflected in the approved 2006 amount. The actual 2006 amount includes 100% of this cost.

Poles and Wires

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Poles and Wires									
1830-Poles, Towers and Fixtures	3,783,277	4,200,601	417,324	4,263,018	0	4,363,730	0	4,475,396	0
1835-Overhead Conductors and Devices	4,867,178	5,518,153	650,975	5,729,536	211,383	6,042,216	312,680	6,376,382	334,166
1840-Underground Conduit	2,875,314	3,596,713	721,399	3,687,229	0	3,927,229	240,000	4,636,395	709,166
1845-Underground Conductors and Devices	6,173,558	6,970,580	797,022	7,088,280	0	7,339,730	251,450	7,746,396	406,666
Sub-Total-Poles and Wires	**17,699,327**	**20,286,047**	**2,586,720**	**20,768,063**	**211,383**	**21,672,905**	**804,130**	**23,234,569**	**1,449,998**

- *Accounts 1830, 1835, 1840 and 1845 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amounts for each account are calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years investment in poles and wires through to the 2006 actual amounts are not reflected in the 2006 Board approved amounts.

- *Account 1835 – 2007 Actual vs. 2006 Actual*

The variances in this account result from the investments in conductors and ancillary devices associated with system enhancement projects as part of our overhead capital program. These Projects include: Queenston Road Upgrade ($35,206), York Road Upgrade ($91,790), Hwy 55 to Stewart Road ($47,230), Miscellaneous Projects ($9,062), Supervision of Overhead Projects ($18,353), Customer Projects ($3,839) and associated burden costs ($5,903).

- *Account 1835 – 2008 Bridge vs. 2007 Actual*

The variances in this account result from the investments in conductors and ancillary devices associated with system enhancement projects as part of our overhead capital program. These Projects include: Queenston Road Upgrade ($131,630), York Road Upgrade ($70,000), Queenston Village Restoration ($20,000), Concession 5 Upgrade ($40,000), Supervision of Overhead Projects ($20,000), Miscellaneous Projects ($6,050) and Capital Customer Projects ($25,000).

- *Account 1835 – 2009 Test vs. 2008 Bridge*

The variances in this account result from the investments in the system enhancement and expansion projects as part of our overhead capital program. These Projects include: Queenston Road Upgrade (150,000), York Road Upgrade ($10,000), Concession 7 tie to East West Line ($115,000), Supervision of Overhead Projects ($21,666), Miscellaneous Projects ($12,500) and Capital Customer Projects ($25,000).

- *Account 1840 – 2008 Bridge vs. 2007 Actual*

  The majority of the variances in this account pertain to the Chautauqua Project as part of our underground capital program ($135,000). Other projects associated with this account are New Connections ($55,000), Miscellaneous Projects ($5,000), Supervision of Underground Projects ($20,000) and Capital Customer Projects ($25,000).

- *Account 1840 – 2009 Test vs. 2008 Bridge*

  The majority of the variances in this account pertain to the Chautauqua Project as part of our underground capital program ($600,000). Other projects associated with this account are New Connections ($55,000), Miscellaneous Projects ($7,500), Supervision of Underground Projects ($21,666) and Capital Customer Projects ($25,000).

- *Account 1845 – 2008 Bridge vs. 2007 Actual*

  The majority of the variances in this account pertain to the system enhancement Chautauqua Project as part of our underground capital program ($135,000). Other projects associated with this account are New Connections ($55,000), Miscellaneous Projects ($16,450), Supervision of Underground Projects ($20,000) and Capital Customer Projects ($25,000).

- *Account 1845 –2009 Test vs. 2008 Bridge*

  The majority of the variances in this account pertain to the system enhancement Chautauqua Project as part of our underground capital program ($300,000). Other projects associated with this account are New Connections ($55,000), Miscellaneous Projects ($5,000), Supervision of Underground Projects ($21,666), and Capital Customer Projects ($25,000).

Line Transformers

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Line Transformers									
1850-Line Transformers	5,435,678	6,393,146	957,468	6,671,557	278,411	6,814,715	0	6,995,547	0
Sub-Total-Line Transformers	**5,435,678**	**6,393,146**	**957,468**	**6,671,557**	**278,411**	**6,814,715**	**0**	**6,995,547**	**0**

- *Account 1850 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amount is calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years normal investment in line transformers through to the 2006 actual amounts are not reflected in the 2006 Board approved amounts.

- *Account 1850 – 2007 Actual vs. 2006 Actual*

The variance in this account results from the investment in transformers associated with system enhancement projects as part of our overhead capital program and other activities. Projects include: Queenston Road Upgrade ($4,785), York Road Upgrade ($9,056), Miscellaneous Overhead and Underground Projects ($27,887), Supervision of Overhead Projects ($13,507), Customer Projects ($91,819), Queenston Village Project ($32,120), Chautauqua Project ($351), Supervision Underground Projects ($35,005), Subdivisions ($64,220), Burden costs ($5,366). Other activities affecting the variance are: transformer disposals ($-21,271), a change in overall transformer inventory ($2,419) and an increase in damaged and repaired transformers due to failures related to inclement weather and other damages ($12,955).

Services and Meters

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Services and Meters									
1855-Services	1,026,410	1,624,200	597,791	1,867,773	243,572	1,967,773	0	2,067,773	0
1860-Meters	910,741	1,032,961	0	1,039,529	0	1,059,529	0	1,079,529	0
1861-Smart Meters	0	0	0	0	0	0	0	0	0
Sub-Total-Services and Meters	**1,937,151**	**2,657,161**	**597,791**	**2,907,301**	**243,572**	**3,027,301**	**0**	**3,147,301**	**0**

- *Account 1855 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amount is calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years normal investments in services through to the 2006 actual amount are not reflected in the 2006 Board approved amounts.

- *Account 1855 – 2007 Actual vs. 2006 Actual*

The additional investment relates to new residential customer servicing, and new general service connections. Costs associated with this account are underground services ($207,717), overhead services ($25,602) and burden costs ($10,253).

IT Assets

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
IT Assets									
1920-Computer Equipment - Hardware	233,324	233,047	0	233,047	0	233,047	0	233,047	0
1921-Computer Equipment - Hardware post March 22, 2004	0	38,938	0	60,214	0	75,214	0	85,214	0
1925-Computer Software	501,482	824,767	323,285	891,659	0	941,659	0	991,659	0
Sub-Total-IT Assets	**734,806**	**1,096,752**	**323,285**	**1,184,920**	**0**	**1,249,920**	0	**1,309,920**	**0**

- *Account 1925 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amount is calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. Thus, the 2006 Board approved amount does not reflect over 2 years of investment made by NOTL Hydro in a new integrated customer information, billing and financial system, through to the 2006 actual.

Other Distribution Assets – Contributions and Grants

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Other Distribution Assets									
1825-Storage Battery Equipment		0	0	0	0	0	0	0	0
1970-Load Management Controls - Customer Premises		0	0	0	0	0	0	0	0
1975-Load Management Controls - Utility Premises		0	0	0	0	0	0	0	0
1980-System Supervisory Equipment	159,922	302,743	0	315,463	0	325,463	0	335,463	0
1985-Sentinel Lighting Rental Units		0	0	0	0	0	0	0	0
1990-Other Tangible Property			0		0		0		0
1995-Contributions and Grants - Credit	(2,802,684)	(4,522,868)	(1,720,184)	(4,827,565)	(304,697)	(4,977,565)	0	(5,127,565)	0
1996-Hydro One S/S Contribution		0	0	0	0	0	0	0	0
Sub-Total-Other Distribution Assets	**(2,642,762)**	**(4,220,126)**	**(1,720,184)**	**(4,512,101)**	**(304,697)**	**(4,652,101)**	**0**	**(4,792,101)**	**0**

- *Account 1995 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amount is calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years normal contributions through to the 2006 actual amount are not reflected in the 2006 Board approved amounts.

- *Account 1995 – 2007 Actual vs. 2006 Actual*

The variance pertains to a general increase in customer driven capital system expansion and enhancement requirements. Costs associated with this account are Overhead Contributions (-13,780), Underground Contributions (-$171,117), Transformer Contributions (-$119,600), and Meter Contributions (-$200).

ACCUMULATED DEPRECIATION

Table 1
Accumulated Depreciation

Description	2006 Board Approved ($)	2006 Actual ($)	Variance from 2006 Board	2007 Actual ($)	Variance from 2006	2008 Bridge ($)	Variance from 2007	2009 Test ($)	Variance from 2008
Land and Buildings									
1805-Land									
1806-Land Rights									
1808-Buildings and Fixtures									
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings									
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV	67,705	318,267	250,562	445,489	127,222	576,656	131,166	709,509	132,854
Sub-Total-TS Primary Above 50	**67,705**	**318,267**	**250,562**	**445,489**	**127,222**	**576,656**	**131,166**	**709,509**	**132,854**
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	166,771	160,698	(6,073)	166,368	5,670	152,871	(13,498)	156,012	3,141
Sub-Total-DS	**166,771**	**160,698**	**(6,073)**	**166,368**	**5,670**	**152,871**	**(13,498)**	**156,012**	**3,141**
Poles and Wires									
1830-Poles, Towers and Fixtures	2,830,629	2,293,653	(536,976)	2,428,117	134,464	2,562,842	134,725	2,697,771	134,930
1835-Overhead Conductors and Devices	1,611,063	2,875,445	1,264,382	3,056,518	181,073	3,244,404	187,885	3,440,285	195,881
1840-Underground Conduit	728,629	1,313,255	584,626	1,455,197	141,942	1,603,749	148,552	1,771,284	167,535
1845-Underground Conductors and Devices	2,476,268	2,836,218	359,950	3,109,259	273,041	3,389,683	280,424	3,683,270	293,586
Sub-Total-Poles and Wires	**7,646,589**	**9,318,571**	**1,671,982**	**10,049,091**	**730,520**	**10,800,677**	**751,586**	**11,592,610**	**791,932**
Line Transformers									
1850-Line Transformers	2,189,717	2,649,377	459,659	2,860,983	211,607	3,099,354	238,370	3,344,204	244,850
Sub-Total-Line Transformers	**2,189,717**	**2,649,377**	**459,659**	**2,860,983**	**211,607**	**3,099,354**	**238,370**	**3,344,204**	**244,850**
Services and Meters									
1855-Services	103,830	236,032	132,202	305,871	69,839	382,582	76,711	463,293	80,711
1860-Meters	473,587	556,116	82,529	582,228	26,111	619,203	36,975	656,977	37,774
1861-Smart Meters									
Sub-Total-Services and Meters	**577,417**	**792,148**	**214,731**	**888,099**	**95,951**	**1,001,785**	**113,686**	**1,120,270**	**118,485**
General Plant									
1908-Buildings and Fixtures	234,402	271,405	37,003	286,799	15,394	302,867	16,068	319,385	16,518
1910-Leasehold Improvements									
Sub-Total-General Plant	**234,402**	**271,405**	**37,003**	**286,799**	**15,394**	**302,867**	**16,068**	**319,385**	**16,518**
IT Assets									
1920-Computer Equipment - Hardware	184,974	222,645	37,671	228,746	6,101	232,422	3,676	233,047	625
1921-Computer Equipment - Hardware post March 22, 2004		10,148	10,148	20,063	9,915	33,606	13,543	48,968	15,362
1925-Computer Software	232,510	634,579	402,069	773,924	139,345	850,827	76,903	913,844	63,017
Sub-Total-IT Assets	**417,484**	**867,372**	**449,888**	**1,022,734**	**155,361**	**1,116,855**	**94,121**	**1,195,859**	**79,004**
Equipment									
1915-Office Furniture and Equipment	118,027	127,736	9,709	132,881	5,146	138,576	5,695	144,687	6,111
1930-Transportation Equipment	762,075	802,265	40,189	594,095	(208,169)	677,627	83,532	763,987	86,361
1935-Stores Equipment	12,716	14,055	1,339	14,316	261	14,600	284	15,984	1,384
1940-Tools, Shop and Garage Equipment	184,501	236,589	52,088	263,700	27,111	292,274	28,575	320,465	28,191
1945-Measurement and Testing Equipment									
1950-Power Operated Equipment									
1955-Communication Equipment	8,477	17,675	9,197	19,944	2,269	22,212	2,269	24,481	2,269
1960-Miscellaneous Equipment									
Sub-Total-Equipment	**1,085,796**	**1,198,319**	**112,523**	**1,024,936**	**(173,383)**	**1,145,290**	**120,354**	**1,269,605**	**124,315**
Other Distribution Assets									
1825-Storage Battery Equipment									
1970-Load Management Controls - Customer Premises									
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	59,305	99,333	40,029	119,940	20,607	141,304	21,364	163,335	22,031
1985-Sentinel Lighting Rental Units									
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	(321,126)	(671,135)	(350,009)	(858,710)	(187,575)	(1,054,910)	(196,200)	(1,256,364)	(201,454)
1996-Hydro One S/S Contribution									
Sub-Total-Other Distribution Assets	**(261,821)**	**(571,801)**	**(309,980)**	**(738,769)**	**(166,968)**	**(913,606)**	**(174,836)**	**(1,093,029)**	**(179,423)**
ACCUMULATED DEPRECIATION TOTAL	**12,124,061**	**15,004,356**	**2,880,295**	**16,005,729**	**1,001,373**	**17,282,748**	**1,277,019**	**18,614,426**	**1,331,677**

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION:

Table 1 below identifies the material year-to-year variances based on the materiality thresholds in **Exhibit 2, Tab 1, Schedule 2**:

Table 1
Accumulated Depreciation Material Variances

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Land and Buildings									
1805-Land									
1806-Land Rights									
1808-Buildings and Fixtures									
1905-Land									
1906-Land Rights									
1810-Leasehold Improvements									
Sub-Total-Land and Buildings	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV	67,705	318,267	250,562	445,489	0	576,656	0	709,509	0
Sub-Total-TS Primary Above 50	**67,705**	**318,267**	**250,562**	**445,489**	**0**	**576,656**	**0**	**709,509**	**0**
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	166,771	160,698	0	166,368	0	152,871	0	156,012	0
Sub-Total-DS	**166,771**	**160,698**	**0**	**166,368**	**0**	**152,871**	**0**	**156,012**	**0**
Poles and Wires									
1830-Poles, Towers and Fixtures	2,830,629	2,293,653	(536,976)	2,428,117	0	2,562,842	0	2,697,771	0
1835-Overhead Conductors and Devices	1,611,063	2,875,445	1,264,382	3,056,518	0	3,244,404	0	3,440,285	0
1840-Underground Conduit	728,629	1,313,255	584,626	1,455,197	0	1,603,749	0	1,771,284	0
1845-Underground Conductors and Devices	2,476,268	2,836,218	359,950	3,109,259	273,041	3,389,683	280,424	3,683,270	293,586
Sub-Total-Poles and Wires	**7,646,589**	**9,318,571**	**1,671,982**	**10,049,091**	**273,041**	**10,800,677**	**280,424**	**11,592,610**	**293,586**
Line Transformers									
1850-Line Transformers	2,189,717	2,649,377	459,659	2,860,983	211,607	3,099,354	238,370	3,344,204	244,850
Sub-Total-Line Transformers	**2,189,717**	**2,649,377**	**459,659**	**2,860,983**	**211,607**	**3,099,354**	**238,370**	**3,344,204**	**244,850**
Services and Meters									
1855-Services	103,830	236,032	0	305,871	0	382,582	0	463,293	0
1860-Meters	473,587	556,116	0	582,228	0	619,203	0	656,977	0
1861-Smart Meters	0	0	0	0	0	0	0	0	0
Sub-Total-Services and Meters	**577,417**	**792,148**	**0**	**888,099**	**0**	**1,001,785**	**0**	**1,120,270**	**0**
General Plant									
1908-Buildings and Fixtures	234,402	271,405	0	286,799	0	302,867	0	319,385	0
1910-Leasehold Improvements	0	0	0	0	0	0	0	0	0
Sub-Total-General Plant	**234,402**	**271,405**	**0**	**286,799**	**0**	**302,867**	**0**	**319,385**	**0**
IT Assets									
1920-Computer Equipment - Hardware	184,974	222,645	0	228,746	0	232,422	0	233,047	0
1921-Computer Equipment - Hardware post March 22, 2004		10,148	0	20,063	0	33,606	0	48,968	0
1925-Computer Software	232,510	634,579	402,069	773,924	0	850,827	0	913,844	0
Sub-Total-IT Assets	**417,484**	**867,372**	**402,069**	**1,022,734**	**0**	**1,116,855**	**0**	**1,195,859**	**0**
Equipment									
1915-Office Furniture and Equipment	118,027	127,736	0	132,881	0	138,576	0	144,687	0
1930-Transportation Equipment	762,075	802,265	0	594,095	(208,169)	677,627	0	763,987	0
1935-Stores Equipment	12,716	14,055	0	14,316	0	14,600	0	15,984	0
1940-Tools, Shop and Garage Equipment	184,501	236,589	0	263,700	0	292,274	0	320,465	0
1945-Measurement and Testing Equipment		0	0	0	0	0	0	0	0
1950-Power Operated Equipment		0	0	0	0	0	0	0	0
1955-Communication Equipment	8,477	17,675	0	19,944	0	22,212	0	24,481	0
1960-Miscellaneous Equipment		0	0	0	0	0	0	0	0
Sub-Total-Equipment	**1,085,796**	**1,198,319**	**0**	**1,024,936**	**(208,169)**	**1,145,290**	**0**	**1,269,605**	**0**
Other Distribution Assets									
1825-Storage Battery Equipment		0	0	0	0	0	0	0	0
1970-Load Management Controls - Customer Premises		0	0	0	0	0	0	0	0
1975-Load Management Controls - Utility Premises		0	0	0	0	0	0	0	0
1980-System Supervisory Equipment	59,305	99,333	0	119,940	0	141,304	0	163,335	0
1985-Sentinel Lighting Rental Units		0	0	0	0	0	0	0	0
1990-Other Tangible Property			0		0		0		0
1995-Contributions and Grants - Credit	(321,126)	(671,135)	(350,009)	(858,710)	0	(1,054,910)	(196,200)	(1,256,364)	(201,454)
1996-Hydro One S/S Contribution		0	0	0	0	0	0	0	0
Sub-Total-Other Distribution Assets	**(261,821)**	**(571,801)**	**(350,009)**	**(738,769)**	**0**	**(913,606)**	**(196,200)**	**(1,093,029)**	**(201,454)**
ACCUMULATED DEPRECIATION TOTAL	**12,124,061**	**15,004,356**	**2,434,264**	**16,005,729**	**276,478**	**17,282,748**	**322,594**	**18,614,426**	**336,983**

Explanations of the material variances in accumulated depreciation related to the asset accounts indicated are provided below:

Accumulated Depreciation - TS Primary Above 50

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV	67,705	318,267	250,562	445,489	0	576,656	0	709,509	0
Sub-Total-TS Primary Above 50	**67,705**	**318,267**	**250,562**	**445,489**	**0**	**576,656**	**0**	**709,509**	**0**

- *Account 1815 – 2006 Actual vs. 2006 Approved*

The 2006 approved amount for accumulated depreciation was calculated in the 2006 OEB rate model as the average of the 2003 and 2004 actual balances (together with any applicable Tier 1 adjustments). NOTL Hydro's actual assets in account 1815 were a transformer station constructed with an in-service date of 2003 and another station purchased with an in-service date of 2005. As such, the variance is due to the 2006 approved accumulated depreciation only including a partial amount for the 2003 in-service station and nil for the 2005 in-service station, whereas the 2006 actual amount includes the full amount of the depreciation for both stations from their in-service dates.

Accumulated Depreciation - Poles and Wires

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Poles and Wires									
1830-Poles, Towers and Fixtures	2,830,629	2,293,653	(536,976)	2,428,117	0	2,562,842	0	2,697,771	0
1835-Overhead Conductors and Devices	1,611,063	2,875,445	1,264,382	3,056,518	0	3,244,404	0	3,440,285	0
1840-Underground Conduit	728,629	1,313,255	584,626	1,455,197	0	1,603,749	0	1,771,284	0
1845-Underground Conductors and Devices	2,476,268	2,836,218	359,950	3,109,259	273,041	3,389,683	280,424	3,683,270	293,586
Sub-Total-Poles and Wires	**7,646,589**	**9,318,571**	**1,671,982**	**10,049,091**	**273,041**	**10,800,677**	**280,424**	**11,592,610**	**293,586**

- *Accounts 1830, 1835, 1840 and 1845 – 2006 Actual vs. 2006 Approved*

The variances in these accounts are due to two factors. First, the 2006 Board approved amounts for each account are calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years normal depreciation in poles and wires through to the 2006 actual amounts are not reflected in the 2006 Board approved amounts. Secondly, in fiscal 2004, transfers of accumulated depreciation amounts were done between accumulated depreciation accounts (from 1830 to 1835, and from 1845 to 1840) to correct recording errors that had occurred in prior years.

- *Account 1845 – 2007 Actual vs. 2006 Actual, and*

  – 2008 Bridge vs. 2007 Actual, and

  – 2009 Test vs. 2008 Bridge

The variance in these years results from the amortization expense for the poles and wires asset account in those years.

Accumulated Depreciation - Line Transformers

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Line Transformers									
1850-Line Transformers	2,189,717	2,649,377	459,659	2,860,983	211,607	3,099,354	238,370	3,344,204	244,850
Sub-Total-Line Transformers	**2,189,717**	**2,649,377**	**459,659**	**2,860,983**	**211,607**	**3,099,354**	**238,370**	**3,344,204**	**244,850**

- *Account 1850 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amounts for each account are calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years normal depreciation in line transformers through to the 2006 actual amount are not reflected in the 2006 Board approved amount.

- *Account 1850 – 2007 Actual vs. 2006 Actual, and*

  – 2008 Bridge vs. 2007 Actual, and

  – 2009 Test vs. 2008 Bridge

The variance in these years results from the amortization expense for the line transformers asset account in those years (net of removal of accumulated depreciation for disposals in 2006 and 2007).

Accumulated Depreciation - IT Assets

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
IT Assets									
1920-Computer Equipment - Hardware	184,974	222,645	0	228,746	0	232,422	0	233,047	0
1921-Computer Equipment - Hardware post March 22, 2004		10,148	0	20,063	0	33,606	0	48,968	0
1925-Computer Software	232,510	634,579	402,069	773,924	0	850,827	0	913,844	0
Sub-Total-IT Assets	**417,484**	**867,372**	**402,069**	**1,022,734**	**0**	**1,116,855**	**0**	**1,195,859**	**0**

- *Account 1925 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amount is calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. Thus, the 2006 Board approved amount does not reflect amortization of more than 2 years of investment made by NOTL Hydro in a new integrated customer information, billing and financial system, through to the 2006 actual.

Accumulated Depreciation - Equipment

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Equipment									
1915-Office Furniture and Equipment	118,027	127,736	0	132,881	0	138,576	0	144,687	0
1930-Transportation Equipment	762,075	802,265	0	594,095	(208,169)	677,627	0	763,987	0
1935-Stores Equipment	12,716	14,055	0	14,316	0	14,600	0	15,984	0
1940-Tools, Shop and Garage Equipment	184,501	236,589	0	263,700	0	292,274	0	320,465	0
1945-Measurement and Testing Equipment		0	0	0	0	0	0	0	0
1950-Power Operated Equipment		0	0	0	0	0	0	0	0
1955-Communication Equipment	8,477	17,675	0	19,944	0	22,212	0	24,481	0
1960-Miscellaneous Equipment		0	0	0	0	0	0	0	0
Sub-Total-Equipment	**1,085,796**	**1,198,319**	**0**	**1,024,936**	**(208,169)**	**1,145,290**	**0**	**1,269,605**	**0**

- *Account 1930 – 2007 Actual vs. 2006 Actual*

The variance results from the amortization expense for the transportation equipment account net of the write-off in 2007 of two fully depreciated trucks in the 3 tons and over category.

Accumulated Depreciation - Other Distribution Assets – Contributions and Grants

Description	2006 Board Approved ($)	2006 Actual ($)	Material Variance from 2006 Board Approved	2007 Actual ($)	Material Variance from 2006 Actual	2008 Bridge ($)	Material Variance from 2007 Actual	2009 Test ($)	Material Variance from 2008 Bridge
Other Distribution Assets									
1825-Storage Battery Equipment		0	0	0	0	0	0	0	0
1970-Load Management Controls - Customer Premises		0	0	0	0	0	0	0	0
1975-Load Management Controls - Utility Premises		0	0	0	0	0	0	0	0
1980-System Supervisory Equipment	59,305	99,333	0	119,940	0	141,304	0	163,335	0
1985-Sentinel Lighting Rental Units		0	0	0	0	0	0	0	0
1990-Other Tangible Property			0		0		0		0
1995-Contributions and Grants - Credit	(321,126)	(671,135)	(350,009)	(858,710)	0	(1,054,910)	(196,200)	(1,256,364)	(201,454)
1996-Hydro One S/S Contribution		0	0	0	0	0	0	0	0
Sub-Total-Other Distribution Assets	**(261,821)**	**(571,801)**	**(350,009)**	**(738,769)**	**0**	**(913,606)**	**(196,200)**	**(1,093,029)**	**(201,454)**

- *Account 1995 – 2006 Actual vs. 2006 Approved*

The 2006 Board approved amount is calculated as the average of the 2003 and 2004 actual amounts in accordance with the OEB 2006 rate model. As such, over two years normal depreciation through to the 2006 actual amount is not reflected in the 2006 Board approved amount.

- *Account 1995 – 2008 Bridge vs. 2007 Actual*

The variance in 2008 results from the amortization expense for the contribution and grants asset account in 2008.

FIVE-YEAR CAPITAL PLAN AND CAPITAL BUDGET by Project:

Five-Year Capital Plan

NOTL Hydro prepares an annual capital expenditure plan based on good utility practices and in conjunction with the guidelines established in our asset management policy and five-year capital plan. The asset management policy is provided in **Exhibit 2, Tab 3, Schedule 5**.

A rolling five-year capital plan is approved annually by the NOTL Hydro Board of Directors. The plan is largely delivered as approved but can vary slightly, with NOTL Hydro Board approval, due to unforeseen circumstances, such as a major relocation/rebuild prompted by a Road Authority. The most recent five-year capital plan for the years 2008 to 2012 is provided in Table 1 below:

Table 1
Five-Year Capital Plan

CAPITAL 5-YEAR PLAN	2008 Bridge Year	2009 Test Year	2010	2011	2012
Overhead Projects					
Queenston Village restoration	$ 30,000	$ -	$ -	$ -	$ -
Concession 5-reconductor 14 poles	$ 50,000	$ -	$ -	$ -	$ -
York Road Conversion	$ 90,000	$ 10,000	$ -	$ -	$ -
Queenston Road Conversion	$ 190,500	$ 175,000	$ 70,000	$ -	$ -
Conc. 7 Fdr ext. to Lakeshore	$ -	$ 160,000	$ 175,000	$ 175,000	$ -
4kV/27.6kV Conversion Program	$ -	$ -	$ 100,000	$ 170,000	$ 195,000
Pole Replacement/Cond upgrade	$ -	$ -	$ -	$ -	$ 150,000
Supervision	$ 60,000	$ 64,998	$ 65,000	$ 65,000	$ 65,000
New Connections	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
Miscellaneous	$ 6,050	$ 12,500	$ 20,000	$ 20,000	$ 20,000
Sub-Total	**$ 451,550**	**$ 447,498**	**$ 455,000**	**$ 455,000**	**$ 455,000**
Underground Projects					
Chautauqua U/G Project	$ 300,000	$ 1,000,000	$ 200,000	$ -	$ -
27.6kV U/G Projects	$ -	$ -	$ -	$ 160,000	$ 230,000
New Connections	$ 110,000	$ 110,000	$ 110,000	$ 110,000	$ 110,000
Miscellaneous Projects	$ 26,450	$ 20,000	$ 18,000	$ 18,000	$ 18,000
Supervision	$ 60,000	$ 64,998	$ 65,000	$ 65,000	$ 65,000
Sub-Total	**$ 496,450**	**$ 1,194,998**	**$ 393,000**	**$ 353,000**	**$ 423,000**
Stations					
NOTL MTS2	$ 130,000	$ 5,000	$ 5,000	$ -	$ -
YorkMTS1	$ -	$ -	$ 210,000	$ -	$ 225,000
Virgil clean-up	$ -	$ 40,000	$ -	$ -	$ -
Homer Clean-up					
Sub-Total	**$ 130,000**	**$ 45,000**	**$ 215,000**	**$ -**	**$ 225,000**
Subdivisions					
Yearly Costs	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Sub-Total	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ 50,000**
Office Equipment					
Nominal	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Sub-Total	**$ 5,000**	**$ 5,000**	**$ 5,000**	**$ 5,000**	**$ 5,000**
Computer Hardware					
Desk top Units/associated parts	$ 15,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Sub-Total	**$ 15,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**	**$ 10,000**
Computer Software & Consulting					
Software upgrades/consulting	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Sub-Total	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ 50,000**
Stores Warehouse Equipment					
Miscellaneous	$ 2,000	$ 20,000	$ 2,000	$ 2,000	$ 2,000
Sub-Total	**$ 2,000**	**$ 20,000**	**$ 2,000**	**$ 2,000**	**$ 2,000**
Rolling Stock					
Vehicle Replacement	$ 30,000	$ -	$ 30,000	$ 250,000	$ -
Sub-Total	**$ 30,000**	**$ -**	**$ 30,000**	**$ 250,000**	**$ -**
Other					
New Meters	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
GIS & SCADA	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Tools	$ 5,000	$ 5,000	$ 15,000	$ 15,000	$ 15,000
Sub-Total	**$ 35,000**	**$ 35,000**	**$ 45,000**	**$ 45,000**	**$ 45,000**
Building H&S Upgrades					
Miscellaneous	$ 3,000	$ 20,000	$ 35,000	$ 5,000	$ 25,000
Repairs/upgrades to HVAC System	$ 22,000	$ -	$ -	$ -	$ -
Upgrade to front counter		$ -	$ -	$ -	$ -
Replace flat roof	$ -	$ -	$ -	$ 65,000	$ -
Sub-Total	**$ 25,000**	**$ 20,000**	**$ 35,000**	**$ 70,000**	**$ 25,000**
Contributed Capital Customer Projects					
NOTL Hydro	$ 150,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
Capital contributions	-$ 150,000	-$ 150,000	-$ 150,000	-$ 150,000	-$ 150,000
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Projects	**$ 1,290,000**	**$ 1,877,496**	**$ 1,290,000**	**$ 1,290,000**	**$ 1,290,000**

This five-year plan includes a major underground project known as “Chautauqua”. This $1.5 million project commenced in 2008 and will be completed over three years. NOTL Hydro originally considered completing this project equally over the three year period at $0.5 million per year within the normal annual capital budget level of approximately $1.3 million. Three primary reasons have prompted NOTL Hydro to ramp up construction of the project in 2009 to the level of $1 million, as shown in the five year plan. This ramp up results in a $600,000 addition to the normal annual capital budget level, bringing the 2009 total to approximately $1.9 million:

1. to ease the impact of excessive construction on local residents (the system is expected to be fully operational by the summer of 2009);

2. to gain financial savings that can reasonably be expected from having a single large construction contract versus two or three contracts; and

3. to take advantage of the Town of Niagara-on-the-Lake’s schedule to complete and restore Chautauqua roadways in late 2009. Construction in 2010 will primarily include connection of individual services to the new system.

A further rationale to exceed our normal annual capital project spending relates to the fact that it would be difficult to delay previously scheduled overhead projects to 2010. Our largely rural system previously acquired from Ontario Hydro is still in a critical rebuild schedule to ensure quality and reliable supply to our customers. As well, a majority of our regular overhead construction is conducted by our own forces. A major gap in this construction would require a year-long layoff of quality line personnel and would jeopardize the critical rebuild schedule.

Further details of the Chautauqua project are provided in the capital budget by project below for years 2008 and 2009.

Capital Budget by Project

The following is a summary of actual capital projects for the years 2006 and 2007 and planned capital projects for the 2008 bridge year and the 2009 test year. The plans for 2008 and 2009 reflect the five-year capital plan outlined above.

2006 Actual

The following Table 2 provides a breakdown of the actual 2006 capital projects by USoA with data consistent with the fixed asset continuity schedule in **Exhibit 2 Tab 2 Schedule 1** Table 1. Descriptions of the projects follow the table below:

Table 2

ACTUAL	2006 Total	1805	1815	1830	1835	1840	1845	1850	1855	1860	1908	1915	1920	1925	1930	1935	1940	1980	1995
Overhead Projects																			
York Road Conversion	$ 24,888				$ 7,719			$ 17,169											
Queenston Road Conversion	$ 104,371			$ 6,468	$ 70,334			$ 27,569											
Line 8 upgrade	$ 88,668			$ 40,641	$ 48,027														
Concession 2 conversion	$ 36,350			$ 1,071	$ 7,263			$ 28,016											
Supervision	$ 58,061			$ 19,363	$ 21,954			$ 16,744											
New Connections	$ 25,317								$ 25,317										
Miscellaneous	$ 96,000			$ 29,017	$ 6,914			$ 60,069											
Sub-Total	$ 433,655		**$ -**	**$ 96,560**	**$ 162,211**	**$ -**		**$ 149,567**	**$ 25,317**	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Underground Projects																			
Queenston Village Upgrade	$ 462,151					$ 180,337	$ 175,951	$ 105,863											
New Connections	$ 212,801								$ 212,801										
Miscellaneous Projects	$ 60,725					$ 36,365	$ 16,211	$ 8,149											
Supervision	$ 55,183					$ 15,898	$ 21,516	$ 17,769											
Sub-Total	$ 790,860		$ -	$ -	$ -	$ 232,600	$ 213,678	$ 131,781	$ 212,801	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Stations																			
Stations	$ 181,672	$ 2,200	$ 179,472																
Sub-Total	$ 181,672	$ 2,200	$ 179,472	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subdivisions																			
Yearly Costs	$ 527,234			$ 65,661	$ 45,168	$ 119,192	$ 191,953	$ 105,260											
Sub-Total	$ 527,234		$ -	$ 65,661	$ 45,168	$ 119,192	$ 191,953	$ 105,260	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Equipment																			
Office equipment	$ 9,406											$ 9,406							
Sub-Total	$ 9,406		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 9,406	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Hardware																			
Desk top Units/associated parts	$ 14,470												$ 14,470						
Sub-Total	$ 14,470		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ 14,470	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software & Consulting																			
Software upgrades/consulting	$ 94,316													$ 94,316					
Sub-Total	$ 94,316		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ 94,316	$ -	$ -	$ -	$ -	$ -
Stores Warehouse Equipment																			
None	$ -																		
Sub-Total	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rolling Stock																			
Vehicle disposal	-$ 25,691														-$ 25,691				
Vehicle Replacement	$ 24,883														$ 24,883				
Sub-Total	-$ 808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 808	$ -	$ -	$ -	$ -
Other																			
New Meters	$ 36,022									$ 36,022									
Transformer disposal	-$ 237,699							-$ 237,699											
Transfomer inventory/damage/spare	$ 238,917							$ 238,917											
Meter inventory	$ 17,803									$ 17,803									
Meter disposal	-$ 4,440									-$ 4,440									
GIS & SCADA	$ 19,675																	$ 19,675	
Tools	$ 6,580																$ 6,580		
Sub-Total	$ 76,858		$ -	$ -	$ -	$ -	$ -	$ 1,218	$ -	$ 49,385		$ -	$ -	$ -	$ -	$ -	$ 6,580	$ 19,675	$ -
Building H&S Upgrades																			
Miscellaneous	$ 8,420										$ 8,420								
Sub-Total	$ 8,420		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,420	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Customer Projects																			
NOTL Hydro	$ 379,850			$ 13,148	$ 15,897	$ 90,278	$ 109,808	$ 150,719											
Capital contributions	-$ 998,564																		-$ 998,564
Sub-Total	-$ 618,714		$ -	$ 13,148	$ 15,897	$ 90,278	$ 109,808	$ 150,719	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 998,564
Total Projects	**$ 1,517,368**	**$ 2,200**	**$ 179,472**	**$ 175,369**	**$ 223,276**	**$ 442,070**	**$ 515,439**	**$ 538,545**	**$ 238,118**	**$ 49,385**	**$ 8,420**	**$ 9,406**	**$ 14,470**	**$ 94,316**	**-$ 808**	**$ -**	**$ 6,580**	**$ 19,675**	**-$ 998,564**
FA Continuity Schedule	*$ 1,517,368*	*$ 2,200*	*$ 179,472*	*$ 175,369*	*$ 223,276*	*$ 442,070*	*$ 515,439*	*$ 538,545*	*$ 238,118*	*$ 49,385*	*$ 8,420*	*$ 9,406*	*$ 14,470*	*$ 94,316*	*-$ 808*	*$ -*	*$ 6,580*	*$ 19,675*	*-$ 998,564*

Exhibit 2 Tab 2 Schedule 1 Table 4 *Some numbers may not appear to add due to rounding*

<u>Distribution Stations</u>

In 2005 Niagara-on-the-Lake Hydro purchased NOTL MTS2 from Hydro One. The Station was constructed in 1985 and has been in continuous service since that time. Although maintenance records indicate proper and prudent maintenance activities by the previous owners since construction, no equipment upgrades had been completed. Niagara-on-the-Lake Hydro reviewed the condition of the Station and determined equipment upgrades were required to modernize and ensure continued power supply reliability to its customers.

The upgrade project is to include the installation of two 115kV S&C Switchgear devices for Transformer 1 and Transformer 2, and associated 115kV bus and structure modifications. Included in this project is the installation of Schweitzer relays on F1, F2 & F4 breakers, updated SCADA communication link with the IESO and our Control Room function provided by Waterloo North Hydro, all associated civil work, and power and communication cable installations. Control building upgrades for this project include, external secondary power supply and transfer capability, a new racking system to house relays and SCADA equipment integral to the Breaker relay and S&C Switchgear control and communication function.

The work on this project in 2006 includes; design and engineering services, civil work required for new communication and power cables, purchase of 1-115kV S&C switchgear.

Gross cost - $181,672 = $2,200 in USoA 1805 + $179,472 in 1815

<u>Distribution Overhead</u>

Queenston Road Upgrade: System enhancement which includes voltage conversion and reinforcement for improved system inter-tie capability. As part of Niagara-on-the-Lake Hydro’s General Plan to offload the 4kV System and Improve Operating Efficiency this project will improve overall line losses through both voltage conversion and the replacement of the existing conductor. The conductor replacement has a twofold benefit in this project as it allows greater system operational flexibility when completed by creating a tie point between York MTS1 and NOTL MTS2.

The work on this section of the project includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, conductor ampacity upgrade as this section of line can be used as a feeder tie between York MTS1 and NOTL MTS2, secondary bus replacement, and new transformers. Work on this section of Line is on Queenston Road between Coon Road and Townline Road and at Queenston Road and York Road intersection.

Gross cost - $104,371 = $6,468 in USoA 1830 + $70,334 in 1835 + $27,569 in 1850

Line 8 Upgrade: System enhancement which includes voltage conversion and improvement. As part of Niagara-on-the-Lake Hydro's General Plan to Offload the 4kV System this project will improve overall line losses through both voltage conversion and by replacing the existing #2 copper conductor with 1/0 ACSR conductor. Area identified through annual inspection as are in need of improvement due to age and condition of the pole line. In addition this project coincided with Niagara-on-the-Lake's plan to decommission existing St-David's 4kV Sub- Station feeding the area.

The work on this project includes; pole replacement due to height requirements and age, new 1/0 primary conductor, new 1/0 neutral conductor, secondary bus replacement, and new transformers. This project assisted in the reduction of line losses on our system by upgrading the operating voltage from 4kV to 16kV, and also assisted with Niagara-on-the-Lake's long term system objective to offload the 4kV system.

Gross cost - $88,668 = $40,641 in USoA 1830 + $48,027 in 1835

Concession 2 Conversion: System enhancement project which includes voltage conversion and improved operating efficiency through reduction in line losses. As part of Niagara-on-the-Lake Hydro's General Plan to offload the 4kV System this project will improve line losses through voltage conversion from 4kV to 27.6kV. This project coincided with Niagara-on-the-Lake's plan to decommission the existing St-David's 4kV Sub- Station feeding the area.

The work on this project involved the removal of a three-phase 4kV circuit on a double circuit pole line, the second circuit being 27.6kV, and new transformers.

Gross cost - $36,350 = $1,071 in USoA 1830 +$7,263 in 1835 + $28,016 in 1850

York Road Upgrade: System enhancement project which includes voltage conversion, system reliability, and improved operating efficiency through reduction in line losses. As part of Niagara-on-the-Lake Hydro's General Plan to offload the 4kV System this project will improve line losses through voltage conversion from 4kV to 27.6kV, improved customer power supply reliability by providing a second feed option from York MTS1 M1 feeder into Queenston Village and the Queenston/Lewiston International Bridge complex.

Completed in 2006 is the design of phase one and the purchase of transformers and select hardware required for the project commencement in 2007.

Gross cost - $24,888 = $7,719 in USoA 1835 + $17,169 in 1850

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Gross cost - $96,000 = $29,017 in USoA 1830 + $6,914 in 1835 + $60,069 in 1850

New Connections: Niagara-on-the-lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Gross cost - $25,137 = $25,137 in USoA 1855

Supervision of Overhead Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Gross cost - $58,061 = $19,363 in USoA 1830 + $21,954 in 1835 + $16,744 in 1850

Distribution Underground

New Connections: Niagara-on-the-lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Gross cost - $212,801 = $212,801 in USoA 1855

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Gross cost - $60,725 = $36,365 in USoA 1840 + $16,211 in 1845 + $8,149 in 1850

Village of Queenston Upgrade Project: System enhancement project which includes voltage conversion and area improvement. System study demonstrated the age of the infrastructure in the Village of Queenston had exceeded its expected life and required replacement. The Municipality of Niagara-on-the-Lake requires through by-law that areas designated by the community as historic and tourist focused are to have all services buried when any new construction is undertaken. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system, and due to the Town by-law to bury all new servicing, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system in the Village of Queenston. This decision has the added benefit of reducing load on the 4kV St-David's Station which is scheduled to be decommissioned in 2008.

The work on this project include the installation of all duct work, primary and secondary conductor, transformers and associated hardware, customer electrical service conversion from overhead to underground, and the decommissioning and removal of all overhead poles and hardware.

Gross cost - $462,151 = $180,337 in USoA 1840 + $175,951 in 1845 + $105,863 in 1850

Supervision of Underground Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Gross cost - $55,183 = $15,898 in USoA 1840 + $21,516 in 1845 + $17,769 in 1850

Subdivisions

Niagara-on-the-Lake Hydro service area continued to see modest growth of approximately 1% for 2006 with number of new subdivision starts continuing a four year trend.

Gross cost - $527,234 = $65,661 in USoA 1830 + $45,168 in 1835 + $119,192 in 1840 + $191,953 in 1845 + $105,260 in 1850

Capital Customer Projects

NOTL Hydro

System expansion and enhancements required to service customer demand for new residential and commercial developments, and municipal and regional road works.

Gross cost - $379,850 = $13,148 in USoA 1830 + $15,897 in 1835 + $90,278 in 1840 + $109,808 in 1845 + $150,179 in 1850

Capital Contributions

Contributed capital continues to be received from new residential developments, subdivisions, new general service connections, and municipal and regional road works.

Gross cost – ($998,564) = $-998,564 in USoA 1995

Distribution Meters

The costs associated with the purchase and installation of new revenue meters and equipment to meet new customer and commercial growth and the replacement of retired distribution meters.

Gross cost - $36,022 = $36,022 in USoA 1860

Changes in meter inventory level:

Gross cost - $17,803 = $17,803 in USoA 1860

Disposal of meters:

Gross cost – ($4,440) = $-4,440 in USoA 1860

Transformers

Disposal of transformers:

Gross cost – ($237,699) = $-237,699 in USoA 1850

A change in overall transformer inventory and an increase in damaged and repaired transformers due to failures related to inclement weather and other damages.

Gross cost – $238,917 = $238,917 in USoA 1850

Office Equipment

Costs associated with the upgrade of peripheral office equipment and for the ergonomic improvements to workstations.

Gross cost - $9,406 = $9,406 in USoA 1915

<u>Computer Hardware</u>

Scheduled replacement/upgrade of workstation desktop units and associated equipment as part of the Asset Management Lifecycle of three to four years of active service.

Gross cost - $14,470 = $14,470 in USoA 1920

<u>Computer Software</u>

Costs associated with software upgrades and Information Technology consulting to ensure system reliability and compliance with Ontario Energy Board mandated requirements.

Gross cost - $94,316 = $94,316 in USoA 1925

<u>Stores Warehouse Equipment</u>

There were no purchases made for this line item in 2006.

<u>Rolling Stock</u>

Niagara-on-the-Lake Hydro has a scheduled replacement plan for all vehicles in our fleet as per our Asset Management Policy. A six to seven year interval for pickups and vans is common while large operations vehicles can exceed 15 years. Final decisions are dependant on the condition and mileage of the vehicle. Although no vehicle was scheduled for replacement in 2006, a pick-up truck in the fleet was destroyed due to a motor vehicle accident. This vehicle was replaced with a previously used crew cab style pick-up truck for multi purpose use.

Purchase of the used pick-up truck:

Gross cost - $24,883 = $24,883 in USoA 1930

Write-off of the destroyed pick-up truck:

Gross cost – ($25,691) = $-25,691 in USoA 1930

Miscellaneous Equipment and Major Tools

This section covers Major Tools and Equipment for the Line Services and Engineering sections of Niagara-on-the-Lake Hydro.

Allocation for G.I.S. and SCADA upgrades, testing, commissioning and consultant costs required for the continuous improvement of our electrical system information storage and tracking capability.

Tool purchases for Line Services to increase efficiencies and ergonomic benefit.

Gross cost - $26,255 = $19,675 in USoA 1980 + $6,580 in 1940

Buildings and Fixtures

Purchase of a portion of the equipment required to install a new fire alarm and emergency exit lighting system to update the #8 Henegan Road facilities. Purchase of the remaining portion of the equipment and the installation of the systems to be completed in 2007.

Gross cost - $8,420 = $8,420 in USoA 1908

2007 Actual

The following Table 3 provides a breakdown of the actual 2007 capital projects by USoA with data consistent with the fixed asset continuity schedule in **Exhibit 2 Tab 2 Schedule 1** Table 2. Descriptions of the projects follow the table below:

Table 3

ACTUAL	2007 Total	1805	1815	1830	1835	1840	1845	1850	1855	1860	1908	1915	1920	1925	1930	1935	1940	1980	1995
Overhead Projects																			
York Road Conversion	$ 135,739			$ 32,041	$ 94,427	$ 41		$ 9,230											
Queenston Road Conversion	$ 41,094				$ 36,217			$ 4,877											
Highway 55 to Stewart Rd	$ 48,587				$ 48,587														
Supervision	$ 48,041			$ 15,394	$ 18,880			$ 13,767											
New Connections	$ 26,727								$ 26,727										
Miscellaneous	$ 30,342			$ 10,570	$ 9,323			$ 10,449											
Sub-Total	**$ 330,530**	**$ -**	**$ -**	**$ 58,005**	**$ 207,434**	**$ 41**		**$ 38,323**	**$ 26,727**	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Underground Projects																			
Queenston Village Upgrade	$ 34,602					-$ 1,658	$ 3,522	$ 32,738											
Chautauqua	$ 1,106					$ 529	$ 219	$ 358											
New Connections	$ 216,845								$ 216,845										
Miscellaneous Projects	$ 29,857					$ 9,033	$ 2,849	$ 17,975											
Supervision	$ 62,933					$ 10,543	$ 16,711	$ 35,679											
Sub-Total	$ 345,343	$ -	$ -	$ -	$ -	$ 18,447	$ 23,301	$ 86,750	$ 216,845	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Stations																			
Stations	$ 185,732		$ 185,536					$ 196											
Sub-Total	$ 185,732	$ -	$ 185,536	$ -	$ -	$ -	$ -	$ 196	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subdivisions																			
Yearly Costs	$ 209,938					$ 65,239	$ 79,245	$ 65,454											
Sub-Total	$ 209,938	$ -	$ -	$ -	$ -	$ 65,239	$ 79,245	$ 65,454	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Equipment																			
Office equipment	$ 5,984											$ 5,984							
Sub-Total	$ 5,984	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 5,984	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Hardware																			
Desk top Units/associated parts	$ 21,275												$ 21,275						
Sub-Total	$ 21,275	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ 21,275	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software & Consulting																			
Software upgrades/consulting	$ 66,892													$ 66,892					
Sub-Total	$ 66,892	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ 66,892	$ -	$ -	$ -	$ -	$ -
Stores Warehouse Equipment																			
Racking	$ 1,804															$ 1,804			
Sub-Total	$ 1,804	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ 1,804	$ -	$ -	$ -
Rolling Stock																			
Vehicle disposal	-$ 273,051														-$ 273,051				
Vehicle Replacement	$ 250,400														$ 250,400				
Sub-Total	-$ 22,651	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 22,651	$ -	$ -	$ -	$ -
Other																			
New Meters	$ 2,879									$ 2,879									
Transformer disposal	-$ 21,271							-$ 21,271											
Transfomer inventory/damage/spare	$ 15,373							$ 15,373											
Meter inventory	$ 22,246									$ 22,246									
Meter disposal	-$ 18,557									-$ 18,557									
GIS & SCADA	$ 12,721																	$ 12,721	
Tools	$ 34,202																$ 34,202		
Sub-Total	$ 47,593	$ -	$ -	$ -	$ -	$ -	$ -	-$ 5,898	$ -	$ 6,568		$ -	$ -	$ -	$ -	$ -	$ 34,202	$ 12,721	$ -
Building H&S Upgrades																			
Miscellaneous	$ 42,450										$ 42,450								
Sub-Total	$ 42,450	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,450	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Customer Projects																			
NOTL Hydro	$ 123,890			$ 4,412	$ 3,949	$ 6,790	$ 15,153	$ 93,586											
Capital contributions	-$ 304,697																		-$ 304,697
Sub-Total	-$ 180,807	$ -	$ -	$ 4,412	$ 3,949	$ 6,790	$ 15,153	$ 93,586	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 304,697
Total Projects	**$ 1,054,083**	**$ -**	**$ 185,536**	**$ 62,417**	**$ 211,383**	**$ 90,517**	**$ 117,699**	**$ 278,411**	**$ 243,572**	**$ 6,568**	**$ 42,450**	**$ 5,984**	**$ 21,275**	**$ 66,892**	**-$ 22,651**	**$ 1,804**	**$ 34,202**	**$ 12,721**	**-$ 304,697**
FA Continuity Schedule	*$ 1,054,083*	*$ -*	*$ 185,536*	*$ 62,417*	*$ 211,383*	*$ 90,517*	*$ 117,699*	*$ 278,411*	*$ 243,572*	*$ 6,568*	*$ 42,450*	*$ 5,984*	*$ 21,275*	*$ 66,892*	*-$ 22,651*	*$ 1,804*	*$ 34,202*	*$ 12,721*	*-$ 304,697*
Exhibit 2 Tab 2 Schedule 1 Table 4																			

Distribution Stations

Continuation of NOTL MTS2 upgrade project for 2007 includes the installation of an 115kV S&C Switchgear unit and associated bus and structure modifications to the T2 transformer bank. Included in this project year was the installation of Schweitzer relays on F1, F2 & F4 breakers, SCADA communication link with the IESO, and our Control Room function provided by Waterloo North Hydro, all associated civil work, power and communication cable installations. Control building upgrades for this project include, external secondary power supply and transfer capability, a new racking system to house relays and SCADA equipment integral to the Breaker relay and S&C Switchgear control and communication.

Gross cost - $185,732 = $185,536 in USoA 1815 + $196 in 1850

Distribution Overhead

Queenston Road Upgrade: Continuation of system enhancement project which includes voltage conversion and reinforcement for improved system inter-tie capability.

The work on this section of the project includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, conductor ampacity upgrade as this section of line can be used as a feeder tie between York MTS1 and NOTL MTS2, secondary bus replacement, and new transformers.

Gross cost - $41,094 = $36,217 in USoA 1835 +$4,877 in 1850

York Road Upgrade: System enhancement project which includes voltage conversion, system reliability, and improved operating efficiency through reduction in line losses. 2007 is phase one of a three phase project. The conversion and upgrade begins at the NE corner Concession 2 and York Road and continues to Sheppard Road for the 1st phase.

The work on this line includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, secondary bus replacement, and new transformers. The completion of this project allows a second feed option from York MTS1 M1 feeder into Queenston Village and the Queenston/Lewiston International Bridge complex.

Gross cost - $135,739 = $32,041 in USoA 1830 + $94,427 in 1835 + $41 in 1840 + $9,230 in 1850

Hwy. 55 to Stewart Road: System enhancement and reinforcement project to replace existing conductor with that of a greater load rating to improve operating efficiency. This section of YORK MTS2 M2 feeder had 3/0 conductor which limited the ampacity of the remaining circuit conductor of 556MCM. The upgrade now allows greater operational flexibility and an improved system line loss ratio.

The work on this section of line includes; replacement of 1092m of 3/0 ACSR conductor with 556MCM AL.

Gross cost - $48,587 = $48,587 in USoA 1835

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Gross cost - $30,342 = $10,570 in USoA 1830 + $9,323 in 1835 + $10,449 in 1850

New Connections: Niagara-on-the-lake Hydro’s service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Gross cost - $26,727 = $26,727 in USoA 1855

Supervision of Overhead Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Gross cost - $48,041 = $15,394 in USoA 1830 + $18,880 in 1835 + $13,767 in 1850

<u>Distribution Underground</u>

New Connections: Niagara-on-the-lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Gross cost - $216,845 = $216,845 in USoA 1855

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Gross cost - $29,857 = $9,033 in USoA 1840 + $2,849 in 1845 + $17,975 in 1850

Chautauqua Project: System enhancement project which includes voltage conversion and area improvement. System study demonstrated the average age of the electrical plant in this Old Town urban area is approaching 50 years and annual plant inspections have indicated that a majority of the area is reaching the end of its useful life. The Town of Niagara-on-the-Lake has also committed to install new sewer and water lines in 2008/2009 and will commence construction in advance of our project. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system and given the location within the urban boundaries of the Old Town, local by-laws require that we bury our new facilities, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system.

The work conducted in 2007 includes; preliminary design work and stakeholder meetings to discuss the 4kV overhead to 27.6kV underground upgrade and conversion Project with stakeholders.

Gross cost - $1,106 = $529 in USoA 1840 + $219 in 1845 + $358 in 1850

Village of Queenston Upgrade Project: System enhancement project which includes voltage conversion and area improvement. System study demonstrated the age of the infrastructure in the Village of Queenston had exceeded its expected life and required replacement. The Municipality of Niagara-on-the-Lake requires areas designated by the community as historic and tourist focused to have all services buried when any new construction is undertaken. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system, and due to the Town by-law to bury all new servicing, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system in the Village of Queenston. This decision has the added benefit of reducing load on the 4kV St-David's Station which is scheduled to be decommissioned in 2008.

The work conducted in 2007 consisted of completing customer electrical services conversion from overhead to underground and decommissioning of the 4kV overhead system.

Gross cost - $34,602 = $-1,658 in USoA 1840 + $3,522 in 1845 + $32,738 in 1850

Supervision of Underground Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Gross cost - $62,933 = $10,543 in USoA 1840 + $16,711 in 1845 + $35,679 in 1850

<u>Subdivisions</u>

Niagara-on-the-Lake Hydro service area continued to see modest growth of approximately 1% for 2007 with number of new subdivision starts continuing a four year trend.

Gross cost - $209,938 = $65,239 in USoA 1840 + $79,245 in 1845 + $64,454 in 1850

<u>Capital Customer Projects</u>

NOTL Hydro

System expansion and enhancements required to service customer demand for new residential and commercial developments, and municipal and regional road works.

Gross cost - $123,890 = $4,412 in 1830 + $3,949 in 1835 + $6,790 in 1840 + $15,153 in 1845 + $93,586 in 1850

Capital Contributions

Contributed capital continues to be received from new residential developments, subdivisions, new general service connections, and municipal and regional road works.

Gross cost – ($304,697) = $-304,697 in USoA 1995

<u>Distribution Meters</u>

The costs associated with the purchase and installation of new revenue meters and equipment to meet new customer and commercial growth and the replacement of retired distribution meters.

Gross cost - $2,879 = $2,879 in USoA 1860

Changes in meter inventory level:

Gross cost - $22,246 = $22,246 in USoA 1860

Disposal of meters:

Gross cost – ($18,557) = $-18,557 in USoA 1860

<u>Transformers</u>

Disposal of transformers:

Gross cost – ($21,271) = $-21,271 in USoA 1850

A change in overall transformer inventory and an increase in damaged and repaired transformers due to failures related to inclement weather and other damages.

Gross cost – $15,373 = $15,373 in USoA 1850

Office Equipment

Costs associated with the upgrade of peripheral office equipment and for the ergonomic improvements to workstations.

Purchases for the year 2007 included new Boardroom furniture and hands-free telephone headsets for the Customer Service Representatives.

Gross cost - $5,984 = $5,984 in USoA 1915

Computer Hardware

Scheduled replacement/upgrade of workstation desktop units and associated equipment as part of the Asset Management Lifecycle of three to four years of active service.

Gross cost - $21,275 = $21,275 in USoA 1920

Computer Software

Costs associated with software upgrades and Information Technology consulting to ensure system reliability and compliance with Ontario Energy Board mandated requirements.

Gross cost - $66,892 = $66,892 in USoA 1925

Stores Warehouse Equipment

Purchases for the year 2007 and installation of new racking system in the warehouse to improve storage capacity and weight bearing capability.

Gross cost - $1,804 = $1,804 in USoA 1935

Rolling Stock

Niagara-on-the-Lake Hydro has a scheduled replacement plan for all vehicles in our fleet as per our Asset Management Policy. In 2007 a new Line Services aerial truck was added to our fleet to replace two existing Line aerial trucks. It replaces the need for two vehicles in the fleet; one vehicle used exclusively for daily customer service work and 4kV primary work and a second vehicle used exclusively for 27.6kV construction work. Two vehicles were used due to the fact the customer service truck was not properly insulated to be used on 27.6kV primary.

Purchase of the new line aerial truck:

Gross cost - $250,400 = $250,400 in USoA 1930

Disposal of the two existing line aerial trucks:

Gross cost – ($273,051) = $-273,051 in USoA 1930

Miscellaneous Equipment and Major Tools

This section covers Major Tools and Equipment for the Line Services and Engineering sections of Niagara-on-the-Lake Hydro.

Allocation for G.I.S. and SCADA upgrades, testing, commissioning and consultant costs required for the continuous improvement of our electrical system information storage and tracking capability.

Gross cost - $46,923 = $34,202 in USoA 1940 + $12,721 in 1980

Buildings and Fixtures

Improvements made in 2007 include the installation of a new fire alarm system and exit lighting to bring the building in-line with town by-laws in regard to fire and emergency safety. New automatic doors at the entrance of the office building were installed to provide improved wheelchair and handicap access to the

Building. Upgrades were made to the HVAC system in the building to improve air flow, and proper temperature distribution throughout the office areas of the building.

Gross cost - $42,450 = $42,250 in USoA 1908

2008 Bridge

The following Table 4 provides a breakdown of the 2008 bridge year capital projects from the 5 year capital plan by USoA with data consistent with the fixed asset continuity schedule in **Exhibit 2 Tab 2 Schedule 1** Table 3. Descriptions of the projects follow the table below:

Table 4

CAPITAL 5-YEAR PLAN	2008 Total	1815	1830	1835	1840	1845	1850	1855	1860	1908	1915	1920	1925	1930	1935	1940	1980	1995
Overhead Projects																		
Queenston Village restoration	$ 30,000		$ 5,000	$ 20,000			$ 5,000											
Concession 5-reconductor 14 poles	$ 50,000		$ 10,000	$ 40,000														
York Road Conversion	$ 90,000		$ 10,000	$ 70,000			$ 10,000											
Queenston Road Conversion	$ 190,500		$ 25,712	$ 111,630			$ 53,158											
Conc. 7 Fdr ext. to Lakeshore	$ -																	
4kV/27.6kV Conversion Program	$ -																	
Pole Replacement/Cond upgrade	$ -																	
Supervision	$ 60,000		$ 20,000	$ 20,000			$ 20,000											
New Connections	$ 25,000		$ 5,000	$ 20,000														
Miscellaneous	$ 6,050			$ 6,050														
Sub-Total	$ 451,550	**$ -**	**$ 75,712**	**$ 287,680**	**$ -**		**$ 88,158**	**$ -**	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Underground Projects																		
Chautauqua U/G Project	$ 300,000				$ 135,000	$ 135,000	$ 30,000											
27.6kV U/G Projects	$ -																	
New Connections	$ 110,000				$ 55,000	$ 55,000												
Miscellaneous Projects	$ 26,450				$ 5,000	$ 16,450	$ 5,000											
Supervision	$ 60,000				$ 20,000	$ 20,000	$ 20,000											
Sub-Total	$ 496,450	$ -	$ -	$ -	$ 215,000	$ 226,450	$ 55,000	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Stations																		
NOTL MTS2	$ 130,000	$ 130,000																
YorkMTS1	$ -																	
Virgil clean-up	$ -																	
Sub-Total	$ 130,000	$ 130,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subdivisions																		
Yearly Costs	$ 50,000							$ 50,000										
Sub-Total	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,000	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Equipment																		
Nominal	$ 5,000										$ 5,000							
Sub-Total	$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Hardware																		
Desk top Units/associated parts	$ 15,000											$ 15,000						
Sub-Total	$ 15,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ 15,000	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software & Consulting																		
Software upgrades/consulting	$ 50,000												$ 50,000					
Sub-Total	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ -
Stores Warehouse Equipment																		
Miscellaneous	$ 2,000														$ 2,000			
Sub-Total	$ 2,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ 2,000	$ -	$ -	$ -
Rolling Stock																		
Vehicle Replacement	$ 30,000													$ 30,000				
Sub-Total	$ 30,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 30,000	$ -	$ -	$ -	$ -
Other																		
New Meters	$ 20,000								$ 20,000									
GIS & SCADA	$ 10,000																$ 10,000	
Tools	$ 5,000															$ 5,000		
Sub-Total	$ 35,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,000		$ -	$ -	$ -	$ -	$ -	$ 5,000	$ 10,000	$ -
Building H&S Upgrades																		
Miscellaneous	$ 3,000									$ 3,000								
Repairs/upgrades to HVAC System	$ 22,000									$ 22,000								
Upgrade to front counter																		
Replace flat roof	$ -																	
Sub-Total	$ 25,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributed Capital Customer Projects																		
NOTL Hydro	$ 150,000		$ 25,000	$ 25,000	$ 25,000	$ 25,000		$ 50,000										
Capital contributions	-$ 150,000																	-$ 150,000
Sub-Total	$ -	$ -	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 150,000
Total Projects	**$ 1,290,000**	**$ 130,000**	**$ 100,712**	**$ 312,680**	**$ 240,000**	**$ 251,450**	**$ 143,158**	**$ 100,000**	**$ 20,000**	**$ 25,000**	**$ 5,000**	**$ 15,000**	**$ 50,000**	**$ 30,000**	**$ 2,000**	**$ 5,000**	**$ 10,000**	**-$ 150,000**
FA Continuity Schedule Exhibit 2 Tab 2 Schedule 1 Table 3	*$ 1,290,000*	*$ 130,000*	*$ 100,712*	*$ 312,680*	*$ 240,000*	*$ 251,450*	*$ 143,158*	*$ 100,000*	*$ 20,000*	*$ 25,000*	*$ 5,000*	*$ 15,000*	*$ 50,000*	*$ 30,000*	*$ 2,000*	*$ 5,000*	*$ 10,000*	*-$ 150,000*

<u>Distribution Stations</u>

NOTL MTS2 upgrades for 2008 include the installation of the second 115kV S&C Switchgear unit and associated bus and structure modifications to the T1 transformer bank. This project concludes the upgrades project for NOTL MTS2 begun in 2006.

Budget amount - $130,000 = $130,000 in USoA 1815

<u>Distribution Overhead</u>

Queenston Road Upgrade: Continuation of system enhancement project which includes voltage conversion and reinforcement for improved system inter-tie capability.

The work on this section of line includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, conductor ampacity upgrade as this section of line can be used as a feeder tie between York MTS1 and NOTL MTS2, secondary bus replacement, and new transformers.

Budget - $190,500 = $25,712 in USoA 1830 + $111,630 in 1835 + $53,158 in 1850

York Road Upgrade: This project is in its 2nd phase in 2008 completing this section of York Road between Sheppard Road and the Niagara River Parkway.

The work on this section of line includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, secondary bus replacement, and new transformers. The completion of this project allows a second feed option from York MTS1 M1 feeder into Queenston Village and the Queenston/Lewiston International Bridge complex.

Budget - $90,000 = $10,000 in USoA 1830 + $70,000 in 1835 + $10,000 in 1850

Queenston Village Project: Completion of the system enhancement project which includes voltage conversion and area improvement.

The work conducted in 2008 consists of the removal of all poles and hardware.

Budget - $30,000 = $5,000 in USoA 1830 + $20,000 in 1835 + $5,000 in 1850

Concession 5 Upgrade: System enhancement and reinforcement project to replace existing conductor with that of a greater load rating to improve operating efficiency. This section of NOTL MTS2 egress feeder had 3/0 conductor which limited the ampacity of the remaining circuit conductor of 556MCM . The upgrade now allows greater operational flexibility by completing one section of system inter-tie between York MTS1 and NOTL MTS2, and an improved system line loss ratio.

Work on this project includes the replacement of 14 poles due to age and existing height limitations and the replacement of 770m of 3-phase 3/0 ACSR with 556MCM AL conductor.

Budget - $50,000 = $10,000 in USoA 1830 + $40,000 in 1835

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Budget - $6,050 = $6,050 in USoA 1835

New Connections: Niagara-on-the-lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range (see budget for Distribution Underground – New Connections).

Budget - $25,000 = $5,000 in USoA 1830 + $20,000 in 1835

Supervision of Overhead Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Budget - $60,000 = $20,000 in USoA 1830 + $20,000 in 1835 + $20,000 in 1850

Distribution Underground

New Connections: Niagara-on-the-lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Budget – $110,000 = $55,000 in USoA 1840 + $55,000 in 1845

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Budget - $26,450 = $5,000 in USoA 1840 + $16,450 in 1845 + $5,000 in 1850

Chautauqua Project: System enhancement project which includes voltage conversion and area improvement. System study demonstrated the average age of the electrical plant in this Old Town urban area is approaching 50 years and annual plant inspections have indicated that a majority of the area is reaching the end of its useful life. The Town of Niagara-on-the-Lake has also committed to install new sewer and water lines in 2008/2009 and will commence construction in advance of our project. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system and given the location within the urban boundaries of the Old Town, local by-laws require that we bury our new facilities, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system.

The work conducted in 2008 includes; completion of design work and ongoing stakeholder meetings to discuss the 4kV overhead to 27.6kV underground upgrade and conversion Project with stakeholders, tender and construction award process, material purchases, beginning of civil construction and installation of duct work.

Budget - $300,000 = $135,000 in USoA 1840 + $135,000 in 1845 + $30,000 in 1850

Supervision of Underground Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Budget - $60,000 = $20,000 in USoA 1840 + $20,000 in 1845 + $20,000 in 1850

Subdivisions

NOTL Hydro historically has been experiencing load growth over the past four years of just over 1% and expects this trend to continue in 2008.

Budget - $50,000 = $50,000 in USoA 1855

Contributed Capital Customer Projects

Contributed capital continues to be received from new residential developments, new general service connections, and municipal and regional road works.

Budget - $150,000 = $25,000 in USoA 1830 + $25,000 in 1835 + $25,000 in 1840 + $25,000 in 1845 + $50,000 in 1855

and Budget – ($150,000) = ($150,000) in USoA 1995

Distribution Meters

Funds required for the installation of interval meters on our largest customers. These meters fall outside the mandate of Smart Metering.

Budget - $20,000 = $20,000 in USoA 1860

Office Equipment

Costs associated with the upgrade of peripheral office equipment and for the ergonomic improvements to workstations.

Purchases considered for the year 2008 include improved racking system in the mail and server rooms.

Budget - $5,000 = $5,000 in USoA 1915

Computer Hardware

Scheduled replacement/upgrade of workstation desktop units and associated equipment as part of the Asset Management Lifecycle of three to four years of active service.

Budget - $15,000 = $15,000 in USoA 1920

Computer Software

Costs associated with software upgrades and Information Technology consulting to ensure system reliability and compliance with Ontario Energy Board mandated requirements.

Budget - $50,000 = $50,000 in USoA 1925

Stores Warehouse Equipment

Investigate the vendors for the purchase, installation, and commissioning of a bar code system to improve efficiencies in warehouse operation and inventory management.

Budget - $2,000 = $2,000 in USoA 1935

Rolling Stock

Niagara-on-the-Lake Hydro has a scheduled replacement plan for all vehicles in our fleet as per our Asset Management Policy. A Line Services support vehicle is scheduled for replacement in 2008. The new vehicle purchased will be assigned to the Engineering

Services Department with Engineering's existing support vehicle re-assigned to Line Services.

Budget - $30,000 = $30,000 in USoA 1930

<u>Miscellaneous Equipment and Major Tools</u>

This section covers Major Tools and Equipment for the Line Services and Engineering sections of Niagara-on-the-Lake Hydro.

Allocation for G.I.S. and SCADA upgrades, testing, commissioning and consultant costs required for the continuous improvement of our electrical system information storage and tracking capability.

Budget - $15,000 = $5,000 in USoA 1940 + $10,000 in 1980

<u>Buildings and Fixtures</u>

Improvements scheduled for 2008 is the repair of a section of flat roof over the vehicle bay and storage area.

Budget - $25,000 = $25,000 in USoA 1908

<u>2009 Test</u>

2009 Capital Budget Proposal for Rebasing

The following Table 5 provides a breakdown of the 2009 test year capital projects from the 5 year capital plan by USoA with data consistent with the fixed asset continuity schedule in **Exhibit 2 Tab 2 Schedule 1** Table 4. Descriptions of the projects follow the table below:

Table 5

CAPITAL 5-YEAR PLAN	2009 Total	1805	1815	1830	1835	1840	1845	1850	1855	1860	1908	1915	1920	1925	1930	1935	1940	1980	1995
Overhead Projects																			
Queenston Village restoration	$ -																		
Concession 5-reconductor 14 poles	$ -																		
York Road Conversion	$ 10,000				$ 10,000														
Queenston Road Conversion	$ 175,000			$ 30,000	$ 130,000			$ 15,000											
Conc. 7 Fdr ext. to Lakeshore	$ 160,000			$ 30,000	$ 115,000			$ 15,000											
4kV/27.6kV Conversion Program	$ -																		
Pole Replacement/Cond upgrade	$ -																		
Supervision	$ 64,998			$ 21,666	$ 21,666			$ 21,666											
New Connections	$ 25,000			$ 5,000	$ 20,000														
Miscellaneous	$ 12,500				$ 12,500														
Sub-Total	$ 447,498		**$ -**	**$ 86,666**	**$ 309,166**	**$ -**		**$ 51,666**	**$ -**	**$ -**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Underground Projects																			
Chautauqua U/G Project	$ 1,000,000					$ 600,000	$ 300,000	$ 100,000											
27.6kV U/G Projects	$ -																		
New Connections	$ 110,000					$ 55,000	$ 55,000												
Miscellaneous Projects	$ 20,000					$ 7,500	$ 5,000	$ 7,500											
Supervision	$ 64,998					$ 21,666	$ 21,666	$ 21,666											
Sub-Total	$ 1,194,998		$ -	$ -	$ -	$ 684,166	$ 381,666	$ 129,166	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Stations																			
NOTL MTS2	$ 5,000		$ 5,000																
YorkMTS1	$ -																		
Virgil clean-up	$ 40,000	$ 40,000																	
Sub-Total	$ 45,000	$ 40,000	$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subdivisions																			
Yearly Costs	$ 50,000								$ 50,000										
Sub-Total	$ 50,000		$ -	$ -	$ -	$ -	$ -	$ -	$ 50,000	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Office Equipment																			
Nominal	$ 5,000											$ 5,000							
Sub-Total	$ 5,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Hardware																			
Desk top Units/associated parts	$ 10,000												$ 10,000						
Sub-Total	$ 10,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ 10,000	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software & Consulting																			
Software upgrades/consulting	$ 50,000													$ 50,000					
Sub-Total	$ 50,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ -
Stores Warehouse Equipment																			
Miscellaneous	$ 20,000															$ 20,000			
Sub-Total	$ 20,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ 20,000	$ -	$ -	$ -
Rolling Stock																			
Vehicle Replacement	$ -																		
Sub-Total	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other																			
New Meters	$ 20,000									$ 20,000									
GIS & SCADA	$ 10,000																	$ 10,000	
Tools	$ 5,000																$ 5,000		
Sub-Total	$ 35,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,000		$ -	$ -	$ -	$ -	$ -	$ 5,000	$ 10,000	$ -
Building H&S Upgrades																			
Miscellaneous	$ 20,000										$ 20,000								
Repairs/upgrades to HVAC System	$ -																		
Upgrade to front counter	$ -																		
Replace flat roof	$ -																		
Sub-Total	$ 20,000		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Contributed Capital Customer Projects																			
NOTL Hydro	$ 150,000			$ 25,000	$ 25,000	$ 25,000	$ 25,000		$ 50,000										
Capital contributions	-$ 150,000																		-$ 150,000
Sub-Total	$ -		$ -	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ -	$ 50,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 150,000
Total Projects	**$ 1,877,496**	**$ 40,000**	**$ 5,000**	**$ 111,666**	**$ 334,166**	**$ 709,166**	**$ 406,666**	**$ 180,832**	**$ 100,000**	**$ 20,000**	**$ 20,000**	**$ 5,000**	**$ 10,000**	**$ 50,000**	**$ -**	**$ 20,000**	**$ 5,000**	**$ 10,000**	**-$ 150,000**
FA Continuity Schedule	*$ 1,877,496*	*$ 40,000*	*$ 5,000*	*$ 111,666*	*$ 334,166*	*$ 709,166*	*$ 406,666*	*$ 180,832*	*$ 100,000*	*$ 20,000*	*$ 20,000*	*$ 5,000*	*$ 10,000*	*$ 50,000*	*$ -*	*$ 20,000*	*$ 5,000*	*$ 10,000*	*-$ 150,000*
Exhibit 2 Tab 2 Schedule 1 Table 4																			

Distribution Stations

Niagara-on-the-Lake Hydro (NOTL Hydro) has completed the upgrades required at NOTL MTS2. Study will be undertaken to improve communication link between the Stations and the #8 Henegan Road office and decommission work at St-David's Station

Budget - $45,000 = $5,000 in USoA 1815 + $40,000 in 1805

Distribution Overhead

Queenston Road Upgrade: Continuation of system enhancement project which includes voltage conversion and reinforcement for improved system inter-tie capability.

The work on this section of line includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, conductor ampacity upgrade as this section of line can be used as a feeder tie between York MTS1 and NOTL MTS2, secondary bus replacement, and new transformers.

Budget - $175,000 = $30,000 in USoA 1830 + $130,000 in 1835 + $15,000 in 1850

York Road Upgrade: Completion of this Project entails the removal of all equipment.

Budget - $10,000 = $10,000 in USoA 1835

Concession 7 (F1) tie to East West Line (M2): System enhancement and expansion project. This Project will extend our F1 feeder from NOTL MTS2 to the North end of our system to support M2 feeder from York MTS1. During peak load conditions customers have experienced low voltage conditions at the end of M2 feeder and this tie will allow a direct route through our system from NOTL MTS2 F1 giving greater operational flexibility. Project costs have been allocated over a three-year period beginning in 2009 with Project completion scheduled for 2011.

Budget - $160,000 = $30,000 in USoA 1830 + $115,000 in 1835 + $15,000 in 1850

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Budget - $12,500 = $12,500 in USoA 1835

New Connections: Niagara-on-the-lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Budget - $25,000 = $5,000 in USoA 1830 + $20,000 in 1835

Supervision of Overhead Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Budget - $64,998 = $21,666 in USoA 1830 + $21,666 in 1835 + $21,666 in 1850

Distribution Underground

New Connections: Niagara-on-the-Lake Hydro's service area continues to see modest growth mainly in new residential and small commercial establishments, as in previous years the number of total new services was in the 100 range.

Budget – $110,000 = $55,000 in USoA 1840 + $55,000 in 1845

Miscellaneous Projects: Nominal amount to cover system improvements required due to findings from our annual inspections that are deemed to require immediate attention and are therefore not included in our current budget year for upgrade.

Budget - $20,000 = $7,500 in USoA 1840 + $5,000 in 1845 + $7,500 in 1850

Chautauqua Project: System enhancement project which includes voltage conversion and area improvement. System study demonstrated the average age of the electrical plant in this Old Town urban area is approaching 50 years and annual plant inspections have indicated that a majority of the area is reaching the end of its useful life. The Town of Niagara-on-the-Lake has also committed to install new sewer and water lines in 2008/2009 and will commence construction in advance of our project. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system and given the location within the urban boundaries of the Old Town, local by-laws require that we bury our new facilities, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system.

The work conducted in 2009 includes; completion of civil construction, installation of primary and secondary cable, placement of transformers, customer service connection conversions from overhead to underground, civil restoration work.

Budget - $1,000,000 = $600,000 in USoA 1840 +$300,000 in 1845 + $100,000 in 1850

Supervision of Underground Projects: Supervisory costs associated with the oversight of all capital overhead projects from initial design phase through to project completion.

Budget - $64,998 = $21,666 in USoA 1840 + $21,666 in 1845 + $21,666 in 1850

Subdivisions

NOTL Hydro historically has been experiencing load growth over the past four years of just over 1% and expects this trend to continue in 2009.

Budget - $50,000 = $50,000 in USoA 1855

Contributed Capital Customer Projects

Contributed capital continues to be received from new residential developments, new general service connections, and municipal and regional road works.

Budget - $150,000 = $25,000 in USoA 1830 + $25,000 in 1835 + $25,000 in 1840 + $25,000 in 1845 + $50,000 in 1855 and Budget – ($150,000) = ($150,000) in USoA 1995

<u>Distribution Meters</u>

Funds required for the installation of interval meters on our largest customers. These meters fall outside the mandate of Smart Metering.

Budget - $20,000 = $20,000 in USoA 1860

<u>Office Equipment</u>

Costs associated with the upgrade of peripheral office equipment and for the ergonomic improvements to workstations.

Purchases considered for the year 2008 include improved racking system in the mail and server rooms.

Budget - $5,000 = $5,000 in USoA 1915

<u>Computer Hardware</u>

Scheduled replacement/upgrade of workstation desktop units and associated equipment as part of the Asset Management Lifecycle of three to four years of active service.

Budget - $10,000 = $10,000 in USoA 1920

<u>Computer Software</u>

Costs associated with software upgrades and Information Technology consulting to ensure system reliability and compliance with Ontario Energy Board mandated requirements.

Budget - $50,000 = $50,000 in USoA 1925

Stores Warehouse Equipment

Complete the purchase, installation, and commissioning of a bar code system to improve efficiencies in warehouse operation and inventory management.

Budget - $20,000 = $20,000 in USoA 1935

Rolling Stock

Niagara-on-the-Lake Hydro has a scheduled replacement plan for all vehicles in our fleet as per our Asset Management Policy. No replacement is currently scheduled for 2009.

Budget - $0 = $0 in USoA 1930

Miscellaneous Equipment and Major Tools

This section covers Major Tools and Equipment for the Line Services and Engineering sections of Niagara-on-the-Lake Hydro.

Allocation for G.I.S. and SCADA upgrades, testing, commissioning and consultant costs required for the continuous improvement of our electrical system information storage and tracking capability.

Budget - $15,000 = $5,000 in USoA 1940 + $10,000 in 1980

Buildings and Fixtures

Improvements scheduled for 2009 are focused on exterior storage capacity. The leveling and paving of exterior storage areas for ease of access and safe passage of the fork lift vehicle, improved rack system to increase storage capacity and weight bearing capability.

Budget - $20,000 = $20,000 in USoA 1908

MATERIALITY ANALYSIS ON CAPITAL BUDGETS

The calculation of the Materiality Threshold on capital budgets is shown in the following table taken from **Exhibit 2, Tab 1, Schedule 2**

Table 2
Rate Base Materiality

Description	2006 OEB Approved	2006 Actual	2007 Actual Year	2008 Bridge Year	2009 Test Year
Gross Fixed Assets	$29,804,120	34,187,333.31	$35,241,416	$36,559,736	$38,437,232
Accumulated Depreciation	$12,124,061	15,004,356.37	$16,005,729	$17,282,748	$18,614,426
Net Book Value	$17,680,059	19,182,976.94	$19,235,687	$19,276,988	$19,822,807
Variance calc 1% NBV		$191,830	$192,357	$192,770	$198,228

:

NOTL Hydro uses the lowest materiality threshold of $191,830. The following list represents projects where this materiality is exceeded. These projects are also included in **Exhibit 2, Tab 3, Schedule 1**.

Village of Queenston Restoration/Upgrade

System enhancement project which includes voltage conversion and area improvement. System study demonstrated the age of the infrastructure in the Village of Queenston had exceeded its expected life and required replacement. The Municipality of Niagara-on-the-Lake requires through by-law that areas designated by the community as historic and tourist focused are to have all services buried when any new construction is undertaken. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system, and due to the Town by-law to bury all new servicing, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system in the Village of Queenston. This decision has the added benefit of reducing load on the 4kV St-David’s Station which is scheduled to be decommissioned in 2008.

2006 Cost $462,151
2007 Cost $34,602
2008 Cost $30,000
2009 Cost Nil

Queenston Road Conversion/Upgrade

System enhancement which includes voltage conversion and reinforcement for improved system inter-tie capability. As part of Niagara-on-the-Lake Hydro's General Plan to offload the 4kV System and Improve Operating Efficiency this project will improve overall line losses through both voltage conversion and the replacement of the existing conductor. The conductor replacement has a twofold benefit in this project as it allows greater system operational flexibility when completed by creating a tie point between York MTS1 and NOTL MTS2.

The work on this section of the project includes; replacement of all poles due to age and height requirements for the conversion from 4kV to 27.6kV, conductor ampacity upgrade as this section of line can be used as a feeder tie between York MTS1 and NOTL MTS2, secondary bus replacement, and new transformers. Work on this section of Line is on Queenston Road between Coon Road and Townline Road and at Queenston Road and York Road intersection.

2006 Cost $104,371
2007 Cost $41,094
2008 Cost $215,500
2009 Cost $200,000

York Road Conversion/Upgrade

System enhancement project which includes voltage conversion, system reliability, and improved operating efficiency through reduction in line losses. As part of Niagara-on-the-Lake Hydro's General Plan to offload the 4kV System this project will improve line losses through voltage conversion from 4kV to 27.6kV, improved customer power supply reliability by providing a second feed option from York MTS1 M1 feeder into Queenston Village and the Queenston/Lewiston International Bridge complex.

2006 Cost	$24,888
2007 Cost	$135,739
2008 Cost	$90,000
2009 Cost	$10,000

Chautauqua Project

System enhancement project which includes voltage conversion and area improvement. System study demonstrated the average age of the electrical plant in this Old Town urban area is approaching 50 years and annual plant inspections have indicated that a majority of the area is reaching the end of its useful life. The Town of Niagara-on-the-Lake has also committed to install new sewer and water lines in 2008/2009 and will commence construction in advance of our project. As part of the overall long term commitment to offload the 4kV system and improve overall line losses in the system and given the location within the urban boundaries of the Old Town, local by-laws require that we bury our new facilities, the decision was made to replace the existing 4kV pole line system with a 27.6kV underground system.

2006 Cost	Nil
2007 Cost	$1,106
2008 Cost	$300,000
2009 Cost	$1,000,000

Rolling Stock

Niagara-on-the-Lake Hydro has a scheduled replacement plan for all vehicles in our fleet as per our Asset Management Policy. In 2007 a new Line Services aerial truck was added to our fleet to replace two existing Line aerial trucks. It replaces the need for two vehicles in the fleet; one vehicle used exclusively for daily customer service work and 4kV primary work and a second vehicle used exclusively for 27.6kV construction work. Two vehicles were used due to the fact the customer service truck was not properly insulated to be used on 27.6kV primary.

A Line Services support vehicle has been replaced as per schedule in 2008. The new vehicle purchased has been assigned to the Engineering Services Department with Engineering's existing support vehicle re-assigned to Line Services.

2006 Cost	$24,883
2007 Cost	$250,400
2008 Cost	$30,000
2009 Cost	Nil

SYSTEM EXPANSIONS

2009 Test Year

NOTL Hydro system expansions in 2009 consist of Concession 7 (M1) tie to East West Line (M2) project and new Subdivision servicing.

2008 Bridge Year

System expansions in 2008 consist of new Subdivision servicing.

2007 Actual

System expansions in 2007 consisted of new Subdivision servicing.

2006 Actual

System expansions in 2006 consisted of new Subdivision servicing.

CAPITALIZATION POLICY:

NOTL Hydro has a capitalization policy that provides guidance and outlines the primary decisions for determining whether a specific purchase should be capitalized or expensed. Any decisions that are still not clearly defined by the policy involve further discussion and potentially the opinion of NOTL Hydro's independent auditor.

In general terms, a purchased item may be capitalized if 1) the useful life of an asset is extended, 2) the quality of the asset has been improved as a result, 3) productivity has improved as a result and 4) the value of the purchase is above a specified materiality threshold.

There are four main types of expenditures that can be considered for capitalization, namely 1) additions, 2) improvements (betterments) and replacements, 3) rearranging and reinstallations and 4) repairs. A decision flowchart is included in the policy to assist with the determination process.

The materiality value for capitalization consideration is $500.

ASSET MANAGEMENT POLICY:

The Asset Management Policy below forms the basis upon which NOTL Hydro capital programs are developed. This policy will be refined and updated over time to ensure its long-term effectiveness.

Niagara-on-the-Lake Hydro Inc.
Asset Management Policy

Overview

The intent of this policy is to provide direction for the efficient and optimal management of the company's significant assets. The assets are categorized as building and fixtures, computer hardware and software, SCADA system, distribution plant, transformer stations, metering, rolling stock and related equipment and tools and equipment. The definitions of these major asset categories are generally those defined in the Uniform System of Accounts from the O.E.B. Accounting Procedures Handbook, Section 230.

The terms of betterment (replacement or improvement) and repair are in conjunction with the definitions provided in Section 410 of the O.E.B. Accounting Procedures Handbook. This policy will provide guidance as to the betterment aspect of the assets only, whereas good utility practice is assumed for the ongoing maintenance and repair of such items. Betterment is defined as "…the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in previously 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 NOTL Hydro Capitalization Policy shall be used in conjunction with this Asset Management Policy.

Major Asset Categories and Replacement/Betterment Evaluation

1) Building and Fixtures

This asset account is generally reserved to capital additions at Niagara-on-the-Lake Hydro's #8 Henegan Road facilities at this time. Typical capitalized additions would include items such as renovation upgrades, new fixtures and appliances in accordance with the Capitalization Policy. **Unless prompted by unforeseen developments, the need for new items in this category are considered annually in coordination with the preparation of the Capital Budget.**

2) Computer Software and Hardware

Technological advancements in computer hardware, primarily in speed and functionality, combined with the increased reliance on IT support with older equipment has resulted in the development of an average 'lifecycle' of this equipment. In general, servers, laptops and personal computers are replaced after 3 or 4 years of service. Other hardware devices include printers, scanners, plotters, cell phones and computer peripherals such as monitors and keyboards. During the typical lifecycle, enhancements to memory or accessories may be required to extend the life of the unit. Replaced units are occasionally retained to provide workstations for temporary employees.

The purchase of new or latest version software is determined on 'value added' basis given that effective software can be an important productivity tool. The latest version of 'front office' software is commonly purchased with new hardware units while more department specific software such as GIS, CIS or financial are evaluated on a case by case basis. Numerous CIS enhancements are driven by market participation requirements. **An annual consideration of hardware and**

software upgrades or purchase is completed in conjunction with preparation of the Capital Budget.

3) SCADA System Equipment

SCADA equipment serves to provide remote control and data gathering of major distribution system components and transformer station equipment. The purchase of new or upgraded SCADA system apparatus is driven by the need to meet minimum Independent Electrical System Operator established operating criteria for transformer stations, safe and efficient control of distribution equipment and the need to obtain adequate and reliable field data. **Unless prompted by unforeseen developments, the need for new items in this category is considered annually in conjunction with preparation of the Capital Budget.**

4) Revenue and Wholesale Metering

Metering components commonly consist of meters, instrument transformers, connection wiring, housing or mounting equipment and communication equipment. New equipment is purchased in accordance with current Measurement Canada and Electrical Safety Authority approved standards. **The purchase of new revenue meters and equipment is predominantly driven by new customer requirements (growth) and retirement of older equipment in accordance with established good utility practice and long-term operating performance records. The value of such purchases is included in the annual capital budget.** . Meters and related equipment for wholesale metering points are similarly purchased and maintained in accordance with established Independent Electrical System Operator and Electrical Safety Authority established operating standards. **Enhancements to wholesale metering points may be considered on a positive cost to benefits basis.**

The implementation of irregular major purchases, such as for Smart Metering, would be prompted by a Regulation from the Minister of Energy.

5) Tools and Equipment

This asset category includes major garage and stores (inventory) tools such as weigh scales, carts compressors and power tools. Also included are distribution-related tools such as pole jacks, hydraulic presses and compression dies. Criteria for the purchase of new, replacement or upgraded items include improved ergonomics and safety, increased productivity or high operating costs/end of useful life. **Unless prompted by unforeseen developments, the need for new items in this category is generally considered annually upon preparation of the Capital Budget.**

6) Rolling Stock and Related Equipment

Rolling stock includes large operations vehicles, smaller pickups/vans, non-motorized trailers as well as riding mowers. Related equipment generally refers to accessory equipment that is normally affixed to the rolling stock such as emergency lighting, cabs and tool bins. The replacement of large operations vehicles is highly dependent on the condition of the unit. Annual independent testing of the vehicles' structural, hydraulic and mechanical components, combined with a tracking of regular maintenance cost are important determinants of scheduled replacement. Integral components such as the chassis can be replaced under a capital program resulting in extended life of the unit. Due to the substantial cost of these units, full replacement is normally scheduled a few years in advance. The replacement of pick-up trucks and vans is also included in the five year capital plan and normally follows a six to seven year lifecycle but will highly depend on the vehicles' mileage, maintenance cost and overall safety and mechanical evaluation. Other rolling assets are similarly replaced after a thorough inspection and determination of end of useful life. **Evaluation for**

replacement/upgrades are generally considered annually but slotted in a Five Year Plan.

7) <u>Transformer Stations</u>

The major assets of a transformer station include, but are not limited to, transformers, breakers, switches, structures and foundations, terminations and protective and control components. Regular maintenance and testing of the major components is critical to efficient operation and long life. Transformer units operated under ideal conditions have been known to provide over fifty years of service. Ongoing gas-in-oil analysis methods provide early warning of potential future problems and allow for corrective maintenance actions. Other components such as breakers provide an ‘operations counter’ that will signal timing of regular maintenance and signal end of useful life. The addition of latest technologies and components to enhance station reliability and operation must be evaluated by management on a value added to cost perspective basis. **Evaluation for replacement/upgrades are generally considered annually but slotted in a Five Year Plan.**

8) <u>Distribution Plant</u>

The largest component of the annual NOTL Hydro Capital Budget is the investment in Distribution Plant. The Ontario Energy Board’s Distribution System Code defines Distribution Plant capital as either an enhancement or an expansion with the following definitions; **“enhancement”** means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth. Whereas **“expansion”** means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system.

For annual capital budgeting purposes, Niagara-on-the-Lake Hydro further categorizes **enhancements** into 1) reinforcements 2) voltage conversions or 3) improvements

<u>Reinforcements</u> – Include elements of system fortification that result in improved operating control. Examples include new high voltage switches, additional feeder/breaker positions or replacing existing conductor with that of a greater load rating.

<u>Conversions</u> – Replacement of older 4.16 kV system with a more efficient 27.6 kV system. Distribution at 27.6 kV has proven to reduce line losses, which ultimately benefits customers, while mutually aiding the company through reduced operating and inventory costs.

<u>Improvements</u> – Aging distribution system components that have exceeded their useful life are primarily identified through annual inspections and ongoing analysis of outage logs. Examples of distribution improvements include pole replacements, upgraded secondary bus, transformers or insulators.

Niagara-on-the-Lake Hydro further categorizes **expansion** into 1) customer connections and 2) customer extensions recognizing that expansions are entirely customer driven.

<u>Customer Connections</u> – In accordance with our approved Conditions of Service, NOTL Hydro provides, through our rates, specific components and degrees of customer connections. For example, a residential customer will be supplied with overhead service wire, for up to one span off the street line, including transformation at no charge.

Customer Extensions – The Distribution Code directs our activities related to the quantity of capital provided in relation to a customer driven extension of distribution facilities along public right-of-ways.

Annual Process for Determining Distribution Plant Capital Investment

1) Area Improvements – Service Reliability indicators such as CAIDI and SAIFI, combined with outage statistics by feeder/area, call logs and the results of annual plant inspections are statistically analyzed annually to target areas in need of improvement. Improvement may include pole or conductor replacement, transformer upgrades or conversion to the 27.6 kV system.

2) Improve Operating Efficiency – The addition of new feeders, breakers, high voltage switches, larger conductor, transformer station capacity etc. can improve our ability to distribute electrical power more efficiently, reduce line losses and improve restoration time during emergency situations. Such planning would involve the use of DESS System Optimizing software.

3) General Plan to Offload the 4kV System – The legacy 4 kV distribution system and related transformer stations is generally less efficient to operate than the 27.6 kV system. Due to the lower operating voltage, the system requires an equivalent amperage output approximately 7 times higher than the 27.6 kV system to deliver the same quantity of power. During peak load periods, it is subject to voltage swings and the high amperage levels result in greater line losses. The 4 kV system involves the use of a ‘substation’ that transforms distribution voltage from 27.6 kV to 4 kV. These stations also have inherent losses and are subject to additional regular maintenance. Conversion of the 4 kV system is considered in a long term plan on an operational benefits plan and occasionally when system problems warrant replacement.

4) New Customer Growth - Customer growth (infill) patterns are studied annually to determine whether additional system reinforcement is required before potential problems surface. Other customer growth through line extensions and subdivisions require the application of the Capital Contribution Model which determines the amount of capital contribution (contributed capital) required by the developer or customer. Large projects are specifically included in the annual capital budget while smaller projects are generally funded from a miscellaneous fund in the annual budget. Customers may also request enhancements such as additional transformation capacity that require a combination of capital funding/customer contribution.

5) Road Authorities and By-Laws – Road authorities such as the Town of Niagara-on-the-Lake, Niagara Parks Commission and Niagara Region occasionally perform street widening or re-alignments that require the relocation or removal/re-routing of our distribution equipment. Many of these projects are only partially funded by the authority. The plant in question may require taller poles, for example, but is also evaluated for current age, condition and voltage level to determine potential capital investment. Capital investments are normally added to the capital budget when adequate time is provided. The Municipality of Niagara-on-the-Lake contains many tourist-focussed and historic sites that require our company through local by-laws to bury distribution facilities as a means of enhancing the streetscape or remaining visually unobtrusive. The additional cost of underground facilities is included in our capital budget.

Long-Term Process for Determining Distribution Plant Capital Investment

A five-year capital plan is maintained that outlines major projects and purchases. This plan is reviewed and updated annually and is instrumental in preparing the annual plan. The annual review of the Five Year Plan is necessitated since unforeseen customer growth, major equipment needs etc. can result in the occasional ‘shuffling’ of projects or purchases between years in the interest of efficiency or analyzed needs.

SERVICE RELIABILITY INDICES:

As indicated in the Asset Management Policy in **Exhibit 2, Tab 3, Schedule 5**, service reliability indices (SAIDI, SAIFI and CAIDI) are analyzed annually to determine areas in need of capital improvement. This analysis also is used for identifying asset maintenance that may be required.

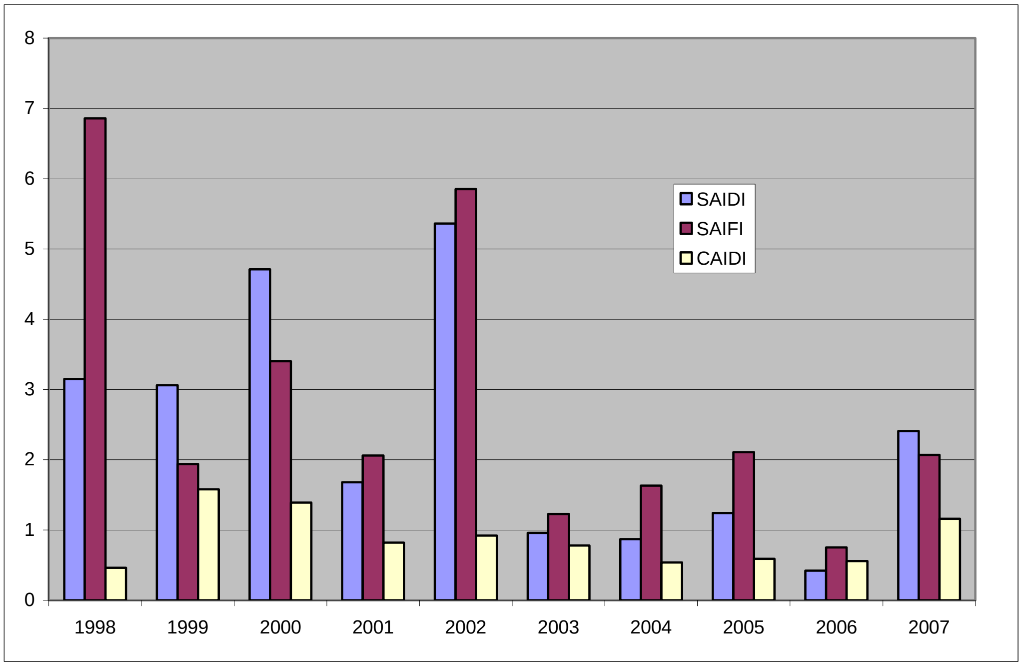
Table 1 and Chart 1 below provide the actual NOTL Hydro indices for the years 1998 to 2007:

Table 1

YEAR	SAIDI	SAIFI	CAIDI
1998	3.15	6.86	0.46
1999	3.06	1.94	1.58
2000	4.71	3.40	1.39
2001	1.68	2.06	0.82
2002	5.36	5.85	0.92
2003	0.96	1.23	0.78
2004	0.87	1.63	0.54
2005	1.24	2.11	0.59
2006	0.42	0.75	0.56
2007	2.41	2.07	1.16

		Units of Measure
SAIDI	"System Average Interruption Duration Index"	Hours per Customer
SAIFI	"System Average Interruption Frequency Index"	Interruptions per Customer
CAIDI	"Customer Average Interruption Duration Index"	Hours per Interruption

Chart 1



In 2003, NOTL Hydro commissioned a new Transformer Station (MTS 1) that effectively doubled the number of 27.6 kV feeders and included modern protection and control schemes. As a result of more lightly loaded and shorter feeder lengths, all three indices improved as evident in the Chart 1 results in 2003 and beyond. In late 2005, NOTL Hydro purchased the other supply transformer station (MTS 2) from Hydro One. The NOTL Hydro capital plan outlines the multi-year plan to modernize and improve the protection and control elements of this 25 year old station.

In general, the three service reliability indices are adversely affected by cyclic severe inclement weather patterns. NOTL Hydro's annual analysis of the indices is continuously cognizant of years that are above and below average storm activity levels.

WORKING CAPITAL CALCULATION:

- **OVERVIEW:**

NOTL Hydro's working capital allowance is forecast to be $2,190,718 for 2009 and is based on the "15% of specific O&M accounts formula approach" referred to at page 15 of the Board's Filing Requirements. NOTL Hydro has provided its calculations by account for each of 2006 Actual, 2007 Actual, the 2008 Bridge Year and the 2009 Test Year in Table 1 on the following page.

The accounts included in the calculation are eligible distribution expenses (operation, maintenance, billing and collecting, community relations, administrative and general expenses and taxes other than income tax and capital tax) and power supply expenses.

For power supply expenses in 2008 and 2009, as indicated in **Exhibit 2, Tab 1, Schedule 2**, NOTL Hydro has assumed a cost of power of $0.0672 per kWh in 2008 and $0.05373 per kWh in 2009 based on the Navigant Consulting report dated April 11, 2008 commissioned by the OEB. These prices, as well as the approved rates for the other components of power supply expenses (network, connection and wholesale market services) were multiplied by the weather normalized energy volumes as identified in **Exhibit 3, Tab 2, Schedule 2**, Table 10 to obtain the total power supply expenses.

Working Capital Calculation

Table 1
Working Capital Allowance Calculation by Account

Description	2006 Actual	Allowance for Working Capital	2007 Actual	Allowance for Working Capital	2008 Bridge	Allowance for Working Capital	2009 Test	Allowance for Working Capital
Rate used for Working Capital Allowance		15%		15%		15%		15%
Operation								
5005-Operation Supervision and Engineering	56,039	8,406	84,554	12,683	92,298	13,845	90,580	13,587
5010-Load Dispatching	2,072	311	0	0	30,679	4,602	30,683	4,602
5012-Station Buildings and Fixtures Expense	0	0	0	0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour	0	0	0	0	5,396	809	5,361	804
5015-Transformer Station Equipment - Operation Supplies and Expenses	1,735	260	(13,379)	(2,007)	12,950	1,943	13,250	1,988
5016-Distribution Station Equipment - Operation Labour	0	0	0	0	5,100	765	6,100	915
5017-Distribution Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	26,067	3,910	37,316	5,597	23,472	3,521	26,692	4,004
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	24,216	3,632	45,631	6,845	22,484	3,373	24,920	3,738
5030-Overhead Sub transmission Feeders - Operation	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	25,404	3,811	14,615	2,192	2,627	394	2,628	394
5040-Underground Distribution Lines and Feeders - Operation Labour	5,797	870	6,459	969	15,814	2,372	18,860	2,829
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	35,176	5,276	20,321	3,048	4,338	651	5,341	801
5050-Underground Sub transmission Feeders - Operation								
5055-Underground Distribution Transformers - Operation	3,035	455	14,963	2,244	2,837	425	2,882	432
5060-Street Lighting and Signal System Expense								
5065-Meter Expense	11,328	1,699	18,460	2,769	10,619	1,593	13,278	1,992
5070-Customer Premises - Operation Labour	7,934	1,190	8,307	1,246	9,458	1,419	7,986	1,198
5075-Customer Premises - Materials and Expenses	1,479	222	18,912	2,837	37,063	5,559	40,076	6,011
5085-Miscellaneous Distribution Expense	42,357	6,354	67,253	10,088	83,456	12,518	66,273	9,941
5090-Underground Distribution Lines and Feeders - Rental Paid								
5095-Overhead Distribution Lines and Feeders - Rental Paid	18,354	2,753	19,432	2,915	18,800	2,820	18,800	2,820
5096-Other Rent	0	0	0	0	0	0	0	0
Sub-Total	**260,994**	**39,149**	**342,844**	**51,427**	**377,390**	**56,608**	**373,710**	**56,057**

Maintenance								
5105-Maintenance Supervision and Engineering	42,122	6,318	52,255	7,838	79,928	11,989	79,394	11,909
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	51,585	7,738	49,015	7,352	13,263	1,989	20,785	3,118
5114-Maintenance of Distribution Station Equipment	7,019	1,053	13,252	1,988	4,755	713	5,272	791
5120-Maintenance of Poles, Towers and Fixtures	29,764	4,465	34,176	5,126	33,716	5,057	33,590	5,038
5125-Maintenance of Overhead Conductors and Devices	36,832	5,525	49,098	7,365	53,206	7,981	52,567	7,885
5130-Maintenance of Overhead Services	31,251	4,688	30,898	4,635	57,505	8,626	57,774	8,666
5135-Overhead Distribution Lines and Feeders - Right of Way	73,354	11,003	78,246	11,737	77,683	11,652	92,564	13,885
5145-Maintenance of Underground Conduit	902	135	2,794	419	1,100	165	1,100	165
5150-Maintenance of Underground Conductors and Devices	10,581	1,587	9,782	1,467	20,050	3,007	20,087	3,013
5155-Maintenance of Underground Services	28,028	4,204	73,310	10,996	53,205	7,981	53,253	7,988
5160-Maintenance of Line Transformers	65,473	9,821	20,554	3,083	62,941	9,441	88,680	13,302
5165-Maintenance of Street Lighting and Signal Systems								
5170-Sentinel Lights - Labour								
5172-Sentinel Lights - Materials and Expenses								
5175-Maintenance of Meters	12,049	1,807	17,936	2,690	17,321	2,598	16,294	2,444
5178-Customer Installations Expenses- Leased Property								
5185-Water Heater Rentals - Labour								
5186-Water Heater Rentals - Materials and Expenses								
5190-Water Heater Controls - Labour								
5192-Water Heater Controls - Materials and Expenses								
5195-Maintenance of Other Installations on Customer Premises								
Sub-Total	**388,961**	**58,344**	**431,315**	**64,697**	**474,671**	**71,201**	**521,359**	**78,204**
Billing and Collections								
5305-Supervision	3,028	454	10,399	1,560	12,861	1,929	13,530	2,030
5310-Meter Reading Expense	42,678	6,402	43,191	6,479	48,609	7,291	49,768	7,465
5315-Customer Billing	148,578	22,287	153,382	23,007	156,687	23,503	159,131	23,870
5320-Collecting	78,207	11,731	103,092	15,464	74,218	11,133	76,368	11,455
5325-Collecting- Cash Over and Short	(235)	(35)	19	3	0	0	0	0
5330-Collection Charges								
5335-Bad Debt Expense	37,947	5,692	45,524	6,829	20,000	3,000	20,000	3,000
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0	0	0	0	0
Sub-Total	**310,202**	**46,530**	**355,606**	**53,341**	**312,374**	**46,856**	**318,798**	**47,820**

Community Relations								
5405-Supervision	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	0	0	0	0	0	0	0	0
5415-Energy Conservation	29,210	4,381	8,136	1,220	0	0	0	0
5420-Community Safety Program	0	0	0	0	0	0	0	0
5425-Miscellaneous Customer Service and Informational Expenses	0	0	648	97	1,000	150	1,020	153
5505-Supervision								
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0
Sub-Total	**29,210**	**4,381**	**8,783**	**1,317**	**1,000**	**150**	**1,020**	**153**
Administrative and General Expenses								
5605-Executive Salaries and Expenses	55,508	8,326	60,293	9,044	63,826	9,574	67,260	10,089
5610-Management Salaries and Expenses	87,561	13,134	81,922	12,288	93,875	14,081	98,680	14,802
5615-General Administrative Salaries and Expenses	77,922	11,688	87,665	13,150	112,536	16,880	115,449	17,317
5620-Office Supplies and Expenses	24,011	3,602	46,801	7,020	25,510	3,827	25,430	3,815
5625-Administrative Expense Transferred Credit								
5630-Outside Services Employed	38,545	5,782	33,645	5,047	28,500	4,275	67,283	10,093
5635-Property Insurance	23,223	3,483	23,982	3,597	21,000	3,150	20,600	3,090
5640-Injuries and Damages	24,278	3,642	27,509	4,126	28,000	4,200	27,700	4,155
5645-Employee Pensions and Benefits	23,967	3,595	19,471	2,921	22,000	3,300	22,000	3,300
5650-Franchise Requirements								
5655-Regulatory Expenses	30,799	4,620	31,043	4,656	22,630	3,395	25,475	3,821
5660-General Advertising Expenses	1,907	286	1,500	225	1,000	150	1,020	153
5665-Miscellaneous General Expenses	93,193	13,979	73,908	11,086	50,000	7,500	50,450	7,568
5670-Rent								
5675-Maintenance of General Plant	76,168	11,425	87,849	13,177	114,807	17,221	123,057	18,459
5680-Electrical Safety Authority Fees	0	0	4,367	655	5,370	806	5,370	806
5685-Independent Market Operator Fees and Penalties								
Sub-Total	**557,082**	**83,562**	**579,955**	**86,993**	**589,054**	**88,358**	**649,774**	**97,466**
Property Taxes								
6105 - Property Taxes	30,833	4,625	33,846	5,077	33,800	5,070	33,450	5,018
Sub-Total	**30,833**	**4,625**	**33,846**	**5,077**	**33,800**	**5,070**	**33,450**	**5,018**
Cost of Power								
4705-Power Purchased	10,499,346	1,574,902	10,606,705	1,591,006	11,485,736	1,722,860	10,270,746	1,540,612
4708-Charges-WMS	914,998	137,250	942,723	141,408	1,180,036	177,005	1,189,256	178,388
4710-Cost of Power Adjustments	55,830	8,375	85,462	12,819	71,000	10,650	35,500	5,325
4712-Charges-One-Time								
4714-Charges-NW	967,924	145,189	1,006,699	151,005	918,884	137,833	886,554	132,983
4716-Charges-CN	153,133	22,970	440,179	66,027	347,926	52,189	324,619	48,693
4730-Rural Rate Assistance Expense	0	0	0	0	0	0	0	0
5685-Independent Market Operator Fees and Penalties								
Sub-Total	**12,591,231**	**1,888,685**	**13,081,768**	**1,962,265**	**14,003,582**	**2,100,537**	**12,706,676**	**1,906,001**
WORKING CAPITAL ALLOWANCE TOTAL	**14,168,512**	**2,125,277**	**14,834,118**	**2,225,118**	**15,791,872**	**2,368,781**	**14,604,787**	**2,190,718**

INDEX FOR EXHIBIT 3

OVERVIEW OF OPERATING REVENUE:

NOTL Hydro's operating revenue for 2006 (Board Approved and Actual), 2007 Actual, 2008 Bridge Year and 2009 Test Year is presented in this Exhibit. This Exhibit also provides a variance analysis by rate class of the material changes in operating distribution revenue components.

NOTL Hydro's distribution revenues have been calculated using the appropriate OEB-approved Schedule of Rates and Charges for the applicable year. Total distribution revenue includes OEB approved specific service charges, rent from electric property, late payment charges, interest and other miscellaneous revenues. A summary of operating revenues is presented in Table 1 of Tab 1, Schedule 2 below, and the variance analysis follows with individual explanations of distribution revenue and other distribution revenue.

Throughput Revenue:

Information related to NOTL Hydro's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume and customer counts. The variance analysis on the actual and forecast information is provided at Tab 2, Schedule 3 below.

Other Distribution Revenue:

This includes revenues such as late payment charges; specific service charges; Standard Supply Service Administration charges; rent from electric property; retail service revenues; miscellaneous service revenues; and interest. Details of these operating revenues are presented at Tab 3, Schedule 1 below.

Revenue Sharing:

NOTL Hydro does not engage in revenue sharing with affiliates.

SUMMARY OF OPERATING REVENUE TABLE:

The following Table 1 summarizes NOTL Hydro's total base distribution revenue requirement calculated on NOTL Hydro' forecasts, other distribution revenue and total service revenue requirement. The 2008 Bridge Year distribution revenue is based on NOTL Hydro 2008 OEB approved rates and NOTL Hydro forecast for customer counts and normalized usage. The proposed distribution revenue for 2009 has been calculated based on 2009 proposed distribution rates and 2009 forecast customer count and normalized usage.

Table 1
Summary of Operating Revenue ($)

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Normalized Current Rates	2009 Test Normalized Proposed Rates
Distribution Revenues (inc SSS Admin)					
Residential	1,996,674	1,913,785	2,147,292	2,174,476	2,397,869
General Service < 50 kW	1,005,887	818,707	1,031,204	995,214	1,188,290
General Service > 50 kW	1,195,539	1,236,826	1,341,769	1,331,049	1,121,414
Street Lighting	30,285	31,002	36,826	36,858	104,703
Sentinel Lighting	5,750	3,533	4,293	1,997	0
Unmetered Scattered Load	13,995	13,995	13,641	18,936	17,241
Base Distribution Revenue	**4,248,130**	**4,017,849**	**4,575,024**	**4,558,530**	**4,829,518**
Other Distribution Revenue					
Late Payment Charges	7,130	1,084	50,452	48,070	48,070
Specific Service Charges	46,492	49,282	48,700	45,430	45,430
Other Distribution Revenue	194,563	402,939	221,697	247,339	268,122
Total Other Revenue	**248,184**	**453,306**	**320,848**	**340,839**	**361,622**
Total Revenue Net of Tx Allowance	**4,496,315**	**4,471,154**	**4,895,872**	**4,899,369**	**5,191,140**

THROUGH PUT REVENUE

DISTRIBUTION REVENUE AND VARIANCE ANALYSIS:

NOTL Hydro distribution revenue and variance for 2006, 2007 and 2008 have been calculated using the OEB-approved distribution rates for 2006, 2007 and 2008. The 2009 distribution revenue has been calculated using the rates proposed in this Application as discussed further in Exhibit 9. Distribution revenue does not include commodity-related revenue.

NOTL Hydro has provided a variance of distribution revenues for 2006 Historical Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year in Table 1.

Table 1
Distribution Revenue with Variances

Description	2006 Board Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Normalized Current Rates	Variance from 2007 Actual	2009 Test Normalized Proposed Rates	Variance from 2008 Bridge
Distribution Revenues (inc SSS Admin)									
Residential	1,996,674	1,913,785	-82,889	2,147,292	233,506	2,174,476	27,184	2,397,869	223,393
General Service < 50 kW	1,005,887	818,707	-187,180	1,031,204	212,497	995,214	-35,990	1,188,290	193,076
General Service > 50 kW	1,195,539	1,236,826	41,288	1,341,769	104,942	1,331,049	-10,719	1,121,414	-209,635
Street Lighting	30,285	31,002	717	36,826	5,824	36,858	32	104,703	67,846
Sentinel Lighting	5,750	3,533	-2,217	4,293	760	1,997	-2,296	0	-1,997
Unmetered Scattered Load	13,995	13,995	0	13,641	-354	18,936	5,295	17,241	-1,695
Base Distribution Revenue	**4,248,130**	**4,017,849**	**-230,282**	**4,575,024**	**557,175**	**4,558,530**	**-16,494**	**4,829,518**	**270,988**
Other Distribution Revenue									
Late Payment Charges	7,130	1,084	-6,046	50,452	49,368	48,070	-2,382	48,070	0
Specific Service Charges	46,492	49,282	2,791	48,700	-583	45,430	-3,270	45,430	0
Other Distribution Revenue	194,563	402,939	208,377	221,697	-181,243	247,339	25,642	268,122	20,784
Total Other Revenue	**248,184**	**453,306**	**205,121**	**320,848**	**-132,457**	**340,839**	**19,990**	**361,622**	**20,784**
Total Revenue Net of Tx Allowance	**4,496,315**	**4,471,154**	**-25,160**	**4,895,872**	**424,718**	**4,899,369**	**3,497**	**5,191,140**	**291,772**

Materiality Threshold = 1% 40,178

Table 2 below highlights the material variances. The variance analysis follows the Table.

Table 2

Material Variances in Distribution Revenues

Description	2006 Board Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Normalized Current Rates	Variance from 2007 Actual	2009 Test Normalized Proposed Rates	Variance from 2008 Bridge
Distribution Revenues (inc SSS Admin)									
Residential	1,996,674	1,913,785	-82,889	2,147,292	233,506	2,174,476	0	2,397,869	223,393
General Service < 50 kW	1,005,887	818,707	-187,180	1,031,204	212,497	995,214	0	1,188,290	193,076
General Service > 50 kW	1,195,539	1,236,826	41,288	1,341,769	104,942	1,331,049	0	1,121,414	-209,635
Street Lighting	30,285	31,002	0	36,826	0	36,858	0	104,703	67,846
Sentinel Lighting	5,750	3,533	0	4,293	0	1,997	0	0	0
Unmetered Scattered Load	13,995	13,995	0	13,641	0	18,936	0	17,241	0
Base Distribution Revenue	**4,248,130**	**4,017,849**	**-230,282**	**4,575,024**	**557,175**	**4,558,530**	**-16,494**	**4,829,518**	**270,988**
Other Distribution Revenue									
Late Payment Charges	7,130	1,084	0	50,452	49,368	48,070	0	48,070	0
Specific Service Charges	46,492	49,282	0	48,700	0	45,430	0	45,430	0
Other Distribution Revenue	194,563	402,939	208,377	221,697	-181,243	247,339	0	268,122	0
Total Other Revenue	**248,184**	**453,306**	**205,121**	**320,848**	**-132,457**	**340,839**	**19,990**	**361,622**	**20,784**
Total Revenue Net of Tx Allowance	**4,496,315**	**4,471,154**	**-25,160**	**4,895,872**	**424,718**	**4,899,369**	**3,497**	**5,191,140**	**291,772**

Variance Analysis:

Consistent with the variance thresholds set out in the Filing Requirements with respect to rate base and operating costs, NOTL Hydro has used a variance of 1% of total base distribution revenue, as a means of determining a threshold for variance analysis. The threshold amount of $40,178 , calculated as 1% of the 2006 Actual, is used to analyze distribution revenues. The variance explanations by customer class are tabulated below in Tables 3 to 6.

NOTL Hydro has explained the majority of the variance in two main components: a price variance (due to increasing "current" rates to the "new" rates on "current" volumes) plus a volume variance (due to increasing "current" volumes to "new" volumes at the "new" rates). Thus, the volume variance is estimated as the difference in usage and the difference in the customer counts year over year times the variable or fixed distribution charge of the year used for the basis for the variance. (i.e. 2006 actual when 2007 actual is compared to 2006 actual). The price variance is calculated based on the usage and customer counts of the year being compared (i.e. 2007 actual when 2007 actual is compared to 2006 actual) times the difference in the distribution variable and fixed rate year over year.

In addition, the variances due to year-over-year SSS Admin charges, the PILs true-up in 2006 for 2005 PILS, in accordance with OEB guidelines, and differences due to the rate rounding applicable to 2009 rates are identified.

As shown in Tables 3 to 6 below, the majority of the distribution revenue variance for each rate class in each year is explained by the "price variance/volume variance" calculation procedure above.

Distribution Charges - Residential:

Table 3
Residential Class – Variance Analysis

	Description	2006 Board Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Normalized Current Rates	2009 Test Normalized Proposed Rates	Variance from 2008 Bridge
	Residential								
		A	B	C	D	E	F	H	I
	Price Variance			(B1-A1)xA3		(D1-B1)xB3			(H1-F1)xF3
1	Volumetric Rate	0.0122	0.0108	-$91,185	0.0123	$96,095	0.0123	0.0134	$72,363
			*	(B2-A2)xA4x12	*	(D2-B2)xB4x12			(H2-F2)xF4x12
2	Fixed Rate	17.34	16.20	-$80,503	17.45	$93,638	17.47	19.08	$125,754
	Total Price Variance			-171,689		189,733			198,117
	**Averaged to reflect May 1 change date*								
	Volume Variance			(B3-A3)*B1		(D3-B3)*D1			(H3-F3)*H1
3	kWh Volume	63,617,729	64,063,446	$4,799	65,499,951	$17,621	65,784,382	66,320,829	$7,188
				(B4-A4)xB2x12		(D4-B4)xD2x12			(H4-F4)xH2x12
4	Number of Customers	5,902	6,276	$72,721	6,424	$30,985	6,509	6,584	$17,172
	Total Volume Variance			$77,519		$48,606			$24,360
	PILs True-Up			-$20,251		$20,251			
	Miscellaneous Other Differences			$31,532		-$25,084			-$781
	Difference due to rate rounding								*$1,697*
	Total Residential Material Variance			-$82,889		$233,506			$223,393

Distribution Charges - General Service < 50 kW:

Table 4
GS<50 kW Class – Variance Analysis

Description	2006 Board Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Normalized Current Rates	2009 Test Normalized Proposed Rates	Variance from 2008 Bridge
GS <50kW								
	A	B	C	D	E	F	H	I
Price Variance			(B1-A1)xA3		(D1-B1)xB3			(H1-F1)xF3
1 Volumetric Rate	0.0119	0.0105	-$49,012	0.0120	$43,685	0.0120	0.0144	$82,948
		*	(B2-A2)xA4x12	*	(D2-B2)xB4x12			(H2-F2)xF4x12
2 Fixed Rate	39.59	36.98	-$38,568	39.83	$41,299	39.87	47.83	$115,811
Total Price Variance			-87,581		84,985			198,759
**Averaged to reflect May 1 change date*								
Volume Variance			(B3-A3)*B1		(D3-B3)*D1			(H3-F3)*H1
3 kWh Volume	35,862,790	30,478,041	-$56,719	34,969,161	$53,744	34,561,664	34,349,093	-$3,061
			(B4-A4)xB2x12		(D4-B4)xD2x12			(H4-F4)xH2x12
4 Number of Customers	1,233	1,209	-$10,651	1,216	$3,346	1,212	1,209	-$1,970
Total Volume Variance			-$67,371		$57,089			-$5,031
PILs True-Up			-$11,119		$11,119			
Miscellaneous Other Differences			-$21,110		$59,303			-$398
Difference due to rate rounding								*-$255*
Total GS <50kW Material Variance			-$187,180		$212,497			$193,076

Distribution Charges - General Service > 50 kW:

Table 5
GS>50 kW Class – Variance Analysis

Description	2006 Board Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Normalized Current Rates	2009 Test Normalized Proposed Rates	Variance from 2008 Bridge
GS >50kW								
	A	B	C	D	E	F	H	I
Price Variance			(B1-A1)xA3		(D1-B1)xB3			(H1-F1)xF3
1 Volumetric Rate	3.4413	3.0810	-$68,506	3.4620	$76,621	3.4654	2.8856	-$118,630
		*	(B2-A2)xA4x12	*	(D2-B2)xB4x12			(H2-F2)xF4x12
2 Fixed Rate	460.51	430.76	-$34,972	463.11	$45,424	463.48	370.25	-$130,895
Total Price Variance			-103,478		122,045			-249,525
**Averaged to reflect May 1 change date*								
Volume Variance			(B3-A3)*B1		(D3-B3)*D1			(H3-F3)*H1
3 kW Volume	190,118	201,104	$33,847	203,395	$7,931	204,605	207,437	$8,174
			(B4-A4)xB2x12		(D4-B4)xD2x12			(H4-F4)xH2x12
4 Number of Customers	98	117	$98,469	115	-$11,115	117	123	$27,341
Total Volume Variance			$132,316		-$3,183			$35,515
PILs True-Up			-$12,423		$12,423			
Miscellaneous Other Differences			$24,872		-$26,342			$4,387
Difference due to rate rounding								*-$12*
Total GS >50kW Material Variance			$41,288		$104,942			-$209,635

Distribution Charges - Street Lighting:

Table 6
Street Lighting Class – Variance Analysis

	Description	2008 Bridge Normalized Current Rates	2009 Test Normalized Proposed Rates	Variance from 2008 Bridge
	Street Lighting			
		F	H	I
	Price Variance			(H1-F1)xF3
1	Volumetric Rate	4.3107	11.79	$20,880
				(H2-F2)xF4x12
2	Fixed Rate	1.10	3.01	$43,060
	Total Price Variance			63,940
	Volume Variance			(H3-F3)*H1
3	kW Volume	2,791	2,900	$1,278
				(H4-F4)xH2x12
4	Number of Customers	1,880	1,953	$2,636
	Total Volume Variance			$3,914
	PILs True-Up			
	Miscellaneous Other Differences			-$8
	Difference due to rate rounding			*$0*
	Total Street Lighting Material Variance			$67,846

Other Distribution Revenue:

Details of the variance amounts for specific accounts within the category of other distribution revenue are shown in Table 7 below (also provided as Table 1 in **Exhibit 3, Tab 3, Schedule 1**). Material account variances exceeding the variance threshold amount are shown as shaded.

Table 7

Other Distribution Revenue and Variances ($)

Description of Other Revenue	2006 OEB Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual	2009 Test Year	Variance from 2008 Bridge
4080-SSS Admin	26,103	27,839	1,736	26,771	-1,067	29,362	2,591	29,703	341
4082-Retail Services Revenues	1,714	3,732	2,018	7,506	3,774	7,286	-220	7,286	0
4084-Service Transaction Requests (STR) Revenues	68	369	301	202	-167	218	16	218	0
4090-Electric Services Incidental to Energy Sales	33,522	112,430	78,909	0	-112,430	0	0	0	0
4210-Rent from Electric Property	52,720	69,027	16,307	70,743	1,716	70,000	-743	70,000	0
4225-Late Payment Charges	7,130	1,084	-6,046	50,452	49,368	48,070	-2,382	48,070	0
4235-Miscellaneous Service Revenues	46,492	49,282	2,791	48,700	-583	45,430	-3,270	45,430	0
4315-Revenues from electric plant leased to others	0	1,000	1,000	0	-1,000	0	0	0	0
4325-Revenues from Merchandise, Jobbing, Etc.	75,956	74,781	-1,175	59,028	-15,753	60,000	972	60,000	0
4335-Profits and Losses from Financial Instrument Hedges	0	0	0	33,911	33,911	34,000	89	34,000	0
4350/60-Gains/Losses from Disposition of Future Use Utility Plant	-18,635	14,849	33,484	-26,005	-40,854	-10,000	16,005	0	10,000
4390-Miscellaneous Non-Operating Income	8,707	20,487	11,780	17,105	-3,382	15,000	-2,105	15,000	0
4405-Interest and Dividend Income	14,409	78,426	64,017	32,436	-45,990	41,472	9,036	51,915	10,443
Totals	248,184	453,306	205,122	320,848	-132,457	340,839	19,990	361,622	20,784

- *Account 4090 – 2006 Actual vs 2006 Approved*

  and 2007 Actual vs 2006 Actual

Transformation revenue:

These variances are related to revenue from NOTL Hydro's two transformer stations which applied until April 30, 2006. Upon construction of one station ("York TS") and purchase of the other from Hydro One ("NOTL DS"), NOTL Hydro obtained OEB approval (RP-2003-0177/EB-2003-0219) for a transformation revenue rate of $1.50 per kW for incremental load over the base-load-trigger-point.

The 2006 actual variance from the OEB approved of $78,909 results from the OEB approved amount being based on the actual 2004 transformation revenue combined with a tier 1 adjustment in the 2006 EDR model. This calculation did not reflect the actual incremental loads that occurred in 2006.

After the asset value of these stations was brought into the rate base effective May 1, 2006, the transformation revenue rate was ended. Thus, there was no revenue in 2007 and the variance from the 2006 actual equates to the negative of the 2006 revenue amount, i.e. -$112,430 . There will be no transformation revenue in 2008 and beyond.

- *Account 4225 – 2007 Actual vs 2006 Actual*

Late Payment Charges:

The variance of $49,368 is due to NOTL Hydro's billing system not being able to calculate late payment charges in 2006 due to a system modification to associate multiple customer sites for the same customer as one customer file. Further modifications were then required to enable late payment charges to be calculated correctly. These modifications were completed in 2007 and late payment charges were implemented in that year.

- *Accounts 4350/4360 – 2007 Actual vs 2006 Actual*

Gains and Losses:

Effective December 31, 2007, NOTL Hydro disposed of its partnership interest known as the ENERconnect Limited Partnership. This disposal involved a loss of $44, 046, which formed the majority of the variance of -$40,854 . The remainder of the variance was normal year to year variation in the net amount of gains and losses.

- *Account 4405 – 2006 Actual vs 2006 Approved*

  and 2007 Actual vs 2006 Actual

Interest and dividend Income:

This account consists of interest on positive balances in the NOTL Hydro bank account at the bank's prevailing rate, carrying charge interest on balances of regulatory asset, deferral and variance accounts at the OEB-prescribed rate, and interest on loans to the affiliate, Energy Services Niagara Inc. at the same rate as applied to NOTL Hydro's bank account.

The variance of $64,017 of the 2006 actual from the 2006 approved (which is based on the 2004 actual) comprises $50,937 related to bank and affiliate loan interest and $13,080 resulting from the monthly debits and credits to the various regulatory asset, deferral and variance account balances. The bank and affiliate loan interest variance is mostly due to the increased affiliate loan in 2006 relative to 2004.

The variance of $-45,990 of the 2007 actual from the 2006 actual comprises $-37,669 resulting from the monthly debits and credits to the various regulatory asset, deferral and variance account balances and $-8,321 related to bank and affiliate loan interest.

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by NOTL Hydro's to prepare the weather normalized load and customer/connection forecast used to design the proposed distribution rates. In summary, NOTL Hydro reviewed the various processes used by the 2008 cost of service applicants and is proposing to adopt a weather normalization forecasting method similar to the one used by Toronto Hydro Electric System Ltd in its 2008, 2009 and 2010 rate application (EB-2007-0680).

Table 1 below provides a summary of the weather normalized load and customer/connection forecast used in this application. Historical data used was for a minimum past 5 years, 2003 to 2007, as required in the OEB filing guidelines.

Table 1
Summary of Load and
Customer/Connection Forecast

Year	Billed kWh	Growth kWh	Percent change	Customer/ Connection Count	Growth	Percent Change
2003	166,270,246			8,709		
2004	169,788,483	3,518,237	2.12%	8,967	258	2.96%
2005	179,968,717	10,180,234	6.00%	9,204	237	2.64%
2006	175,258,855	-4,709,862	-2.62%	9,439	235	2.55%
2007	180,475,098	5,216,243	2.98%	9,650	211	2.24%
2008 Normalized	181,247,811	772,713	0.43%	9,787	137	1.42%
2009 Normalized	182,664,024	1,416,212	0.78%	9,901	114	1.16%

2003 to 2007 are weather actual and 2008 and 2009 are weather normalized. NOTL Hydro currently does not have a process to adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit a process to forecast energy on a weather normalized basis has been developed and used in this application.

Total Customers are as of year-end and streetlight and unmetered loads measured as connections.

On a rate class basis actual and forecasted billed amount and number of customers are shown in Table 2

Table 2
Billed Energy and Number of Customers by Rate Class

Energy and customers by rate class

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load	Total
Energy (kWh)							
2003	59,473,068	35,010,423	70,539,226	884,324	145,274	217,931	166,270,246
2004	60,142,431	34,349,415	73,966,550	914,682	197,474	217,931	169,788,483
2005	67,990,535	34,479,068	76,163,682	995,698	121,803	217,931	179,968,717
2006	64,063,446	30,478,041	79,256,712	1,118,911	123,814	217,931	175,258,855
2007	65,499,951	34,969,161	78,684,896	1,002,185	100,974	217,931	180,475,098
2008 Normalized	65,784,382	34,561,664	79,505,118	1,045,473	49,006	302,169	181,247,811
2009 Normalized	66,320,829	34,349,093	80,605,864	1,086,069	0	302,169	182,664,024

Number of customers/connections							
2003	5,661	1,230	95	1,591	108	24	8,709
2004	5,902	1,227	98	1,611	105	24	8,967
2005	6,124	1,210	108	1,658	80	24	9,204
2006	6,276	1,209	117	1,736	77	24	9,439
2007	6,424	1,216	115	1,796	76	23	9,650
2008 Normalized	6,509	1,212	117	1,880	37	32	9,787
2009 Normalized	6,584	1,209	123	1,953	0	32	9,901

Table 3 summarizes the annual usage per customer/connection by rate class.

Table 3

Annual Usage per Customer/Connection by Rate Class

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load
Energy usage per customer/connection (kWh per customer/connection)						
2003	10,506	28,464	742,518	556	1,345	9,080
2004	10,190	27,995	754,761	568	1,881	9,080
2005	11,102	28,495	705,219	601	1,523	9,080
2006	10,208	25,209	677,408	645	1,608	9,080
2007	10,196	28,758	684,216	558	1,329	9,475
2008 Normalized	10,107	28,506	679,531	556	1,324	9,443
2009 Normalized	10,073	28,411	654,514	556	n/a	9,443

Annual growth rate in usage per customer/connection						
2003						
2004	-3.0%	-1.6%	1.6%	2.1%	39.8%	0.0%
2005	9.0%	1.8%	-6.6%	5.8%	-19.0%	0.0%
2006	-8.1%	-11.5%	-3.9%	7.3%	5.6%	0.0%
2007	-0.1%	14.1%	1.0%	-13.4%	-17.4%	4.3%
2008 Normalized	-0.9%	-0.9%	-0.7%	-0.3%	-0.3%	-0.3%
2009 Normalized	-0.3%	-0.3%	-3.7%	0.0%	n/a	0.0%

LOAD FORECAST AND METHODOLOGY

NOTL Hydro weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on multifactor regression model that incorporates historical load, weather, and economic data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using company knowledge of local economic conditions, residential development opportunities and status of specific key customers where applicable. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

Purchased KWh Load Forecast

The forecast of total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days), economic output (GDP growth) and seasonal calendar variables. The regression model uses monthly kWh purchased by NOTL Hydro and monthly values of the independent variables from January 1996 to March 2008 to determine the monthly regression coefficients.

Data for NOTL Hydro's total system load is available as far back as January 1996 which provides 147 monthly data points to March 2008* and this is a reasonable data set for use in a multiple regression analysis. Based on the recent global activity surrounding climate change historical weather data is showing that there is a warming of the global climate system. In this regard it is NOTL Hydro’s view that it is appropriate to review the impact of weather since 1996 on the energy usage and then determine the average weather conditions from 1996 which would be applied in the forecasting process to determine a weather normalized forecast.

*(*Note: the January to March 2008 actual data were only used to develop the regression model and are not included in the weather normalized amounts for 2008 since they are not weather normalized.)*

The multifactor regression model has determined that the primary drivers of year-over-year changes in NOTL Hydro's load growth are economic conditions and weather. Both of these effects are captured within the multifactor regression model.

Economic growth – which encompasses both growth in the NOTL Hydro customer base as well as general economic conditions - is captured in the model using an index of economic output, Ontario Real Gross Domestic Product ("GDP").

Weather impacts on load are apparent in both the winter heating season and the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days i.e. a measure of summer heat) are modelled.

The third main factor determining energy use in the monthly model can be classified as "calendar factors". The best-predictor model of purchased energy uses two “flag” variables – one to capture the typically lower usage in the early spring months between winter and summer (March to May), and the other to capture typically higher usage in the summer and tourist months in Niagara-on-the-Lake (July to September).

The process of developing a model of energy usage involves estimating multifactor models using different input variables to determine the best fit. Using stepwise regression techniques different explanatory variables were tested using the proprietary statistical software XLSTAT (an add-in for Microsoft Excel) with the ultimate model being determined both by model statistics and by forecast accuracy. XLSTAT supports the following criteria for evaluating the results of regression runs:

- Adjusted R^2 for goodness of fit of the model
- t-stats for significance of independent variables
- F-Test for significance of the regression
- Mean Absolute Percent Error
- Durbin Watson test for serial correlation
- Minimum AIC criterion
- Press RMSE vs RMSE
- Cook's distance statistic for influential points.

The results of the model testing are shown in Table 4 below.

Table 4

Regression Model Evaluation

	Model 1	Model 2	Model 3	Model 3a	Model 4	Model 5	Model 6	Model 7	Model 8	Model 9	Model 10	Model 11	Model 12	Model 13	Model 14	Model 15	Model 16
Independent Variables (t-stats)																	
Constant Value	-2.09	-1.51	-2.50	-2.56	-2.32	-2.23	1.64	-10.00	-9.97	-9.32	-7.34	-7.03	-5.40	-2.56	-7.14	-0.35	-0.99
Population	1.68																
Ontario GDP Index	5.16	28.56	29.23	29.59	29.04	29.34	29.87	37.35	37.33	37.24	37.21	37.24	37.22	29.63	31.29	24.63	25.06
Peak Hours	1.17					1.37				-0.59	-0.58						
Peak Hours %							-2.84					-0.59	-0.59				
Days in Month								9.52		9.36		8.84			6.49		
Days in Month squared									9.51		9.34		8.82				
18°C Heating Degree Days	8.65	7.59	12.30	12.78	10.43	12.41	12.30	15.52	15.43	15.37	15.28	15.38	15.29	12.68	14.98	8.49	9.20
18°C Cooling Degree Days	19.11	18.02	16.76	17.06	15.17	16.37	17.36	19.91	19.85	19.77	19.71	15.38	19.70	17.05	18.75		15.24
21°C Cooling Degree Days																13.40	
Summer Flag	3.82	3.29	7.00	6.98	4.73	7.16	6.39	8.35	8.34	8.03	8.02	8.02	8.01	7.11	8.54	9.48	
Winter Flag	-3.88																
Spring Flag	-3.98	-3.89															
Adj. Summer Flag																	-2.22
Adj. Spring Flag			-4.42	-4.33	-4.15	-4.56	-4.63	-7.89	-7.88	-7.83	-7.82	-7.83	-7.83	-4.69		-5.60	-5.46
June Flag					-0.19												
Leap Year Feb Flag														-2.25			
Model Statistics																	
Adj-R^2	93.1%	92.4%	92.6%	92.9%	92.6%	92.7%	93.0%	95.5%	95.5%	95.5%	95.5%	95.5%	95.5%	92.8%	93.5%	90.3%	90.4%
F-Test	248	356	367	378	304	308	322	515	515	440	439	440	439	315	423	272	275
Mean Absolute Percent Error	3.44	3.65	3.64	3.59	3.64	3.66	3.39	2.67	2.67	2.65	2.65	2.65	2.65	3.59	3.34	3.90	4.00
Durbin-Watson	1.789	1.522	1.854	1.869	1.858	1.823	1.837	1.186	1.186	1.179	1.179	1.179	1.179	1.804	1.189	2.198	1.709
AIC	3,916	3,928	3,924	3,891	3,925	3,924	3,917	3,852	3,852	3,854	3,854	3,878	3,854	3,920	3,904	3,964	3,962
Press RMSE/RMSE	1.069	1.045	1.044	1.041	1.050	1.051	1.052	1.058	1.058	1.065	1.065	1.065	1.065	1.053	1.047	1.058	1.051
Cook's Distance Statistic	Calculated for each observation within each model. Model 3 has one observation with relatively large Cook's distance.																
Estimation Period	January 1996 to March 2008																

The model chosen as the best predictor of kWh purchased by NOTL Hydro is Model 3a. This model differs from the next best model, model 3, by omitting the data for one month (July 1999) which appears to be unusual as indicated by Cook's distance statistic, possibly indicating a measurement error in the data. Excluding this month, there are 146 monthly data points to March 2008 and this is a reasonable data set for use in a multiple regression analysis

The chosen model 3a is follows:

NOTL Hydro Monthly Predicted kWh Purchases

= Heating Degree Days x 4,112

+ Cooling Degree Days x 32,941

+ Ontario Real GDP Monthly Index x 103,870

+ Early Spring Flag x -544,380

+ Summer Flag x 1,292,074

+ Constant of -1,151,930

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Table 5 below.

Table 5

Monthly Data Used in Regression Analysis

Month/Year	NOTL Purchased	Ontario Real GDP Monthly %	Heating Degree Days	Cooling Degree Days	Summer Flag	Early Spring Flag	Predicted Purchases Model 3a	Variances (kWh) [Model 3a]	% Variance
Jan-96	12,502,629	95.7	709	0	0	0	11,697,076	805,553	-6.4%
Feb-96	11,504,822	95.8	651	0	0	0	11,469,209	35,613	-0.3%
Mar-96	11,558,341	95.8	613	0	0	1	10,777,970	780,371	-6.8%
Apr-96	10,081,641	95.9	382	0	0	1	9,838,000	243,641	-2.4%
May-96	9,844,919	96.0	174	13	0	1	9,412,192	432,727	-4.4%
Jun-96	10,453,919	96.1	8	68	0	0	11,108,399	-654,480	6.3%
Jul-96	11,888,649	96.2	5	89	1	0	13,089,319	-1,200,670	10.1%
Aug-96	13,630,712	96.3	1	131	1	0	14,448,946	-818,234	6.0%
Sep-96	11,568,448	96.4	66	32	1	0	11,471,459	96,989	-0.8%
Oct-96	10,739,347	96.5	224	2	0	0	9,851,052	888,295	-8.3%
Nov-96	11,382,512	96.6	491	0	0	0	10,900,646	481,866	-4.2%
Dec-96	11,982,545	96.7	531	0	0	0	11,077,247	905,298	-7.6%
Jan-97	12,523,563	96.8	706	0	0	0	11,806,040	717,523	-5.7%
Feb-97	10,534,404	97.1	535	0	0	0	11,137,024	-602,620	5.7%
Mar-97	11,157,735	97.5	548	0	0	1	10,683,160	474,575	-4.3%
Apr-97	9,796,251	97.8	362	0	0	1	9,951,491	-155,240	1.6%
May-97	9,682,362	98.2	237	0	0	1	9,477,333	205,029	-2.1%
Jun-97	11,112,777	98.5	18	64	0	0	11,262,847	-150,070	1.4%
Jul-97	12,761,684	98.9	7	100	1	0	13,724,915	-963,231	7.5%
Aug-97	12,911,556	99.2	7	58	1	0	12,393,925	517,631	-4.0%
Sep-97	11,166,200	99.6	60	18	1	0	11,325,853	-159,653	1.4%
Oct-97	10,878,920	99.9	237	7	0	0	10,437,136	441,784	-4.1%
Nov-97	11,283,929	100.3	440	0	0	0	11,074,351	209,578	-1.9%
Dec-97	12,104,164	100.6	544	0	0	0	11,540,386	563,778	-4.7%
Jan-98	12,025,224	101.0	582	0	0	0	11,731,077	294,147	-2.4%
Feb-98	10,422,047	102.1	480	0	0	0	11,425,133	-1,003,086	9.6%
Mar-98	11,207,633	103.1	428	2	0	1	10,824,351	383,282	-3.4%
Apr-98	9,741,038	103.6	269	0	0	1	10,171,898	-430,860	4.4%
May-98	10,680,353	104.1	61	28	0	1	10,287,691	392,662	-3.7%
Jun-98	12,119,728	104.6	51	83	0	0	12,654,652	-534,924	4.4%
Jul-98	14,386,013	105.2	3	112	1	0	14,773,157	-387,144	2.7%
Aug-98	15,439,866	105.8	1	125	1	0	15,262,495	177,371	-1.1%
Sep-98	12,625,438	106.5	22	57	1	0	13,176,197	-550,759	4.4%
Oct-98	11,287,268	107.4	198	1	0	0	10,833,480	453,788	-4.0%
Nov-98	11,223,313	108.4	363	0	0	0	11,600,520	-377,207	3.4%
Dec-98	12,223,679	109.4	499	0	0	0	12,263,562	-39,883	0.3%
Jan-99	13,208,170	110.0	692	0	0	0	13,116,948	91,222	-0.7%
Feb-99	11,030,833	110.7	516	0	0	0	12,468,901	-1,438,068	13.0%
Mar-99	11,836,338	111.4	538	0	0	1	12,088,507	-252,169	2.1%
Apr-99	10,336,685	112.2	296	0	0	1	11,173,317	-836,632	8.1%
May-99	10,811,899	113.0	95	19	0	1	11,061,633	-249,734	2.3%
Jun-99	13,309,510	113.8	24	104	0	0	14,175,773	-866,263	6.5%
Jul-99	16,692,168	114.3	2	191	1	0	18,327,318	-1,635,150	9.8%
Aug-99	14,865,568	114.7	5	79	1	0	14,690,563	175,005	-1.2%
Sep-99	13,426,087	115.2	35	44	1	0	13,684,497	-258,410	1.9%
Oct-99	11,599,574	115.9	231	0	0	0	11,837,438	-237,864	2.1%
Nov-99	11,841,006	116.5	339	0	0	0	12,341,547	-500,541	4.2%
Dec-99	13,353,197	117.2	541	0	0	0	13,245,202	107,995	-0.8%

Month/Year	NOTL Purchased	Ontario Real GDP Monthly %	Heating Degree Days	Cooling Degree Days	Summer Flag	Early Spring Flag	**Predicted Purchases Model 3a**	Variances (kWh) [Model 3a]	% Variance
Jan-00	13,530,386	117.5	690	0	0	0	13,889,397	-359,011	2.7%
Feb-00	12,128,756	117.9	556	0	0	0	13,380,818	-1,252,062	10.3%
Mar-00	11,769,707	118.2	418	0	0	1	12,299,383	-529,676	4.5%
Apr-00	11,213,639	118.4	328	0	0	1	11,951,350	-737,711	6.6%
May-00	11,458,319	118.5	120	17	0	1	11,669,415	-211,096	1.8%
Jun-00	12,646,169	118.7	39	62	0	0	13,379,764	-733,595	5.8%
Jul-00	14,174,031	119.1	0	84	1	0	15,269,093	-1,095,062	7.7%
Aug-00	16,101,013	119.6	8	102	1	0	15,953,040	147,973	-0.9%
Sep-00	13,854,501	120.0	71	40	1	0	14,207,148	-352,647	2.5%
Oct-00	12,543,952	120.0	187	2	0	0	12,133,048	410,904	-3.3%
Nov-00	12,658,677	119.9	370	0	0	0	12,823,398	-164,721	1.3%
Dec-00	14,588,347	119.9	680	0	0	0	14,095,925	492,422	-3.4%
Jan-01	13,755,848	120.0	622	0	0	0	13,867,842	-111,994	0.8%
Feb-01	12,202,985	120.0	552	0	0	0	13,582,500	-1,379,515	11.3%
Mar-01	13,113,484	120.1	563	0	0	1	13,094,968	18,516	-0.1%
Apr-01	11,332,498	120.5	274	2	0	1	12,007,775	-675,277	6.0%
May-01	11,763,961	120.9	107	11	0	1	11,678,311	85,650	-0.7%
Jun-01	14,136,292	121.3	33	74	0	0	14,010,571	125,721	-0.9%
Jul-01	16,055,092	121.2	7	101	1	0	16,091,237	-36,145	0.2%
Aug-01	18,933,691	121.0	0	156	1	0	17,853,855	1,079,836	-5.7%
Sep-01	14,596,638	120.8	66	26	1	0	13,814,688	781,950	-5.4%
Oct-01	13,331,992	121.3	198	5	0	0	12,435,806	896,186	-6.7%
Nov-01	12,715,774	121.7	295	0	0	0	12,702,409	13,365	-0.1%
Dec-01	13,993,294	122.1	483	0	0	0	13,515,697	477,597	-3.4%
Jan-02	14,148,180	122.6	552	0	0	0	13,851,740	296,440	-2.1%
Feb-02	12,641,587	123.2	515	0	0	0	13,760,290	-1,118,703	8.8%
Mar-02	13,657,015	123.8	515	0	0	1	13,279,466	377,549	-2.8%
Apr-02	12,616,129	124.0	303	11	0	1	12,800,414	-184,285	1.5%
May-02	12,946,863	124.2	212	9	0	1	12,373,738	573,125	-4.4%
Jun-02	14,674,061	124.4	33	78	0	0	14,479,570	194,491	-1.3%
Jul-02	18,274,752	124.9	0	168	1	0	18,650,948	-376,196	2.1%
Aug-02	19,081,341	125.4	0	148	1	0	18,048,178	1,033,163	-5.4%
Sep-02	16,407,410	125.9	17	84	1	0	16,061,367	346,043	-2.1%
Oct-02	13,790,066	126.1	261	11	0	0	13,385,292	404,774	-2.9%
Nov-02	13,598,163	126.2	424	0	0	0	13,698,161	-99,998	0.7%
Dec-02	15,084,566	126.4	598	0	0	0	14,435,990	648,576	-4.3%
Jan-03	15,605,142	126.8	766	0	0	0	15,169,514	435,628	-2.8%
Feb-03	13,777,511	127.2	670	0	0	0	14,816,764	-1,039,253	7.5%
Mar-03	13,886,125	127.5	528	0	0	1	13,718,881	167,244	-1.2%
Apr-03	12,732,906	127.4	375	0	0	1	13,079,837	-346,931	2.7%
May-03	12,550,053	127.2	161	0	0	1	12,177,545	372,508	-3.0%
Jun-03	13,748,210	127.0	36	42	0	0	13,582,260	165,950	-1.2%
Jul-03	16,691,749	126.7	1	119	1	0	17,212,680	-520,931	3.1%
Aug-03	18,092,812	126.4	2	124	1	0	17,350,336	742,476	-4.1%
Sep-03	14,888,714	126.0	32	37	1	0	14,582,723	305,991	-2.1%
Oct-03	13,889,177	126.4	234	5	0	0	13,114,794	774,383	-5.6%
Nov-03	13,623,711	126.9	361	0	0	0	13,513,075	110,636	-0.8%
Dec-03	14,991,479	127.3	532	0	0	0	14,259,344	732,135	-4.9%

Month/Year	NOTL Purchased	Ontario Real GDP Monthly %	Heating Degree Days	Cooling Degree Days	Summer Flag	Early Spring Flag	**Predicted Purchases Model 3a**	Variances (kWh) [Model 3a]	% Variance
Jan-04	16,050,658	127.4	750	0	0	0	15,165,640	885,018	-5.5%
Feb-04	14,148,177	127.5	579	0	0	0	14,471,717	-323,540	2.3%
Mar-04	14,273,134	127.7	471	0	0	1	13,503,241	769,893	-5.4%
Apr-04	12,863,305	128.3	300	1	0	1	12,906,544	-43,239	0.3%
May-04	13,398,133	128.9	132	14	0	1	12,692,360	705,773	-5.3%
Jun-04	14,135,802	129.6	53	33	0	0	13,605,162	530,640	-3.8%
Jul-04	16,671,355	130.2	2	88	1	0	16,555,453	115,902	-0.7%
Aug-04	17,143,727	130.9	9	63	1	0	15,839,181	1,304,546	-7.6%
Sep-04	15,916,123	131.5	26	46	1	0	15,434,871	481,252	-3.0%
Oct-04	13,910,480	131.9	209	1	0	0	13,422,707	487,773	-3.5%
Nov-04	13,805,540	132.2	362	0	0	0	14,067,494	-261,954	1.9%
Dec-04	15,835,971	132.5	580	0	0	0	14,993,536	842,435	-5.3%
Jan-05	16,331,485	132.6	694	0	0	0	15,475,518	855,967	-5.2%
Feb-05	13,966,621	132.8	554	0	0	0	14,919,852	-953,231	6.8%
Mar-05	14,896,809	133.0	561	0	0	1	14,424,616	472,193	-3.2%
Apr-05	12,976,713	133.2	291	0	0	1	13,335,681	-358,968	2.8%
May-05	13,102,698	133.4	178	0	0	1	12,890,204	212,494	-1.6%
Jun-05	17,368,816	133.7	8	129	0	0	17,008,357	360,459	-2.1%
Jul-05	19,805,768	133.9	0	160	1	0	19,302,488	503,280	-2.5%
Aug-05	19,394,910	134.2	1	149	1	0	19,005,055	389,855	-2.0%
Sep-05	16,134,163	134.5	16	67	1	0	16,376,956	-242,793	1.5%
Oct-05	14,385,984	134.6	210	18	0	0	14,277,150	108,834	-0.8%
Nov-05	14,028,139	134.7	352	0	0	0	14,287,905	-259,766	1.9%
Dec-05	16,177,808	134.9	623	0	0	0	15,421,266	756,542	-4.7%
Jan-06	15,068,183	135.2	540	0	0	0	15,110,757	-42,574	0.3%
Feb-06	13,944,271	135.4	606	0	0	0	15,403,716	-1,459,445	10.5%
Mar-06	14,286,598	135.7	504	0	0	1	14,471,941	-185,343	1.3%
Apr-06	12,746,759	136.0	271	0	0	1	13,543,875	-797,116	6.3%
May-06	13,662,946	136.3	135	22	0	1	13,739,331	-76,385	0.6%
Jun-06	15,421,790	136.6	17	61	0	0	15,111,117	310,673	-2.0%
Jul-06	19,240,751	136.9	0	168	1	0	19,877,627	-636,876	3.3%
Aug-06	18,721,230	137.2	3	106	1	0	17,883,718	837,512	-4.5%
Sep-06	14,886,931	137.4	71	12	1	0	15,100,790	-213,859	1.4%
Oct-06	14,675,076	137.7	262	0	0	0	14,228,653	446,423	-3.0%
Nov-06	14,306,931	138.0	360	0	0	0	14,663,980	-357,049	2.5%
Dec-06	15,491,961	138.3	445	0	0	0	15,043,801	448,160	-2.9%
Jan-07	15,851,415	138.6	578	0	0	0	15,620,977	230,438	-1.5%
Feb-07	15,178,391	138.9	658	0	0	0	15,980,241	-801,850	5.3%
Mar-07	15,217,726	139.1	514	0	0	1	14,866,215	351,511	-2.3%
Apr-07	13,669,243	139.4	362	0	0	1	14,272,009	-602,766	4.4%
May-07	13,835,998	139.7	158	14	0	1	13,911,589	-75,591	0.5%
Jun-07	16,594,307	140.0	11	82	0	0	16,126,020	468,287	-2.8%
Jul-07	17,565,527	140.2	0	109	1	0	18,293,344	-727,817	4.1%
Aug-07	19,544,883	140.5	7	143	1	0	19,455,991	88,892	-0.5%
Sep-07	16,060,666	140.8	19	55	1	0	16,645,906	-585,240	3.6%
Oct-07	14,549,269	141.1	103	21	0	0	14,606,250	-56,981	0.4%
Nov-07	14,298,213	141.4	385	0	0	0	15,119,928	-821,715	5.7%
Dec-07	16,140,952	141.6	567	0	0	0	15,887,772	253,180	-1.6%

Month/Year	NOTL Purchased	Ontario Real GDP Monthly %	Heating Degree Days	Cooling Degree Days	Summer Flag	Early Spring Flag	**Predicted Purchases Model 3a**	Variances (kWh) [Model 3a]	% Variance
Jan-08	15,813,114	141.9	657	0	0	0	16,287,158	-474,044	3.0%
Feb-08	15,009,236	142.2	573	0	0	0	15,972,708	-963,472	6.4%
Mar-08	15,088,622	142.5	517	0	0	1	15,234,354	-145,732	1.0%
Apr-08		142.7	318	1	0	1	14,471,843		
May-08		143.0	148	12	0	1	14,166,409		
Jun-08		143.3	28	73	0	0	16,257,868		
Jul-08		143.6	2	124	1	0	19,148,670		
Aug-08		143.9	3	115	1	0	18,900,614		
Sep-08		144.1	42	43	1	0	16,700,513		
Oct-08		144.4	213	6	0	0	14,918,262		
Nov-08		144.7	379	0	0	0	15,434,450		
Dec-08		145.0	552	0	0	0	16,178,539		
Jan-09		145.3	657	0	0	0	16,640,317		
Feb-09		145.5	573	0	0	0	16,315,480		
Mar-09		145.8	517	0	0	1	15,577,126		
Apr-09		146.1	318	1	0	1	14,825,002		
May-09		146.4	148	12	0	1	14,519,569		
Jun-09		146.7	28	73	0	0	16,611,027		
Jul-09		146.9	2	124	1	0	19,491,442		
Aug-09		147.2	3	115	1	0	19,243,386		
Sep-09		147.5	42	43	1	0	17,053,672		
Oct-09		147.8	213	6	0	0	15,271,421		
Nov-09		148.1	379	0	0	0	15,787,610		
Dec-09		148.3	552	0	0	0	16,521,311		

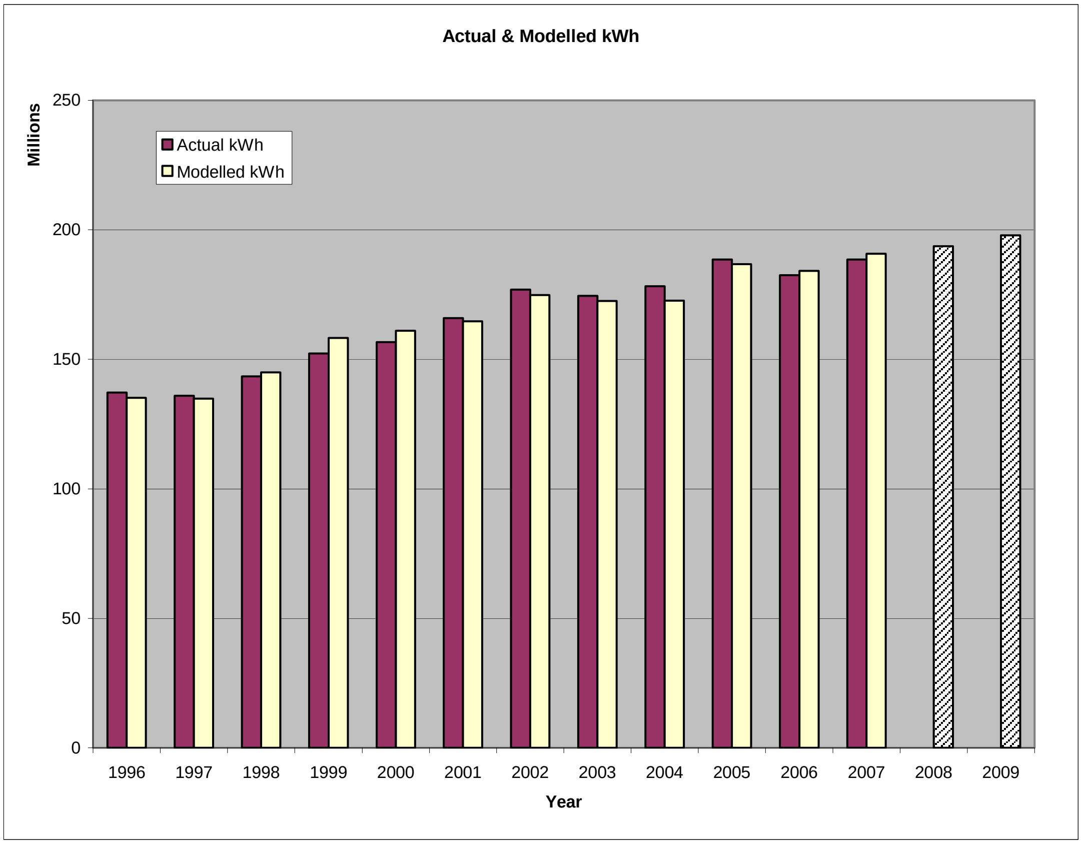
The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. All data for the 147 months from January 1996 to March 2008 was from weather stations bordering on Niagara-on-the-Lake. The weather station data used by Hydro One for NOTL Hydro's cost allocation review in 2006 used data from Windsor. Windsor being some 380 km distant from Niagara-on-the-Lake, data from this station was felt to be unsuitable for the current application. For most of the period from January 1996 to March 2008, data from the Environment Canada weather station at the Niagara Parks Commission School of Horticulture was used. Some gaps in this data existed. In these cases, data from other nearby stations was used. For 21 months of the 147, the Environment Canada station at Port Weller was used. For 1 month of the 147, the Environment Canada station at St. Catharines Power Glen was used.

b) The 2008, 2009 and 2010 rate application (EB-2007-0680) for Toronto Hydro Electric System Ltd provided the Ontario real GDP monthly index and;.

c) The calendar provided information related to the early spring (March to May) and summer (July to September) flags.

The annual results of the above prediction formula compared to the actual annual purchases from 1996 to 2007 and the modeled result of the prediction formula for 2008 and 2009 are shown in the chart below. The modeled amounts for 2008 and 2009 are determined by using a forecast of the dependent variables in the prediction formula on a monthly basis. In order to incorporate weather normal conditions, the average monthly heating degree days and cooling degree days for each calendar month which have occurred from 1996 to 2007 are applied in the prediction formula. The details on the average monthly heating degree days and cooling degree days are shown in the table of monthly data presented earlier in this Schedule.



The following table outlines the data that supports the above chart.

Table 6
NOTL Hydro Total System Purchases

Year	Actual kWh	Modelled kWh	% Difference
1996	137,138,484	135,141,514	-1.5%
1997	135,913,545	134,814,460	-0.8%
1998	143,381,600	145,004,214	1.1%
1999	152,311,035	158,211,646	3.9%
2000	156,667,497	161,051,779	2.8%
2001	165,931,549	164,655,659	-0.8%
2002	176,920,133	174,825,155	-1.2%
2003	174,477,589	172,577,753	-1.1%
2004	178,152,405	172,657,905	-3.1%
2005	188,569,914	186,725,048	-1.0%
2006	182,453,427	184,179,306	0.9%
2007	188,506,590	190,786,244	1.2%
2008		193,671,387	
2009		197,857,361	

Please note that further adjustments are made to the modeled forecasts for 2008 and 2009 to reflect the impact of a plant closure and CDM, as outlined below in this Schedule.

Impact of Plant Closure

The impact of major events affecting kWh purchases which emerge in 2008 cannot be modeled using regression analysis of historic data prior to 2008. However, without reflecting such impacts, the forecasts for 2008 and 2009 would be overstated. Therefore, adjustments to the regression-modeled amounts for 2008 and 2009 were made to obtain adjusted weather normalized forecasts which recognize such an event occurring in NOTL Hydro’s customer base.

During the development of this application, it became known that NOTL Hydro’s largest customer in terms of kWh consumption was to cease operation in mid-2008. The customer (Cangro) was a fruit-processing plant in the village of St. Davids in Niagara-on-the-Lake. Cangro was in the GS >50kW customer class. Because the historic data used for the regression included this major customer, an adjustment to the modeled purchases for 2008 and 2009 was required to reflect its absence. No replacement customer data, if any, is known at present.

The following table provides the available historic consumption data for the 4 sites of the Cangro customer: The full-year adjustment affecting 2009 and the part-year adjustment for 2008 are shown, calculated as the average 8-year billed kWh consumption adjusted for the loss factor requested in this application.

Table 7

Former Cangro Customer Consumption

All Sites	Total kWh	kW	# of Sites
2007 Totals	5,333,460	15,007	4
2006 Totals	5,760,960	14,721	4
2005 Totals	5,978,820	16,309	4
2004 Totals	5,618,520	15,001	4
2003 Totals	4,490,120	12,757	4
2002 Totals	4,632,000	13,258	4
2001 Totals	4,437,180	11,775	4
2000 Totals	4,792,440	11,943	4
AVERAGE	5,130,438		

8-YEAR AVERAGE			**# of Sites**
Consumption	5,130,438	kWh	4
Loss Factor	1.0501		
Annual Purchases	5,387,472	kWh	
Part Year (2008)	2,693,736	kWh	:

The model calculations adjusted for Cangro for 2008 and 2009 are as follows:

Table 8

Adjustment for Loss of Cangro Customer

Year	Modelled kWh	Cangro Adjustment	Adjusted Calculation
2008	193,671,387	-2,693,736	190,977,651
2009	197,857,361	-5,387,472	192,469,889

CDM/Energy Conservation

NOTL Hydro wishes to include consideration of energy conservation resulting from conservation and demand management (CDM) activities, either local initiatives or the Ontario Power Authority’s province wide programs. As indicated by the OEB in decisions on 2008 rate rebasing applications, the fact that inclusion of the impact of these measures has the effect of placing an upward pressure on rates does not negate or lessen NOTL Hydro’s responsibility to consider this impact.

NOTL Hydro proposes to apply a 0.34% reduction to the 2008 and 2009 adjusted calculations of purchases tabulated above, to reflect the impact of the successful NOTL Hydro 3rd tranche CDM programs. This percentage is based on the results of the application of the OEB-endorsed Total Resource Cost (TRC) model for NOTL Hydro CDM programs. These results were included NOTL Hydro's 2007 Annual CDM Report to the OEB, which reported a reduction in total customer consumption of 610,161 kWh, which represents approx. 0.34% of the 2007 billed kWh of 180,475,098 kWh .

The resulting weather normalized forecast kWh purchases are as follows:

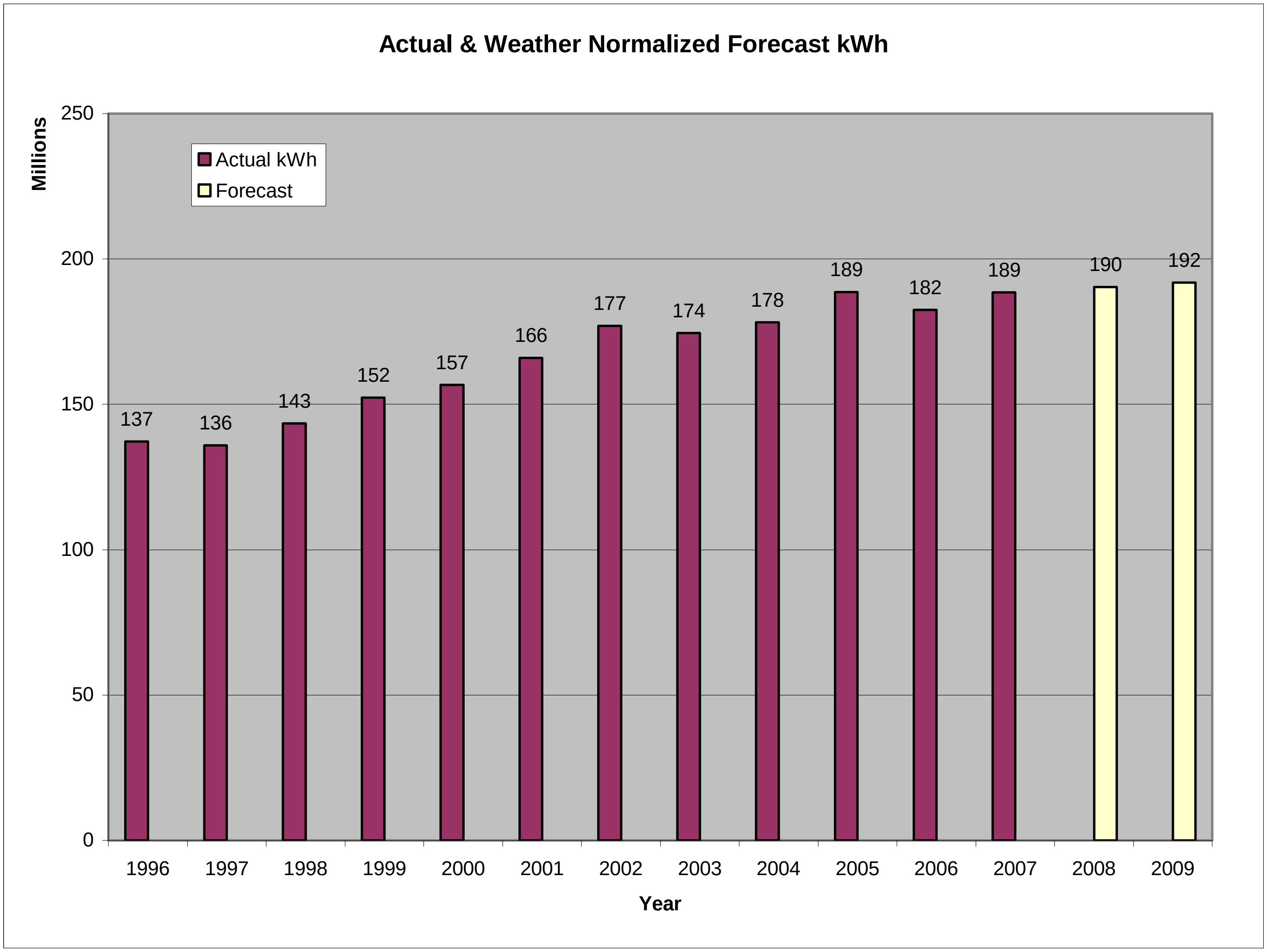
Table 9

Adjustment for CDM

Year	Cangro-Adjusted Calculation kWh	CDM Reduction	Weather Normalized Forecast Purchases kWh
2008	190,977,651	-649,324	190,328,327
2009	192,469,889	-654,398	191,815,491
		-0.34%	

Incorporating the adjustments for the Cangro closure and CDM for 2008 and 2009, the chart below compares the actual annual purchases from 1996 to 2007 with the weather normalized forecast kWh purchases for 2008 and 2009 used for this rate application.

Actual and Weather Normalized Forecast Purchases



Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by the OEB approved loss factor of

1.0501, which has been in effect since May 1, 2006 and is proposed to remain unchanged for 2008 and 2009. The resulting weather normalized energy billed forecasts are as follows:

Table 10

Billed kWh Forecast

Year	Weather Normalized Purchases kWh	Loss Adjustment	Weather Normalized Billed kWh
2008	190,328,327	-9,080,515	181,247,811
2009	191,815,491	-9,151,468	182,664,024

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available for the past 6 years, 2002 to 2007, as shown in the following table, together with knowledge of future local development, short term economic projections and other factors affecting customer/connection counts.

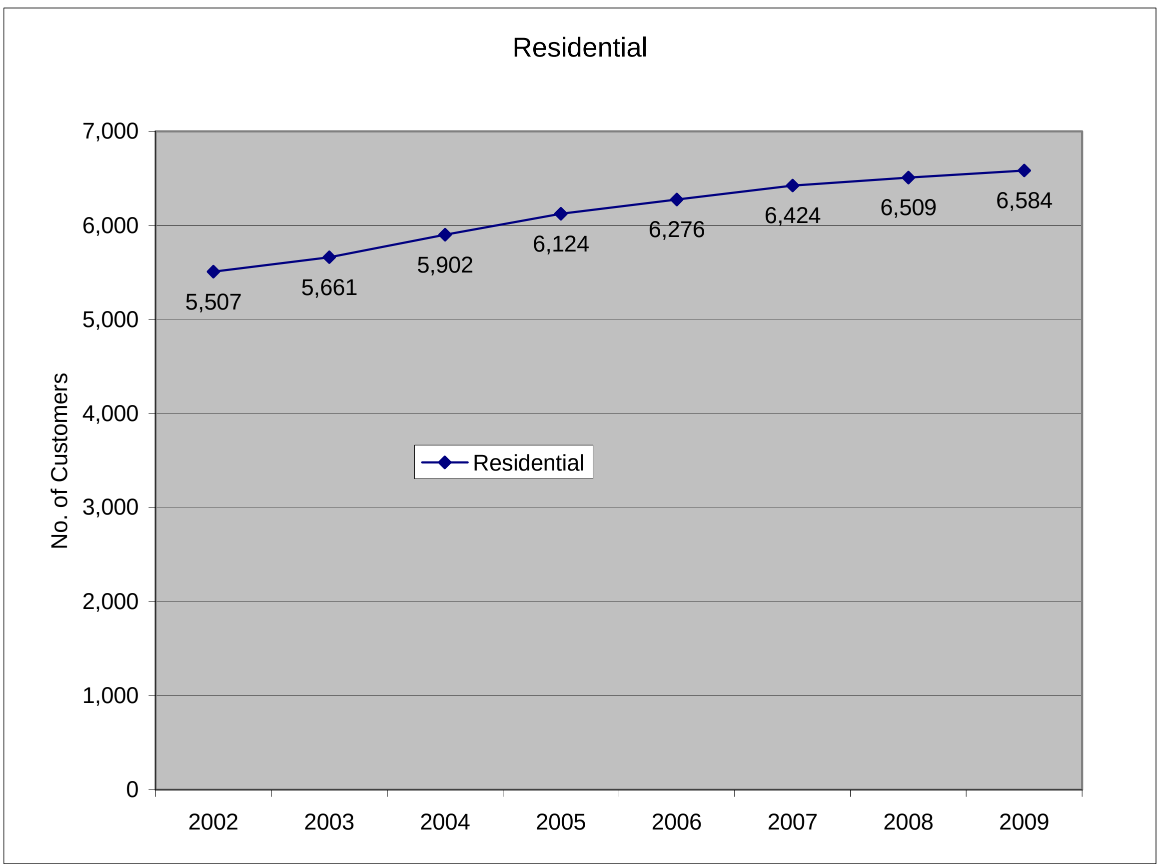
Table 11
Historical Customer/Connection Data

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load	Total
Number of Customers/Connections							
2002	5,507	1,234	89	1,483	110	24	8,447
2003	5,661	1,230	95	1,591	108	24	8,709
2004	5,902	1,227	98	1,611	105	24	8,967
2005	6,124	1,210	108	1,658	80	24	9,204
2006	6,276	1,209	117	1,736	77	24	9,439
2007	6,424	1,216	115	1,796	76	23	9,650
Geomean Annual Growth Rate	1.0313	0.9971	1.0526	1.0390			

Residential

For the residential class, an examination of known and expected lot developments in Niagara-on-the-Lake, combined with short term economic and growth projections, was done to determine the forecast customer counts for 2008 and 2009. An additional 85 customers are expected in 2008 and a further 75 in 2009. In 2009, approx. 50 customers are expected to transfer to St. Catharines (Horizon Utilities) as part of the resolution of load transfers. The resulting forecasts are 6,509 customers in 2008 and 6,584 customers in 2009. Application of the geometric mean growth rate is considered to over-estimate the customer count in 2008 and 2009.

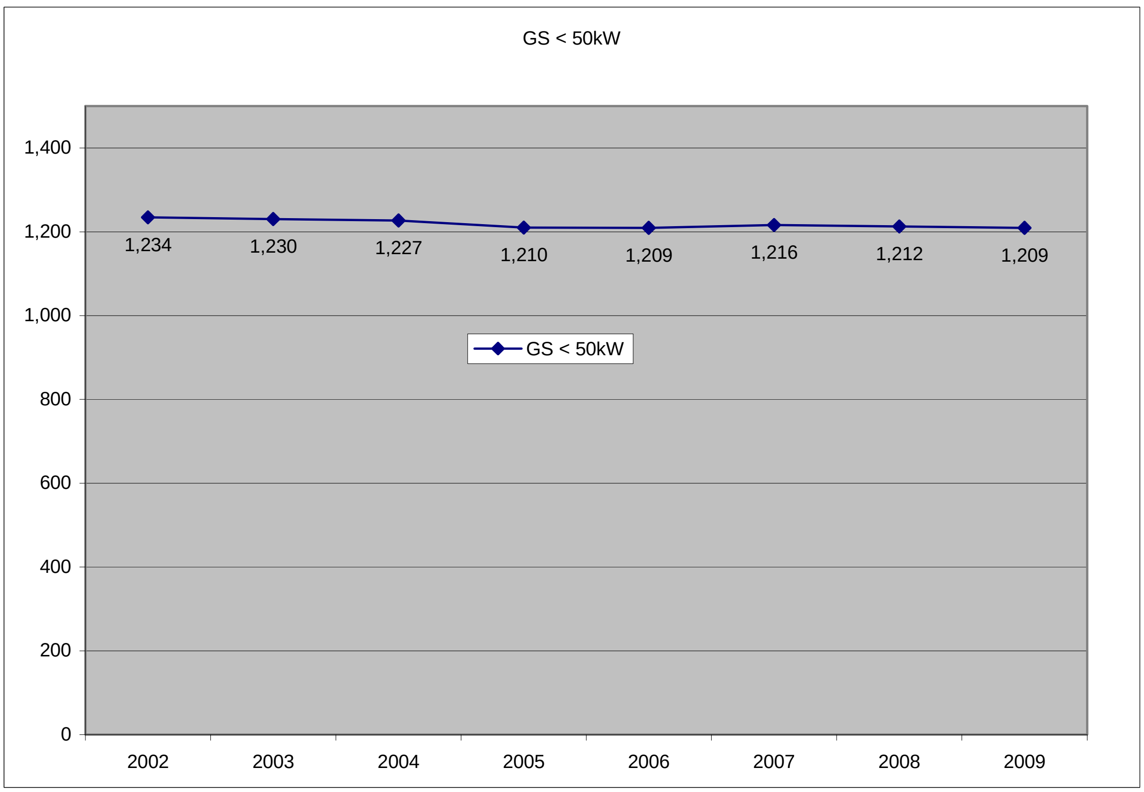
The chart below shows the resulting residential customer counts for the period 2002 to 2009:



GS <50kW

For the GS <50kW class, the geometric mean growth rate for the period 2002 to 2007 is considered to be appropriate as an estimator of the customer counts for 2008 and 2009. The resulting forecasts are a small reduction in customers in this class, to 1,212 in 2008 and 1,209 in 2009.

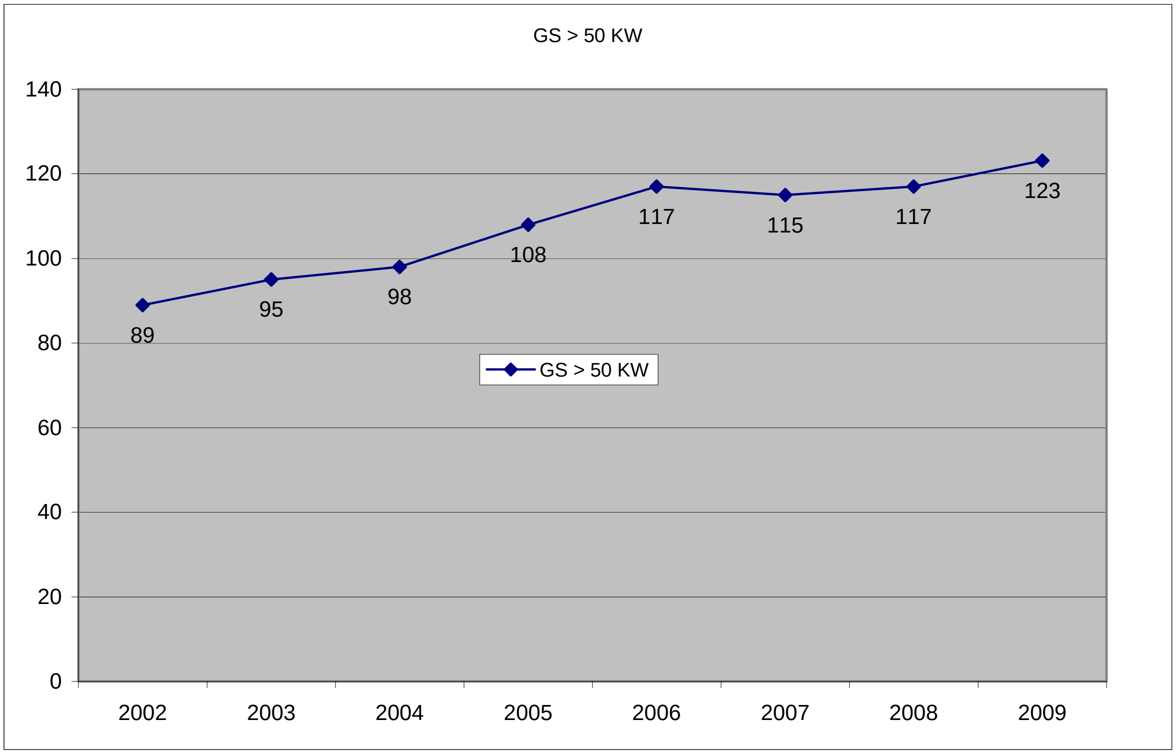
The chart below shows the resulting GS <50kW customer counts for the period 2002 to 2009:



GS > 50kW

For the GS >50kW class, the geometric mean growth rate for the period 2002 to 2007 is considered to be appropriate as an estimator of the customer counts for 2008 and 2009, together with a reduction of 4 related to the closure of the Cangro customer sites. The resulting forecasts are 117 customers in 2008 and 123 customers in 2009.

The chart below shows the resulting GS >50kW customer counts for the period 2002 to 2009:



Sentinel Lights

For the sentinel lights class, NOTL Hydro is proposing to eliminate this class in 2009. In 2008, 25 of the existing 76 sentinel lights from 2007 will be converted to 9 unmetered load class customers and 14 lights will be converted to Town of Niagara-on-the-Lake streetlights. The remaining sentinel lights will disconnected from the NOTL Hydro system in 2009 (and may be rewired to the customer supply). The resulting forecasts are 37 connections in 2008 and nil in 2009.

Streetlights

For the streetlights class, the geometric mean growth rate for the period 2002 to 2007 is considered to be appropriate as an estimator of the customer counts for 2008 and 2009, together with the increase of 9 mentioned above regarding conversion of sentinel lights. The resulting forecasts are 1,880 connections in 2008 and 1,953 in 2009.

Unmetered Scattered Load

For the unmetered scattered load class, an additional 9 customers are added in 2008 to reflect the conversion from sentinel lights mentioned above. The resulting forecasts are 32 customers in 2008 and 32 in 2009.

In summary, the forecast customer/connection count forecasts are as follows:

Table 12
Customer/Connection Forecast

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load	Total
Forecast Number of Customers/Connections							
2008	6,509	1,212	117	1,880	37	32	9,787
2009	6,584	1,209	123	1,953	0	32	9,901

This data was also contained in Table 2 earlier in this Schedule.

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer/connection by rate class for the past 5 years, 2003 to 2007, for which data is available.

Table 13
Annual Average Usage per Customer/Connection

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load
Energy usage per customer/connection (kWh per customer/connection)						
2003	10,506	28,464	742,518	556	1,345	9,080
2004	10,190	27,995	754,761	568	1,881	9,080
2005	11,102	28,495	705,219	601	1,523	9,080
2006	10,208	25,209	677,408	645	1,608	9,080
2007	10,196	28,758	684,216	558	1,329	9,475

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed which is provided on the following table. The geometric mean growth rate has also been shown.

Table 14
Growth Rate in Usage Per Customer/Connection

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load
Annual growth rate in usage per customer/connection						
2003						
2004	-3.0%	-1.6%	1.6%	2.1%	39.8%	0.0%
2005	9.0%	1.8%	-6.6%	5.8%	-19.0%	0.0%
2006	-8.1%	-11.5%	-3.9%	7.3%	5.6%	0.0%
2007	-0.1%	14.1%	1.0%	-13.4%	-17.4%	4.3%
Geometric Mean	-0.7%	0.3%	-2.0%	0.1%	-0.3%	1.1%

A review of the 5-year data and the resulting geometric means did not suggest a consistent pattern that should be projected to 2008 and 2009. Therefore, for the purposes of determining a non-normalized forecast, the 2007 usage per customer/connection was held constant for 2008 and 2009, except for an adjustment for the GS >50kW class to reflect the Cangro closure. The forecasted usage by rate class is as follows

Table 15
Forecast Annual kWh Non-Normalized Usage per Customer/Connection

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load
Forecast Annual Non-normalized kWh usage per customer/connection						
2008	10,196	28,758	660,824	558	1,329	9,475
2009	10,196	28,758	660,824	558	n/a	9,475

With the preceding information, the non-normalized weather billed energy forecast can be determined by applying the forecast number of customer/connection from Table 12 by the forecast of annual usage per customer/connection from Table 15. The resulting non-normalized weather billed energy forecast is shown in the following table (numbers calculated may not appear to be exact due to rounding):

Table 16
Non-normalized Weather Billed Energy Forecast

Year	Residential	GS < 50kW	GS > 50kW	Street Lights	Sentinel Lights	Unmetered Load
Forecast Annual Non-normalized kWh usage						
2008	66,365,764	34,867,109	80,069,864	1,049,040	49,173	303,200
2009	67,130,464	34,768,422	81,382,914	1,089,774	0	303,200

The non-normalized weather billed energy forecast has been determined as above, but needs to be adjusted for weather sensitive load and for CDM in order to be aligned with the total weather normalized billed energy forecast. The following table outlines the alignment calculation of the weather-normalized billed energy forecasts for 2008 and 2009:

Table 17

Alignment of Non-Normalized to Weather-Normalized Billed Energy Forecasts

Year 2008	Non-Normalized Billed Energy Forecast	Weather Sensitive %	Weather Sensitive Energy	Weather Adjustment	Weather-Adjusted	CDM Adjustment	Weather Normalized Billed Forecast
Residential	66,365,764	100%	66,365,764	-356,952	66,008,812	-0.34%	65,784,382
GS <50 kW	34,867,109	100%	34,867,109	-187,535	34,679,574	-0.34%	34,561,664
GS >50kW	80,069,864	68%	54,569,691	-293,506	79,776,357	-0.34%	79,505,118
Sentinel Lights	49,173	0%	0	0	49,173	-0.34%	49,006
Street Lights	1,049,040	0%	0	0	1,049,040	-0.34%	1,045,473
Unmetered Load	303,200	0%	0	0	303,200	-0.34%	302,169
TOTAL	182,704,150		155,802,564	-837,993	181,866,156		181,247,811

Year 2009	Non-Normalized Billed Energy Forecast	Weather Sensitive %	Weather Sensitive Energy	Weather Adjustment	Weather-Adjusted	CDM Adjustment	Weather Normalized Billed Forecast
Residential	67,130,464	100%	67,130,464	-583,375	66,547,089	-0.34%	66,320,829
GS <50 kW	34,768,422	100%	34,768,422	-302,143	34,466,279	-0.34%	34,349,093
GS >50kW	81,382,914	71%	57,772,807	-502,055	80,880,859	-0.34%	80,605,864
Sentinel Lights	0	0%	0	0	0	-0.34%	0
Street Lights	1,089,774	0%	0	0	1,089,774	-0.34%	1,086,069
Unmetered Load	303,200	0%	0	0	303,200	-0.34%	302,169
TOTAL	184,674,774		159,671,693	-1,387,574	183,287,200		182,664,024

In these calculation tables, the total weather adjusted billed energy forecast prior to CDM adjustment is 181,866,156 kWh for 2008 and 183,287,200 kWh for 2009. The differences between these values and the non-normalized and normalized forecast are -837,993 kWh in 2008 and -1,387,574 kWh in 2009. These differences are assigned to those rate classes that are weather sensitive.

As determined in the weather normalization work completed by Hydro One for NOTL Hydro in the 2006 cost allocation review, the residential and GS <50kW classes are considered to be 100% weather sensitive, and the sentinel lights, street lights and unmetered scattered load classes are considered to be 0% weather sensitive. NOTL Hydro determined the weather sensitivity of the GS >50kW class for this application by assessing each customer in this class individually as to whether or not it is weather sensitive. Using 2007 actual billed kWh for these customers as a measure, the consumption of weather sensitive customers in this class in 2008 is estimated to be 68% of the total kWh for this class and 71% of the total in 2009. The increase in the percentage from 2008 to 2009 is due to the Cangro closure mentioned previously. Cangro was considered to be non-weather sensitive, thus the proportion that is weather sensitive increases when Cangro consumption is omitted. The weather adjustment differences have been assigned on a prorate basis to each rate class based on the above levels of weather sensitivity. Finally, in line with the CDM adjustment to the forecast purchases, a corresponding CDM adjustment is made to the billed kWh data.

Billed KW Load Forecast

There are a number of rate classes that charge volumetric distribution on per kW basis. These include General Service > 50 kW, Streetlights and Sentinel Lights. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class for the years that data is available (i.e. 2002 to 2007) and the average for the period. Cangro customer data is excluded to ensure an appropriate calculation for 2008 and 2009 forecast kW.

Table 18
Historical Annual kW per Applicable Rate Class

kW	GS >50kW	Street Lights	Sentinel Lights
Year			
2003	177,667	2,380	422
2004	184,831	2,577	401
2005	167,126	2,626	337
2006	186,383	2,644	251
2007	188,388	2,899	257
Average	180,879	2,625	334

The following is the corresponding data for kWh:

Table 19
Historical Annual KWh per Applicable Rate Class

kWh	GS >50kW	Street Lights	Sentinel Lights
Year			
2003	66,049,106	884,324	145,274
2004	68,348,030	914,682	197,474
2005	70,184,862	995,698	121,803
2006	73,495,752	1,118,911	123,814
2007	73,351,436	1,002,185	100,974
Average	70,285,837	983,160	137,868

The following is the ratio of kW/kWh data:

Table 20
Historical kW/kWh Ratio per Applicable Rate Class

kW/kWh Ratio	GS >50kW	Street Lights	Sentinel Lights
Year			
2003	0.2690%	0.2691%	0.2907%
2004	0.2704%	0.2817%	0.2031%
2005	0.2381%	0.2637%	0.2767%
2006	0.2536%	0.2363%	0.2027%
2007	0.2568%	0.2893%	0.2545%
Average	0.2573%	0.2670%	0.2420%

The following outlines the forecast of kW for the applicable rate classes using the average kW/kWh ratio in the above table:

Table 21
kW Forecast by Applicable Rate Class

kW Forecast	GS >50kW	Street Lights	Sentinel Lights
2008	204,605	2,791	119
2009	207,437	2,900	0

Summary

The following table summarizes the consumption and customer/connections data for each rate class as approved for 2006, actual 2006 and 2007, and weather normalized 2008 bridge year and 2009 test year.

Table 22
Summary of Forecast Data

Niagara-on-the-Lake Hydro Inc.		Historical Board Approved From 2006 EDR	Historical Actual	Historical Actual	Bridge Year Estimate Normalized	Test Year Normalized Forecast
Year		2004	2006	2007	2008	2009
Customer Class						
Residential	Customers	5,902	6,276	6,424	6,509	6,584
	Consumption - kWh	63,617,729	64,063,446	65,499,951	65,784,382	66,320,829
GS < 50 kW	Customers	1,233	1,209	1,216	1,212	1,209
	Consumption - kWh	35,862,790	30,478,041	34,969,161	34,561,664	34,349,093
GS >50	Customers	98	117	115	117	123
	Consumption - kWh	72,785,865	79,256,712	78,684,896	79,505,118	80,605,864
	Demand - KW	205,820	201,104	203,395	204,605	207,437
Sentinel Lights	Connections	105	77	76	37	0
	Consumption - kWh	155,150	123,814	100,974	49,006	0
	Demand - KW	362	251	257	119	0
Street Lighting	Connections	1,611	1,736	1,796	1,880	1,953
	Consumption - kWh	860,329	1,118,911	1,002,185	1,045,473	1,086,069
	Demand - KW	2,176	2,644	2,899	2,791	2,900
USL	Customers	24	24	23	32	32
	Consumption - kWh	217,931	217,931	217,931	302,169	302,169

OTHER DISTRIBUTION REVENUE:

Table 1 summarizes NOTL Hydro’s other revenues, included in NOTL Hydro’s total revenue requirement.

Table 1
Other Distribution Revenues

Description of Other Revenue	2006 OEB Approved	2006 Actual	Variance from 2006 Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual	2009 Test Year	Variance from 2008 Bridge
4080-SSS Admin	26,103	27,839	1,736	26,771	-1,067	29,362	2,591	29,703	341
4082-Retail Services Revenues	1,714	3,732	2,018	7,506	3,774	7,286	-220	7,286	0
4084-Service Transaction Requests (STR) Revenues	68	369	301	202	-167	218	16	218	0
4090-Electric Services Incidental to Energy Sales	33,522	112,430	78,909	0	-112,430	0	0	0	0
4210-Rent from Electric Property	52,720	69,027	16,307	70,743	1,716	70,000	-743	70,000	0
4225-Late Payment Charges	7,130	1,084	-6,046	50,452	49,368	48,070	-2,382	48,070	0
4235-Miscellaneous Service Revenues	46,492	49,282	2,791	48,700	-583	45,430	-3,270	45,430	0
4315-Revenues from electric plant leased to others	0	1,000	1,000	0	-1,000	0	0	0	0
4325-Revenues from Merchandise, Jobbing, Etc.	75,956	74,781	-1,175	59,028	-15,753	60,000	972	60,000	0
4335-Profits and Losses from Financial Instrument Hedges	0	0	0	33,911	33,911	34,000	89	34,000	0
4350/60-Gains/Losses from Disposition of Future Use Utility Plant	-18,635	14,849	33,484	-26,005	-40,854	-10,000	16,005	0	10,000
4390-Miscellaneous Non-Operating Income	8,707	20,487	11,780	17,105	-3,382	15,000	-2,105	15,000	0
4405-Interest and Dividend Income	14,409	78,426	64,017	32,436	-45,990	41,472	9,036	51,915	10,443
Totals	248,184	453,306	205,122	320,848	-132,457	340,839	19,990	361,622	20,784

The data in Table 1 above provides the breakdown of the “Total Other Revenue” line in Table 1 in **Exhibit 3, Tab 1, Schedule 2**.

OTHER DISTRIBUTION REVENUE – VARIANCE ANALYSIS:

Variances in Other Distribution Revenue were explained in **Exhibit 3, Tab 2, Schedule 1.**

RATE OF RETURN ON OTHER DISTRIBUTION REVENUE:

In rate application, NOTL Hydro is applying for the same specific service charges as previously approved by the Board in the 2008 Tariffs of Rates and Charges.

Except for funds received from the OPA for 2008 CDM programming, which included a 10 per cent program administration fee, other distribution revenues do not include a rate of return.

DESCRIPTION OF REVENUE SHARING:

NOTL Hydro does not have a revenue sharing practice in place.

INDEX FOR EXHIBIT 4

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OVERVIEW OF OPERATING COSTS:

Operating Costs:

The operating costs presented in this Exhibit represent the annual expenditures required to sustain NOTL Hydro distribution operations. NOTL Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance.

The first category includes Operation, Maintenance & Administration (OM&A) and other Costs which includes taxes other than income tax and amortization (depreciation) expenses. The amortization rates outlined in Appendix B of the 2006 Rate Book were used in this application to determine amortization expense. In addition, this category addresses the Loss Adjustment Factor.

The second category includes Income Tax and Ontario Capital Taxes.

Exhibit 4, Tab 1, Schedule 2 provides summaries of NOTL Hydro's Operating Costs and income taxes for the historical, bridge and test years.

Detailed information with respect to OM&A costs and variances is provided in **Exhibit 4, Tab 2, Schedules 1, 2 and 3.**

OM&A Costs:

OM&A costs in this Exhibit represent NOTL Hydro's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to NOTL Hydro's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A expenditures for the 2009 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

NOTL Hydro is proposing recovery of 2009 Test Year OM&A costs, including amortization and taxes other than income taxes, totaling $3,143,296.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

NOTL Hydro is proposing recovery of 2009 Test Year taxes totaling $426,198. Details of this amount are shown in **Exhibit 4, Tab 1, Schedule 2**.

OM&A Budgeting Process Used by NOTL Hydro:

Operating budgets are prepared annually by management and are reviewed and approved by the Board of Directors. A preliminary budget is prepared in the fall and presented to the Board for comment and direction. The final budget is prepared in line with the Board's direction and approved by the Board before the start of each fiscal year. Once approved, it does not change, but provides a plan against which actual results may be evaluated. The 2008 bridge year forecast is based on the 2008 approved budget with adjustments to reflect more up-to-date information where known and appropriate. The development of the 2009 test year forecast followed a similar budget process with approval by the Board, but was accelerated to comply with the late summer due date (August 7) of this application.

Each of the two senior managers (Director of Corporate Services and Operations Manager) is responsible for the preparation of their own departmental budgets and for input of the results into the overall corporate budget computer model. The Director of Corporate Services coordinates the corporate budget model and review of the budget, initially by the senior management team as a whole, chaired by the President, and then by the Board.

Payroll costs are developed employee by employee, by assessing the hours that the employee will spend on each operating activity and reflecting the applicable rate of pay of the employee, regular progressions, merit increases and the employee benefits applicable. Wage rate increases as per the Collective Agreement with the union are respected.

Non-payroll costs are developed item by item. For items where a normal inflationary pressure on operating costs needed to be reflected in the 2009 test year budget for this rate application, the input price index of 1.9% as used in the 2007 IRM applications was used.

Summary of Operating Costs Table:

A summary of NOTL Hydro's operating costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements, is provided in Table 1 below.

Table 1
Summary of Operating Costs

Summary of Operating Costs

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
OM&A expenses					
Operation	323,382	260,994	342,844	377,390	373,710
Maintenance	304,410	388,961	431,315	474,671	521,359
Billing and Collections	270,862	310,202	355,606	312,374	318,798
Community Relations	713	29,210	8,783	1,000	1,020
Administrative and General Expenses	582,047	557,582	580,205	589,054	649,774
Taxes Other Than Income Taxes	139,754	30,833	33,846	33,800	33,450
Amortization Expenses	1,085,204	1,247,363	1,241,397	1,212,708	1,245,184
Total Operating Costs	2,706,371	2,825,144	2,993,997	3,000,997	3,143,296
Determination of Variance Amount (1%)	27,064	28,251	29,940	30,010	31,433

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

NOTL Hydro is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Table 2 below provides a summary of 2006 OEB Approved, 2008 Bridge and 2009 Test Year income taxes.

Table 2
Summary of Income Taxes

Summary of Income Taxes

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Income Taxes	292,722	468,793	211,742	382,784	411,031
Large Corporation Tax	0	0	0	0	0
Ontario Capital Tax	29,296	30,000	24,997	18,882	15,166
Total Taxes	322,017	498,793	236,739	401,666	426,198

OM&A Costs Table:

The Table below provides details of NOTL Hydro OM&A costs for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year including the determination of the variance amount for analysis, in accordance with the Filing Requirements.

OM&A Cost Table

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Operations									
5005-Operation Supervision and Engineering	44,301	56,039	11,738	84,554	28,516	92,298	7,743	90,580	(1,718)
5010-Load Dispatching	7,057	2,072	(4,985)	0	(2,072)	30,679	30,679	30,683	4
5012-Station Buildings and Fixtures Expense	0	0	0	0	0	0	0	0	0
5014-Transformer Station Equipment - Operation Labour	7,207	0	(7,207)	0	0	5,396	5,396	5,361	(36)
5015-Transformer Station Equipment - Operation Supplies and Expenses	29,957	1,735	(28,222)	(13,379)	(15,114)	12,950	26,329	13,250	300
5016-Distribution Station Equipment - Operation Labour	705	0	(705)	0	0	5,100	5,100	6,100	1,000
5017-Distribution Station Equipment - Operation Supplies and Expenses	0	0	0	0	0	0	0	0	0
5020-Overhead Distribution Lines and Feeders - Operation Labour	19,626	26,067	6,441	37,316	11,248	23,472	(13,844)	26,692	3,221
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	24,489	24,216	(272)	45,631	21,415	22,484	(23,148)	24,920	2,437
5030-Overhead Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0
5035-Overhead Distribution Transformers- Operation	1,454	25,404	23,951	14,615	(10,790)	2,627	(11,988)	2,628	1
5040-Underground Distribution Lines and Feeders - Operation Labour	20,354	5,797	(14,557)	6,459	662	15,814	9,355	18,860	3,046
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	39,343	35,176	(4,167)	20,321	(14,855)	4,338	(15,983)	5,341	1,003
5050-Underground Subtransmission Feeders - Operation	0	0	0	0	0	0	0	0	0
5055-Underground Distribution Transformers - Operation	2,918	3,035	117	14,963	11,928	2,837	(12,126)	2,882	45
5060-Street Lighting and Signal System Expense	0	0	0	0	0	0	0	0	0
5065-Meter Expense	48,842	11,328	(37,514)	18,460	7,132	10,619	(7,842)	13,278	2,660
5070-Customer Premises - Operation Labour	8,177	7,934	(243)	8,307	373	9,458	1,151	7,986	(1,472)
5075-Customer Premises - Materials and Expenses	1,698	1,479	(219)	18,912	17,433	37,063	18,151	40,076	3,012
5085-Miscellaneous Distribution Expense	49,195	42,357	(6,838)	67,253	24,896	83,456	16,203	66,273	(17,184)
5090-Underground Distribution Lines and Feeders - Rental Paid	18,059	0	0	0	0	0	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	18,354	18,354	19,432	1,077	18,800	(632)	18,800	0
5096-Other Rent	0	0	0	0	0	0	0	0	0
Sub-Total	**323,382**	**260,994**	**(44,329)**	**342,844**	**81,850**	**377,390**	**34,546**	**373,710**	**(3,680)**

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Maintenance									
5105-Maintenance Supervision and Engineering	31,414	42,122	10,708	52,255	10,132	79,928	27,674	79,394	(535)
5110-Maintenance of Buildings and Fixtures - Distribution Stations	0	0	0	0	0	0	0	0	0
5112-Maintenance of Transformer Station Equipment	3,886	51,585	0	49,015	(2,570)	13,263	(35,752)	20,785	7,522
5114-Maintenance of Distribution Station Equipment	15,044	7,019	(8,025)	13,252	6,233	4,755	(8,497)	5,272	516
5120-Maintenance of Poles, Towers and Fixtures	18,937	29,764	10,828	34,176	4,412	33,716	(460)	33,590	(126)
5125-Maintenance of Overhead Conductors and Devices	63,584	36,832	(26,753)	49,098	12,267	53,206	4,107	52,567	(639)
5130-Maintenance of Overhead Services	12,466	31,251	18,784	30,898	(353)	57,505	26,607	57,774	270
5135-Overhead Distribution Lines and Feeders - Right of Way	88,259	73,354	(14,905)	78,246	4,892	77,683	(563)	92,564	14,881
5145-Maintenance of Underground Conduit	47	902	855	2,794	1,892	1,100	(1,694)	1,100	0
5150-Maintenance of Underground Conductors and Devices	21,526	10,581	(10,945)	9,782	(799)	20,050	10,268	20,087	37
5155-Maintenance of Underground Services	14,450	28,028	13,579	73,310	45,282	53,205	(20,105)	53,253	48
5160-Maintenance of Line Transformers	30,518	65,473	34,955	20,554	(44,919)	62,941	42,387	88,680	25,739
5165-Maintenance of Street Lighting and Signal Systems	0	0	0	0	0	0	0	0	0
5170-Sentinel Lights - Labour	0	0	0	0	0	0	0	0	0
5172-Sentinel Lights - Materials and Expenses	0	0	0	0	0	0	0	0	0
5175-Maintenance of Meters	4,279	12,049	7,770	17,936	5,887	17,321	(615)	16,294	(1,026)
5178-Customer Installations Expenses-Leased Property	0	0	0	0	0	0	0	0	0
5185-Water Heater Rentals - Labour	0	0	0	0	0	0	0	0	0
5186-Water Heater Rentals - Materials and Expenses	0	0	0	0	0	0	0	0	0
5190-Water Heater Controls - Labour	0	0	0	0	0	0	0	0	0
5192-Water Heater Controls - Materials and Expenses	0	0	0	0	0	0	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0	0	0	0	0	0	0
Sub-Total	**304,410**	**388,961**	**36,851**	**431,315**	**42,355**	**474,671**	**43,356**	**521,359**	**46,688**

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Billing and Collections									
5305-Supervision	13,407	3,028	(10,380)	10,399	7,371	12,861	2,462	13,530	670
5310-Meter Reading Expense	32,437	42,678	10,241	43,191	513	48,609	5,418	49,768	1,159
5315-Customer Billing	151,276	148,578	(2,699)	153,382	4,805	156,687	3,305	159,131	2,444
5320-Collecting	47,435	78,207	30,772	103,092	24,885	74,218	(28,874)	76,368	2,150
5325-Collecting- Cash Over and Short	(7)	(235)	0	19	254	0	(19)	0	0
5330-Collection Charges	0	0	0	0	0	0	0	0	0
5335-Bad Debt Expense	26,313	37,947	11,634	45,524	7,577	20,000	(25,524)	20,000	0
5340-Miscellaneous Customer Accounts Expenses	0	0	0	0	0	0	0	0	0
Sub-Total	**270,862**	**310,202**	**39,568**	**355,606**	**45,405**	**312,374**	**(43,232)**	**318,798**	**6,423**
Community Relations									
5405-Supervision	0	0	0	0	0	0	0	0	0
5410-Community Relations - Sundry	0	0	0	0	0	0	0	0	0
5415-Energy Conservation	0	29,210	29,210	8,136	(21,074)	0	(8,136)	0	0
5420-Community Safety Program	0	0	0	0	0	0	0	0	0
5425-Miscellaneous Customer Service and Informational Expenses	713	0	0	648	648	1,000	352	1,020	20
5505-Supervision	0	0	0	0	0	0	0	0	0
5510-Demonstrating and Selling Expense	0	0	0	0	0	0	0	0	0
5515-Advertising Expense	0	0	0	0	0	0	0	0	0
5520-Miscellaneous Sales Expense	0	0	0	0	0	0	0	0	0
Sub-Total	**713**	**29,210**	**29,210**	**8,783**	**(20,426)**	**1,000**	**(7,783)**	**1,020**	**20**

Expense Description	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2007 Actual	Variance from 2006 Actual	2008 Bridge	Variance from 2007 Actual	2009 Test	Variance from 2008 Bridge
Administrative and General Expenses									
5605-Executive Salaries and Expenses	51,844	55,508	3,663	60,293	4,785	63,826	3,533	67,260	3,434
5610-Management Salaries and Expenses	76,362	87,561	11,199	81,922	(5,639)	93,875	11,953	98,680	4,805
5615-General Administrative Salaries and Expenses	82,979	77,922	(5,057)	87,665	9,744	112,536	24,871	115,449	2,913
5620-Office Supplies and Expenses	40,445	24,011	(16,435)	46,801	22,790	25,510	(21,291)	25,430	(80)
5625-Administrative Expense Transferred Credit	0	0	0	0	0	0	0	0	0
5630-Outside Services Employed	25,070	38,545	13,475	33,645	(4,900)	28,500	(5,145)	67,283	38,783
5635-Property Insurance	22,600	23,223	623	23,982	758	21,000	(2,982)	20,600	(400)
5640-Injuries and Damages	29,921	24,278	(5,644)	27,509	3,231	28,000	491	27,700	(300)
5645-Employee Pensions and Benefits	78,275	23,967	(54,308)	19,471	(4,497)	22,000	2,529	22,000	0
5650-Franchise Requirements	0	0	0	0	0	0	0	0	0
5655-Regulatory Expenses	29,321	30,799	1,478	31,043	244	22,630	(8,413)	25,475	2,845
5660-General Advertising Expenses	7,843	1,907	(5,936)	1,500	(407)	1,000	(500)	1,020	20
5665-Miscellaneous General Expenses	78,060	93,193	15,132	73,908	(19,284)	50,000	(23,908)	50,450	450
5670-Rent	0	0	0	0	0	0	0	0	0
5675-Maintenance of General Plant	59,325	76,168	16,843	87,849	11,681	114,807	26,958	123,057	8,250
5680-Electrical Safety Authority Fees	0	0	0	4,367	4,367	5,370	1,003	5,370	0
5685-Independent Market Operator Fees and Penalties	0	0	0	0	0	0	0	0	0
6205-Charitable Donations	0	500		250	(250)	0	(250)	0	0
Sub-Total	**582,047**	**557,582**	**(24,965)**	**580,205**	**22,623**	**589,054**	**8,849**	**649,774**	**60,720**
Taxes Other Than Income Taxes									
6105-Property Taxes	28,903	30,833	1,931	33,846	3,013	33,800	(46)	33,450	(350)
Sub-Total	**28,903**	**30,833**	**1,931**	**33,846**	**3,013**	**33,800**	**(46)**	**33,450**	**(350)**
Total Operating, Maintenance and Administration Expenses	**1,510,316**	**1,577,781**	**38,266**	**1,752,600**	**174,819**	**1,788,290**	**35,689**	**1,898,111**	**109,821**
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	1,085,204	1,247,363	162,159	1,241,397	(5,966)	1,212,708	(28,689)	1,245,184	32,477
Sub-Total	**1,085,204**	**1,247,363**	**162,159**	**1,241,397**	**(5,966)**	**1,212,708**	**(28,689)**	**1,245,184**	**32,477**
Total Distribution Expense Before Income Ta	2,595,520	2,825,144		2,993,997		3,000,997		3,143,296	
Variance Determined as 1% of Total Distributi	25,955	28,251		29,940		30,010		31,433	
Materiality		**28,251**		**29,940**		**30,010**		**31,433**	

ANALYSIS OF MATERIAL VARIANCES IN OM&A COSTS:

NOTL Hydro has provided a detailed OM&A cost table covering the periods from 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year including the variances year over year in **Exhibit 4, Tab 2, Schedule 2**, above.

The following Table 1 identifies those specific accounts where the variance amount in any year exceeds the threshold and thus requires explanation. A “0” indicates that the variance for that specific account in that particular year is below the variance threshold.

Accounts where the variance falls below the threshold in every year are not shown.

Table 1
Summary of OM&A Variances Exceeding Variance Analysis Threshold

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Operations									
5010-Load Dispatching	7,057	2,072	0	0	0	30,679	30,679	30,683	0
5065-Meter Expense	48,842	11,328	(37,514)	18,460	0	10,619	0	13,278	0
Sub-Total	**323,382**	**260,994**	**(37,514)**	**342,844**	**0**	**377,390**	**30,679**	**373,710**	**0**
Maintenance									
5112-Maintenance of Transformer Station Equipment	3,886	51,585	47,699	49,015	0	13,263	(35,752)	20,785	0
5155-Maintenance of Underground Services	14,450	28,028	0	73,310	45,282	53,205	0	53,253	0
5160-Maintenance of Line Transformers	30,518	65,473	34,955	20,554	(44,919)	62,941	42,387	88,680	0
Sub-Total	**304,410**	**388,961**	**82,654**	**431,315**	**363**	**474,671**	**6,635**	**521,359**	**0**
Billing and Collections									
5320-Collecting	47,435	78,207	30,772	103,092	0	74,218	0	76,368	0
Sub-Total	**270,862**	**310,202**	**30,772**	**355,606**	**0**	**312,374**	**0**	**318,798**	**0**
Community Relations									
5415-Energy Conservation	0	29,210	29,210	8,136	0	0	0	0	0
Sub-Total	**713**	**29,210**	**29,210**	**8,783**	**0**	**1,000**	**0**	**1,020**	**0**
Administrative and General Expenses									
5630-Outside Services Employed	25,070	38,545	0	33,645	0	28,500	0	67,283	38,783
5645-Employee Pensions and Benefits	78,275	23,967	(54,308)	19,471	0	22,000	0	22,000	0
Sub-Total	**582,047**	**557,582**	**(54,308)**	**580,205**	**0**	**589,054**	**0**	**649,774**	**38,783**
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	1,085,204	1,247,363	162,159	1,241,397	0	1,212,708	0	1,245,184	32,477
Sub-Total	**1,085,204**	**1,247,363**	**162,159**	**1,241,397**	**0**	**1,212,708**	**0**	**1,245,184**	**32,477**

Explanations of the material variances are provided below:

Operations

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Operations									
5010-Load Dispatching	7,057	2,072	0	0	0	30,679	30,679	30,683	0
5065-Meter Expense	48,842	11,328	(37,514)	18,460	0	10,619	0	13,278	0

- *Account 5010 – 2008 Bridge vs 2007 Actual*

  The variance results from the re-allocation of budget amounts ($30,679) to the proper USoA account 5010 in the 2008 budget from account 5015.

- *Account 5065 – 2006 Actual vs 2006 Board Approved*

  The 2006 Approved amount is based on the 2004 actual amount. In 2004, a backlog of meter re-verification (approx. 700 meters) was cleared up to meet Measurement Canada requirements at that time. Since 2004, NOTL Hydro has taken advantage of the allowed sampling approach to meter re-verification, which has reduced annual costs.

Maintenance

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Maintenance									
5112-Maintenance of Transformer Station Equipment	3,886	51,585	47,699	49,015	0	13,263	(35,752)	20,785	0
5155-Maintenance of Underground Services	14,450	28,028	0	73,310	45,282	53,205	0	53,253	0
5160-Maintenance of Line Transformers	30,518	65,473	34,955	20,554	(44,919)	62,941	42,387	88,680	0

- *Account 5112 – 2006 Actual vs 2006 Board Approved*

  The variance resulted from improper USoA recording of costs of operation activities ($25,000), required Station maintenance and testing activities at York MTS1 and NOTL MTS2 to remain compliant with IESO and NERC system requirements ($21,599) and miscellaneous costs ($1,100).

- *Account 5160 – 2006 Actual vs 2006 Board Approved*

  The variance resulted from implementation of an underground transformer inspection and maintenance program ($34,955).

- *Account 5155 – 2007 Actual vs 2006 Actual*

  The variance resulted from an increase in age related underground service fault repair requirements ($39,178) and outside resource costs associated with repairs ($6,104).

- *Account 5160 – 2007 Actual vs 2006 Actual*

  The variance resulted from a decrease in weather and operations related faults from the rolling average (-$10,000) and a mid year decision to temporarily suspend the underground transformer inspection and maintenance program (-$34,919).

- *Account 5112 – 2008 Bridge vs 2007 Actual*

The variance resulted from the higher level of maintenance activity in 2007 at NOTL MTS2 and York MTS1 to ensure compliance with all IESO and MERC requirements. Maintenance activities are at a minimum level in 2008 with resumption of “rolling” 5 year plan in 2009 to continue to meet NOTL Hydro’s transmission regulatory commitment ($35,741).

- *Account 5160 - 2008 Bridge vs 2007 Actual*

The variance results from the budgeted rolling average for weather and operations related faults ($10,000) and resumption of the underground transformer inspection and maintenance program ($32,404).

Billing & Collection

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Billing and Collections									
5320-Collecting	47,435	78,207	30,772	103,092	0	74,218	0	76,368	0

- *Account 5320 – 2006 Actual vs 2006 Board Approved*

The fiscal year 2006 (and 2007) actual amount and the resulting variance of $30,772 reflects a higher than normal collection effort, which is expected to resume a more normal level in 2008 and 2009. This effort was not anticipated in the 2006 EDR application and was required to catch up with collections which it had been necessary to defer due to programming issues during a complex modification of the customer information and billing system. The purpose of the modification, which is now fully implemented, was to improve efficiency in accessing and updating customer information in situations where customers have multiple sites.

Community Relations

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Community Relations									
5415-Energy Conservation	0	29,210	29,210	8,136	0	0	0	0	0

- *Account 5415 – 2006 Actual vs 2006 approved*

The expenditures in 2006 (and 2007) were for the C&DM program, funded through the 3rd tranche of MARR. The variance of $29,210 results from the 2006 Board approved amount being zero, because in the 2004 data used for the 2006 EDR, C&DM expenses were recorded to account 1565. Starting in 2006, in accordance with the OEB APH FAQ, Question 2, of December 2005, NOTL Hydro recorded C&DM expenses in account 5415 with corresponding entries in accounts 1565 and 1566.

Administrative & General Expenses

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Administrative and General Expenses									
5630-Outside Services Employed	25,070	38,545	0	33,645	0	28,500	0	67,283	38,783
5645-Employee Pensions and Benefits	78,275	23,967	(54,308)	19,471	0	22,000	0	22,000	0

- *Account 5630 – 2009 Test vs 2008 Bridge*

The majority of the variance results from inclusion in 2009 of 1/3rd of the total cost to be incurred as a result of the 2009 rates rebasing. The reason for the 1/3rd factor is that the objective is to recover the total cost through rates over the 3-year period from 2009 to 2011 to which the rates are currently expected to apply before the next re-basing. Thus, over 3 years, the full cost would be recovered. The cost would include consulting and potential legal fees incurred by NOTL Hydro, as well as potential OEB cost orders applied to NOTL Hydro related to recovery of OEB costs and eligible intervener costs. The final cost is very uncertain at this time as it will depend on the level of interrogatories, interveners' intervention, and how the expected oral technical conference or oral hearing process proceeds. However, NOTL Hydro's current best judgment as to the total cost amount to be used in this application is $100,000. Thus, for the 2009 test-year, one third ($33,333) of the $100,000 is included in the OM&A expenses and is thus in the variance amount.

The variance also includes an increase of $3,000 in consulting and EUSA fees for NOTL Hydro's safety "Zero Quest" program. NOTL Hydro was awarded the EUSA Gold Award in 2008 and is targeting achievement of the Platinum Award by 2011.

The remaining variance of $2,450 results from miscellaneous other items.

- *Account 5645 – 2006 Actual vs 2006 Board Approved*

NOTL Hydro's accounting practice is to allocate the OMERS premium employer costs for employees across the various operating or capital activities of the company based on the employee hours worked in these activities. As such, they are not normally included in account 5645. Account 5645 would include only post-retirement benefits for retirees. For the purposes of preparing the 2006 rate application however, it was concurred with OEB staff that the amounts allocated out for OMERS premiums in the 2004 data should be allocated back to 5645. The 2006 actual and the variance of $-54,308 reflects the normal accounting practice described above.

Amortization Expenses

Expense Description	2006 Board Approved	2006 Actual	Material Variance from 2006 Board Approved	2007 Actual	Material Variance from 2006 Actual	2008 Bridge	Material Variance from 2007 Actual	2009 Test	Material Variance from 2008 Bridge
Amortization Expenses									
5705-Amortization Expense - Property, Plant, and Equipment	1,085,204	1,247,363	162,159	1,241,397	0	1,212,708	0	1,245,184	32,477

Account 5705 - 2006 Actual vs 2006 Approved

The 2006 Board approved amount is based on the 2004 actual amount in accordance with the OEB 2006 rate model. The majority of the variance ($109,245) relates to the computer software asset and is due to the 2006 Board approved amount not reflecting amortization of more than 2 years of investment made by NOTL Hydro in a new integrated customer information, billing and financial system, through to the 2006 actual. Another component of the variance ($30,438) results from an asset continuity adjustment made in 2004 for the poles, towers and fixtures account, required to correct prior year recording errors. Smaller non-material variances totalling $22,476 occur for amortization of various other asset accounts.

- *Account 5705 – 2009 Test vs 2008 Bridge*

The variance comprises increases in depreciation expense resulting from investments in the various asset accounts in 2009 and the remaining 50% of 2008 investments (1/2 year rule), net of decreases for assets that have been fully depreciated in prior years. The specific depreciation expense variances are $17,983 for account 1840 underground conduit, $12,162 for account 1845 underground conductors and devices, $6,996 for account 1835 overhead conductors and devices, $6,480 for account 1850 line transformers, and a decrease of $13,886 for account 1925 computer software and a net increase $2,908 for all other accounts combined.

SHARED SERVICES:

The recent revisions to the Affiliate Relations Code narrows the scope of shared activities between LDCs and their affiliates. NOTL Hydro had a shared services agreement in place with Energy Services Niagara Inc. ("ESNI") prior to September, 2007 and is therefore eligible to continue the activities listed below for a period of up to five years:

- customer service representatives to perform billing, collecting and customer inquiry research for ESNI rental water heaters and water/wastewater customer accounts.
- Provide accounting/administrative personnel for accounting and administrative services.
- Provide line and engineering personnel for street light and water heater maintenance, as well as meter reading services.
- Provide management personnel to oversee billing, collecting, customer service, accounting, administrative, engineering and line activities.
- Provide contractors, materials and equipment for Niagara-on-the-Lake Hydro Inc. employees to perform the above functions.
- Provide office space for ESNI to carry on their business.

NOTL Hydro fully recovers its costs for the above activities from ESNI using a 'cost plus' cost determination methodology:

- Monthly invoices to ESNI include a 20% mark up on actual labour costs, 10% on truck and contractors and a total of 10% on all material supplied.
- A 'Building Overhead' surcharge is affixed to ESNI based on its estimated square foot occupation of the building. A 5% of costs plus 10% mark up is utilized for the building overhead.

Due to the ongoing nature of the business activities of ESNI, the services provided by Niagara-on-the-Lake Hydro Inc. to ESNI are on a continuing basis. Periodic increases in labour, equipment, contractor and material costs affecting Niagara-on-the-Lake Hydro

Inc. are immediately passed on to ESNI. The rate structure utilized by Niagara-on-the-Lake Hydro Inc. to invoice Energy Services Niagara Inc. is consistent with that utilized to invoice any current customer, client, organization or the public as a whole for work performed.

PURCHASE OF SERVICES:

This schedule identifies the distribution expenses incurred through the purchase of services for the years 2006 (actual), 2007 (actual), the 2008 bridge year and the 2009 test year. The amounts shown are included in the OM&A costs tabulated in **Exhibit 4, Tab 2, Schedule 1**. For 2008 and 2009, the specific vendor for some service items may not be have been selected at the time of application, and this is indicated in the tables below where applicable. For materiality, only vendors where the cost exceeds $1,000 are listed. For each vendor, the Table also specifies the OEB USoA accounts where the vendor amount is included in the OM&A costs and the pricing methodology.

NIAGARA ON THE LAKE HYDRO INC

PURCHASE OF SERVICES ACTUAL 2006

Name of Company	Activity	Pricing	OEB Account	$ Amount	
Accountemps	Casual Labour	Contract	5615	4,285	
					4,285
Adam Building Mtce	Office Cleaning	Contract	5675	1,594	
					1,594
AGO	Safety Clothing	Market Price	5025	2,268	
AGO	Safety Clothing	Market Price	5045	222	
					2,490
Aurora Electric	Building Mtce	Hourly Rate/Materials	5155	706	
Aurora Electric	Building Mtce	Hourly Rate/Materials	5675	2,299	
					3,005
Avakian Computer Systems	Computer Mtce	Hourly Rate	5025	797	
Avakian Computer Systems	Computer Mtce	Hourly Rate	5085	216	
Avakian Computer Systems	Computer Mtce	Hourly Rate	5315	1,012	
Avakian Computer Systems	Computer Mtce	Hourly Rate	5620	1,012	
					3,037
Beatties	Line Supplies	Market Price/Less Discount	5085	685	
Beatties	Billing Supplies	Market Price/Less Discount	5315	1,301	
Beatties	Office Supplies	Market Price/Less Discount	5415	37	
Beatties	Office Supplies	Market Price/Less Discount	5620	882	
Beatties	Line Supplies	Market Price/Less Discount	5675	274	
					3,179
Bell Canada	Phone Service-Main Office	Market Price/Less Discount	5085	1,760	
Bell Canada	Circuit to York Rd	Market Price/Less Discount	5112	464	
Bell Canada	Phone Service-Main Office	Market Price/Less Discount	5315	1,760	
Bell Canada	Phone Service-Main Office	Market Price/Less Discount	5620	1,868	
					5,852
Bell Mobility	Cell Phones/Lines	Market Price/Less Discount	5085	4,069	
Bell Mobility	Cell Phones/Mgr	Market Price/Less Discount	5620	425	
					4,495
Brite-lite Inc	LED Lights	Market Price/Less Discount	5415	6,238	
					6,238
Burlington Business Forms	Envelopes/Hydro Bills	Market Price/Less Discount	5315	10,107	
Burlington Business Forms	Forms	Market Price/Less Discount	5025	1,027	
Burlington Business Forms	Line Supplies	Market Price/Less Discount	5005	6	
Burlington Business Forms	Line Supplies	Market Price/Less Discount	5085	137	
Burlington Business Forms	Billing Supplies	Market Price/Less Discount	5310	43	
Burlington Business Forms	Office Supplies	Market Price/Less Discount	5620	411	
					11,731
CIBC	EFT Charges	Market Price/Less Discount	5320	8,861	
CIBC	EFT Charges	Market Price/Less Discount	5665	6,089	
					14,950
Canadian Door Doctor	Door Repairs/Mtce	Hourly Rate/Materials	5675	1,418	
					1,418
Central Comminucations	Answering Service	Contract	5085	1,720	
Central Comminucations	Answering Service	Contract	5315	192	
Central Comminucations	Answering Service	Contract	5615	192	
					2,104
Century Vallen	Safety Supplies	Market Price	5025	759	
Century Vallen	Safety Supplies	Market Price	5045	218	
Century Vallen	Safety Supplies	Market Price	5675	421	
					1,397
Cogeco Cable	Internet Billing	Market Price	5315	402	
Cogeco Cable	Internet Admin	Market Price	5620	337	
Cogeco Cable	Internet Lines	Market Price	5085	402	
					1,140
Collective Utility	Meter Reading	Contract	5310	25,801	
					25,801
COS Computer Solutions	Computer Mtce/License Fee	Contract	5025	669	
COS Computer Solutions	Computer Mtce/License Fee	Contract	5315	669	
COS Computer Solutions	Computer Mtce/License Fee	Contract	5620	669	
					2,006
Crawford Smith & Swallow	Auditing Fees	Contract	5630	25,000	
					2,500
Davis Fence	Fencing	Hourly Rate/Materials	5112	4,095	
					4,095

Drakar Engineering	Glove Testing	Contract	5025	2,022	
Drakar Engineering	Glove Testing	Contract	5045	219	
Drakar Engineering	Glove Testing	Contract	5125	151	
					2,392
Dromey Design	Scada Mtce	Hourly Rate	5025	924	
Dromey Design	Scada Mtce	Hourly Rate	5125	462	
Dromey Design	Scada Mtce	Hourly Rate	5150	462	
					1,849
Dundas Power Line	Transformer Testing	Contract	5035	25,044	
					25,044
EDA	Membership Fees	Market Price	5665	11,550	
					11,550
Enbridge Gas	Heating Costs	Market Price	5675	5,898	
					5,898
EZ-Shred	Document Shredding	Market Price/Less Discount	5315	399	
EZ-Shred	Document Shredding	Market Price/Less Discount	5620	644	
					1,042
G.Snow's Roofing	Building Mtce	Tender/Quotes	5675	2,700	
					2,700
GMS	Health Benefits	Market Price/Less Discount	5645	9,645	
					9,645
Grafton	Line Supplies	Market Price/Less Discount	5055	272	
Grafton	Line Supplies	Market Price/Less Discount	5160	2,875	
					3,147
Green Line Equipment	Equip Repair	Hourly Rate/Materials	5675	1,191	
					1,191
Green Shield	Health Benefits	Market Price/Less Discount	5645	7,644	
					7,644
Ground Aerial Mtce	Transformer Cleaning	Contract	5160	16,667	
					16,667
Hamm	Corp Service Asst	Hourly	5315	226	
Hamm	Corp Service Asst	Hourly	5320	1,433	
Hamm	Corp Service Asst	Hourly	5615	21,004	
Hamm	Corp Service Asst	Hourly	5665	38	
					22,700
Hydro One Networks	Operating Expenses	Market Price	5112	25,000	
Hydro One Networks	Operating Expenses	Market Price	5630	5,500	
					30,500
JBM Office Supplies	Copier Mtce/Line Supplies	Market Price/Less Discount	5085	649	
JBM Office Supplies	Copier Mtce/Billing Supplies	Market Price/Less Discount	5315	107	
JBM Office Supplies	Copier Mtce/Admin Supplies	Market Price/Less Discount	5620	251	
JBM Office Supplies	Copier Mtce	Market Price/Less Discount	5675	106	
					1,112
Ken Penrose	Team Workshop	Hourly Rate	5615	5,795	
					5,795
Kinetiq Canada	License Fee	Contract	5315	6,519	
					6,519
Lyreco	Line Supplies	Market Price/Less Discount	5085	1,665	
Lyreco	Billing Supplies	Market Price/Less Discount	5315	1,966	
Lyreco	Billing Supplies	Market Price/Less Discount	5320	-44	
Lyreco	Admin Supplies	Market Price/Less Discount	5620	1,241	
					4,828
M301	Refrigeration Retirement	Market Price/Less Discount	5415	12,835	
					12,835
Manpower	Casual Labour	Contract	5320	1,149	
					1,149
Mearie Insurance	Insurance/Premium	Market Price/Less Discount	5640	25,146	
					25,146
Mearie Management	LTD & Life Insurance	Market Price/Less Discount	5645	5,039	
					5,039
Modern Landfill	Dump Fees	Market Price	5120	2,918	
Modern Landfill	Dump Fees	Market Price	5620	96	
Modern Landfill	Dump Fees	Market Price	5675	702	
1					**3,716**

	Niagara Analytic	PCB Analysis	Market Price	5055	1,800	
						1,800
	Niagara Community News	Advertising	Market Price/Less Discount	5315	158	
	Niagara Community News	Advertising	Market Price/Less Discount	5415	614	
	Niagara Community News	Advertising	Market Price/Less Discount	5630	212	
	Niagara Community News	Advertising	Market Price/Less Discount	5660	1,318	
						2,302
	Niagara Falls Hydro Services	Metering Interrogation/ Clean	Contract	5175	45	
	Niagara Falls Hydro Services	Meter Reading	Contract	5310	3,840	
						3,885
	Oshawa Public Utilities	Station Mtce Fees	Contract	5015	1,560	
	Oshawa Public Utilities	Station Mtce Fees	Contract	5112	2,310	
						3,870
	Peninsula Video & Sound Inc	Locates	Contract	5045	33,450	
						33,450
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5025	125	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5065	20	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5075	2	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5085	181	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5112	16	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5114	40	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5125	800	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5150	67	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5155	350	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5160	209	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5175	14	
	Penner Building Supplies	Billing Supplies	Market Price/Less Discount	5310	24	
	Penner Building Supplies	Billing Supplies	Market Price/Less Discount	5320	280	
	Penner Building Supplies	Line Supplies	Market Price/Less Discount	5675	3,731	
						5,861
	Pineridge Tree Service	Tree Trimming	Tender	5135	68,975	
						68,975
	Pitney Bowes	Postage Rental	Contract	5315	1,556	
	Pitney Bowes	Postage Rental	Contract	5315	3,834	
						5,390
	Postage By Phone	Postage Refill-Billing	Market Price	5315	41,944	
	Postage By Phone	Postage Refill-Admin	Market Price	5620	2,400	
						44,344
	Provincial Cleaning	Office Cleaning	Contract	5675	7,905	
						7,905
	Quasar	Safety Audit	Hourly Rate	5025	2,107	
						2,107
	Ravine Engineering	Engineering Consultant Scada	Hourly Rate	5112	3,750	
						3,750
	Rogers Telecom	Long Distance/Lines	Market Price/Less Discount	5085	513	
	Rogers Telecom	Long Distance/Billing	Market Price/Less Discount	5315	203	
	Rogers Telecom	Long Distance/Admin	Market Price/Less Discount	5620	352	
						1,068
	Rondar Inc	Inspection	Hourly Rate	5114	2,505	
						2,505
	Service Experts	Mtce on Furnace	Contract	5675	1,257	
						1,257
	Shepherds Utility	Safety Supplies	Market Price	5025	1,946	
	Shepherds Utility	Safety Supplies	Market Price	5120	172	
	Shepherds Utility	Safety Supplies	Market Price	5125	1,357	
	Shepherds Utility	Safety Supplies	Market Price	5150	331	
						3,806
	SPI	Ebt Hub Service	Contract	5315	7,334	
						7,334
	Stangl's Enviro Lawn Care	Lawn Care	Contract	5112	571	
	Stangl's Enviro Lawn Care	Lawn Care	Contract	5114	376	
	Stangl's Enviro Lawn Care	Lawn Care	Contract	5675	143	
1						**1,090**

Tiltran Services	Dist Station Mtce	Contract	5112	10,254	
Tiltran Services	Reclosure Inspection	Contract	5114	1,982	
					12,237
Town Of Niagara On The Lake	Computer Support/Lines	Contract	5025	1,352	
Town Of Niagara On The Lake	Computer Support/Billing	Contract	5315	1,352	
Town Of Niagara On The Lake	Computer Support/Admin	Contract	5620	1,352	
					4,056
Vaxine Computer	Annual Proxy/FTP/Lines	Contract	5085	163	
Vaxine Computer	Annual Proxy/FTP/Billing	Contract	5315	273	
Vaxine Computer	Annual Proxy/FTP/Admin	Contract	5620	757	
					1,194
Verge Insurance	Property	Market Price/Less Discount	5635	23,223	
					23,223
Virelec Ltd	Engineering Consultant Scada	Hourly Rate	5112	1,440	
					1,440
Waterloo North Hydro Inc	TS Monitoring	Contract	5112	2,032	
					2,032
Welland Hydro Electric	Computer Mtce	Contract	5020	200	
Welland Hydro Electric	Computer Mtce	Contract	5025	160	
Welland Hydro Electric	Computer Mtce	Contract	5045	200	
Welland Hydro Electric	Computer Mtce	Contract	5315	8,086	
Welland Hydro Electric	Computer Mtce	Contract	5620	160	
					8,807
Wickens Industrial	Transformer Mtce	Contract	5160	10,863	
					10,863
Wiens Underground Electric	U/G Services	Tender	5155	1,349	
					1,349
Workplace Safety Group	Registration Permits	Market Price			
Xerox Canada	Photocopier Lease	Contract	5085	1,227	**12,326**
Xerox Canada	Photocopier Lease	Contract	5315	2,299	
Xerox Canada	Photocopier Lease	Contract	5620	1,729	
Xerox Canada	Photocopier Lease	Contract	5675	4,376	**9,631**
Grand Total 2006					**597,281**

NIAGARA ON THE LAKE HYDRO INC

PURCHASE OF SERVICES ACTUAL 2007

Name of Company	Activity	Pricing	OEB Account	$ Amount	
AccountTemps	Casual Labour	Contract	5320	8,500	
AccountTemps	Casual Labour	Contract	5615	8,694	
					17,194
AGO Industries	Safety Clothing	Market Price	5025	1,016	
AGO Industries	Safety Clothing	Market Price	5045	1,016	
					2,032
Alison's Sport Awards	Employee Jackets	Market Price/Less Discount	5665	2,843	
					2,843
American Casting	Meter Seals	Market Price	5175	1,160	
					1,160
Aurora Electrical	Building Mtce	Hourly Rate/Materials	5075	935	
Aurora Electrical	Building Mtce	Hourly Rate/Materials	5155	563	
Aurora Electrical	Building Mtce	Hourly Rate/Materials	5675	1,873	
					3,371
Avakian Computer	Software Mtce	Contract	5025	1,496	
Avakian Computer	Computer Support	Contract	5315	635	
Avakian Computer	Computer Support	Contract	5620	635	
					2,765
Beatties Supplies	Line Supplies	Market Price/Less Discount	5085	1,259	
Beatties Supplies	Office Supplies	Market Price/Less Discount	5315	1,603	
Beatties Supplies	Office Supplies	Market Price/Less Discount	5415	7	
Beatties Supplies	Office Supplies	Market Price/Less Discount	5425	92	
Beatties Supplies	Office Supplies	Market Price/Less Discount	5620	1,183	
					4,145
Bell Canada	Phone use-York TX	Market Price/Less Discount	5015	724	
Bell Canada	Phone use-Dist St	Market Price/Less Discount	5085	1,357	
Bell Canada	Phone use	Market Price/Less Discount	5315	1,491	
Bell Canada	Phone Use Main Office	Market Price/Less Discount	5620	1,491	
					5,063
Bell Mobility	Cell Phones	Market Price/Less Discount	5085	4,892	
Bell Mobility	Cell Phones	Market Price/Less Discount	5605	31	
Bell Mobility	Cell Phones	Market Price/Less Discount	5620	502	
					5,424
Bell Pole Rental	Pole Rental	Market Price	5095	17,639	
					17,639
Burlington Business Forms	Line Supplies	Market Price/Less Discount	5085	1,082	
Burlington Business Forms	Office Supplies	Market Price/Less Discount	5310	230	
Burlington Business Forms	Office Supplies	Market Price/Less Discount	5315	4,064	
Burlington Business Forms	Office Supplies	Market Price/Less Discount	5320	2,061	
Burlington Business Forms	Office Supplies	Market Price/Less Discount	5620	74	
					7,511
C.O.S Computer Solutions	Software Mtce	Contract	5025	619	
C.O.S Computer Solutions	Software Mtce	Contract	5315	6,369	
C.O.S Computer Solutions	Software Mtce	Contract	5620	619	
					7,606
Canadian Door Doctor	Building Mtce	Hourly Rate/Materials	5675	4,126	
					4,126
CCS Transportation Safety	Training	Hourly rate	5020	2,085	
CCS Transportation Safety	Training	Hourly rate	5045	2,375	
CCS Transportation Safety	Training	Hourly rate	5065	1,410	
					5,870
Central Communications	Answering service	Contract	5065	45	
Central Communications	Answering service	Contract	5085	2,052	
					2,098
Cogeco Cable	Internet Services	Market Price	5085	403	
Cogeco Cable	Internet Services	Market Price	5315	101	
Cogeco Cable	Internet Services	Market Price	5315	301	
Cogeco Cable	Internet Services	Market Price	5620	403	
					1,208
Collective Utility	Meter Reading	Contract	5310	30,271	
					30,271
Collus Power Corp	Codac Costs	Contract	5630	1,029	
					1,029

Country Lawns	Snow Removal	Contract	5112	1,334	
Country Lawns	Snow Removal	Contract	5112	770	
Country Lawns	Snow Removal	Contract	5114	480	
Country Lawns	Snow Removal	Contract	5114	430	
Country Lawns	Snow Removal	Contract	5675	5,281	
					8,295
Crawford Smith & Swallow	Audit Fees	Contract	5630	16,748	
					16,748
Credit Bureau	Collection Charges	Contract	5320	1,222	
Credit Bureau	Collection Charges	Contract	5335	-349	
Credit Bureau	Legal Fees	Contract	5630	1,573	
					2,446
Digital Boundary	Security Audit	Hourly Rate	5630	13,500	
					13,500
Drakar Engineering	Glove testing	Contract	5025	2,049	
					2,049
EDA	Membership Renewal	Market Price	5665	11,890	
					11,890
CIBC	EFT Charges	Contract	5320	3,079	
CIBC	EFT Charges	Contract	5620	1,968	
CIBC	EFT Charges	Contract	5665	2,862	
					7,909
Enbridge Gas	Heating Costs	Market Price	5675	6,645	
					6,645
Ennerconnect Inc	Interval Meter reading	Contract	5310	2,243	
					2,243
ESA Fee	Fees	Contract	5680	4,367	
					4,367
ESRI Canada	Software Mtce	Contract	5025	5,249	
					5,249
EZ-Shred	Shredding	Market Price/Less Discount	5315	531	
EZ-Shred	Shredding	Market Price/Less Discount	5620	531	
					1,062
GAMS	Transformer Inpsection	Contract	5035	14,580	
GAMS	Transformer Inpsection	Contract	5055	14,510	
GAMS	Transformer Inpsection	Contract	5160	29,090	
					58,180
GMS	Health Benefits	Contract	5645	13,871	
					13,871
Grand & Toy	Line Supplies	Market Price/Less Discount	5085	37	
Grand & Toy	Office Supplies	Market Price/Less Discount	5315	417	
Grand & Toy	Office Supplies	Market Price/Less Discount	5620	572	
					1,027
Hamm	Corp Service Asst	Contract	5315	589	
Hamm	Corp Service Asst	Contract	5320	569	
Hamm	Corp Service Asst	Contract	5415	183	
Hamm	Corp Service Asst	Contract	5615	24,882	
Hamm	Corp Service Asst	Contract	5620	53	
Hamm	Corp Service Asst	Contract	5655	206	
Hamm	Corp Service Asst	Contract	5665	66	
Hamm	Corp Service Asst	Contract	5025	37	
					26,584
Horizon Utility	Labour	Hourly Rate	5160	1,321	
					1,321
Hydro One Networks	Pole Rental	Market Price	5095	1,509	
					1,509
Indeco Stategic Consulting	OPA	Contract	5415	7,500	
					7,500
Intergrated Business Int	Computer Support	Hourly Rate	5025	496	
Intergrated Business Int	Computer Support	Hourly Rate	5315	496	
Intergrated Business Int	Computer Support	Hourly Rate	5620	2,291	
					3,283

Jim Neufeld	CPR/First Aid Training	Hourly Rate	5020	453	
Jim Neufeld	CPR/First Aid Training	Hourly Rate	5045	315	
Jim Neufeld	CPR/First Aid Training	Hourly Rate	5065	138	
Jim Neufeld	CPR/First Aid Training	Hourly Rate	5315	300	
Jim Neufeld	CPR/First Aid Training	Hourly Rate	5615	300	
					1,505
Kinetiq Canada	Computer Support	Contract	5315	6,278	
					6,278
L St Amand	Screenings	Market Price	5075	89	
L St Amand	Screenings	Market Price	5120	354	
L St Amand	Screenings	Market Price	5155	104	
L St Amand	Building Mtce	Market Price	5675	725	
					1,272
Lancaster, Brooks & Welch	Legal Fees	Hourly Rate	5315	332	
Lancaster, Brooks & Welch	Legal Fees	Hourly Rate	5630	1,351	
					1,683
Loud Advertising	Summer Savings	Contract	5415	9,379	
					9,379
Mearie	Training	Market Price/Less Discount	5045	1,514	
Mearie	Liability Policy	Market Price/Less Discount	5640	19,813	
Mearie	Vehicle Insurance	Market Price/Less Discount	5640	7,696	
Mearie	Life & LTD Insurance	Market Price/Less Discount	5645	4,785	
					33,807
Mearie Electric Association	Property Premium	Market Price/Less Discount	5635	5,323	
					5,323
Mearie Management	Actuarial Services	Market Price/Less Discount	5630	4,390	
					4,390
Micro Tech Niagara	Computer Support	Hourly Rate	5315	6,633	
Micro Tech Niagara	Computer Support	Hourly Rate	5315	96	
Micro Tech Niagara	Computer Support	Hourly Rate	5620	7,702	
Micro Tech Niagara	Software Mtce	Hourly Rate	5025	6,520	
					20,951
Micro-Age	Software Mtce	Hourly Rate	5025	1,080	
					1,080
Modern Landfill	Dump Fee	Market Price	5025	1,325	
Modern Landfill	Dump Fees	Market Price	5675	1,994	
					3,319
Naschem	Line Supplies	Market Price	5125	395	
Naschem	Building Mtce	Market Price	5675	748	
					1,143
Niagara Analytical	PCB Analysis	Market Price	5160	3,150	
					3,150
Niagara Community Newspapers	Advertising	Market Price/Less Discount	5025	941	
Niagara Community Newspapers	Advertising	Market Price/Less Discount	5415	228	
Niagara Community Newspapers	Advertising	Market Price/Less Discount	5655	627	
Niagara Community Newspapers	Advertising	Market Price/Less Discount	5660	1,215	
					3,011
Niagara Falls Hydro Services	Meter Mtce	Contract	5065	280	
Niagara Falls Hydro Services	Meter Mtce	Contract	5175	3,405	
Niagara Falls Hydro Services	Meter Mtce	Contract	5310	960	
					4,645
Niagara On The Lake Energy Inc	Mgmt Fees	Contract	5665	20,045	
					20,045
Oshawa Public Utilities	Metering/Station Mtce	Contract	5112	2,380	
Oshawa Public Utilities	Metering/Station Mtce	Contract	5112	2,380	
					4,760
Peninsula Video & Sound	Locates	Contract	5045	12,350	
Peninsula Video & Sound	Locates	Contract	5075	16,934	
					29,284

Penner Building Centre	Supplies	Market Price/Less Discount	5025	410	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5075	22	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5120	29	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5125	35	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5135	17	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5150	5	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5155	526	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5160	150	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5425	67	
Penner Building Centre	Office Supplies	Market Price/Less Discount	5620	10	
Penner Building Centre	Building Mtce	Market Price/Less Discount	5675	4,249	
					5,519
Pitney Bowes	Postage Supplies	Market Price	5315	1,271	
Pitney Bowes	Postage Meter rental	Contract	5315	3,859	
					5,131
Postage By Phone	Postage	Market Price	5315	36,600	
Postage By Phone	Postage	Market Price	5620	3,445	
					40,045
Provincial Janitorial	Office Cleaning	Contract	5675	9,540	
					9,540
Ravine Engineering	Engineering consultants	Hourly Rate	5112	3,967	
Ravine Engineering	Engineering consultants	Hourly Rate	5112	1,672	
					5,640
Regional Tree Service	Tree trimming	Tender	5135	67,500	
					67,500
Shepell.FGI Ltd	Workshop Pressure	Hourly Rate	5615	1,500	
					1,500
Shepherds Utility	Safety Tools	Market Price	5025	2,910	
Shepherds Utility	Safety Tools	Market Price	5045	226	
Shepherds Utility	Line Supplies	Market Price	5125	351	
					3,487
Simeon Go	Safety Consultant	Hourly Rate	5020	300	
Simeon Go	Safety Consultant	Hourly Rate	5025	3,820	
Simeon Go	Safety Consultant	Hourly Rate	5045	175	
					4,295
SPI Group	Hub Support/Service	Contract	5315	1,800	
SPI Group	Hub Support/Service	Contract	5315	6,480	
					8,280
Tiltran Services	Station Mtce	Contract	5112	8,295	
Tiltran Services	Station Mtce	Contract	5112	9,704	
Tiltran Services	Station Mtce	Contract	5114	379	
Tiltran Services	Station Mtce	Contract	5125	2,810	
					21,188
Town Of NOTL	Computer Support	Contract	5025	2,101	
Town Of NOTL	Computer Support	Contract	5315	2,176	
Town Of NOTL	Computer Support	Contract	5620	2,101	
					6,378
Turolight Inc	Conservation Supplies	Market Price/Less Discount	5415	5,082	
					5,082
Utilities Standard	USF Membership	Contract	5025	5,000	
					5,000
Verge Insruance	Property Premium	Market Price/Less Discount	5635	18,658	
					18,658
Waterloo North Hydro	TS Monitoring	Contract	5112	6,096	
Waterloo North Hydro	TS Monitoring	Contract	5112	6,096	
					12,192
Welland Hydro	Computer Support	Contract	5025	279	
Welland Hydro	Information Services	Contract	5315	679	
Welland Hydro	Computer Support	Contract	5315	785	
Welland Hydro	Computer Support	Contract	5620	311	
					2,054
Wiens Underground Inst	MTCE U/G Services	Tender	5155	11,721	
					11,721
Workplace Safety Group	Access Permits	Market Price	5045	1,256	
1					**1,256**

Xerox	Copier Lease	Contract	5025	3,769	
Xerox	Copier Lease	Contract	5085	1,676	
Xerox	Copier Lease	Contract	5315	5,580	
Xerox	Copier Lease/Copy Charges	Contract	5620	5,245	
					16,270
Grand Total 2007					**722,794**

NIAGARA ON THE LAKE HYDRO INC

PURCHASE OF SERVICES 2008

Name of Company	Activity	Pricing	OEB Account	$ Amount	
Abloy Canada Inc	Metering Supplies	Market Price	5175	1,000	
					1,000
AGO Industries	Safety Clothing	Market Price	5025	1,750	
AGO Industries	Safety Clothing	Market Price	5045	1,750	
					3,500
Alliance Security	Building Security	Contract	5675	2,000	
American Casting	Meter Seals	Market Price	5065	250	
American Casting	Metering Supplies	Market Price	5175	1,000	
					3,250
Beatties Supplies	Line Supplies	Market Price/Less Discount	5085	700	
Beatties Supplies	Billing Supplies	Market Price/Less Discount	5315	4,500	
Beatties Supplies	Office Supplies	Market Price/Less Discount	5620	2,780	
					7,980
Bell Canada	Phone, Data Line	Market Price/Less Discount	5015	1,000	
Bell Canada	Phone Lines	Market Price/Less Discount	5085	3,285	
Bell Canada	Phone Billing	Market Price/Less Discount	5315	1,550	
Bell Canada	Phone Admin	Market Price/Less Discount	5620	2,000	
					7,835
Bell Mobility	Phone Lines	Market Price/Less Discount	5085	5,000	
Bell Mobility	General Mgr Expenses	Market Price/Less Discount	5605	500	
Bell Mobility	Phone Admin	Market Price/Less Discount	5620	500	
					6,000
Bell Pole Rental	O/H Rental	Contract	5095	18,800	
					18,800
Burlington Business Forms	Line Supplies	Market Price/Less Discount	5085	500	
Burlington Business Forms	Metering Reading Billing Supplies	Market Price/Less Discount	5310	250	
Burlington Business Forms	Billing Supplies	Market Price/Less Discount	5315	900	
					1,650
C.O.S Computer Solutions	Computer Mtce	Contract	5675	2,027	
					2,027
Canadian Door Doctor	Repairs	Hourly Rate/Materials	5675	2,500	
					2,500
Central Communications	Phone Lines	Contract	5085	2,100	
					2,100
CIBC	EFT Charges/Global Payment	Market Price/Less Discount	5320	6,200	
CIBC-EFT Charges	Office Supplies	Market Price/Less Discount	5620	6,500	
					12,700
Cintas	Billing Supplies	Market Price/Less Discount	5315	550	
Cintas	Office Supplies	Market Price/Less Discount	5620	550	
					1,100
Cogeco Cable	Internet Lines	Market Price	5085	415	
Cogeco Cable	Internet Billing	Market Price	5315	450	
Cogeco Cable	Internet Admin	Market Price	5620	500	
					1,365
Collective Utility	Meter Reading	Contract	5310	35,000	
					35,000
Country Lawns	Snow Removal	Contract	5112	2,400	
Country Lawns	Snow Removal	Contract	5114	500	
Country Lawns	Snow Removal	Contract	5675	2,500	
					5,400
Crawford Smith & Swallow	Audit Fees	Contract	5630	20,000	
					20,000
Credit Bureau	Collection Charges	Market Price/Less Discount	5320	1,000	
					1,000
Drakar Eng/Commercial Equip	Safety Items Lines/Glove Testing	Contract	5025	2,000	
					2,000
E&USA Audit	Admin Expenses-Outside Services	Contract	5630	5,000	
					5,000
EDA	Training/Seminars	Market Price	5005	2,500	
EDA	Seminars/Expenses	Market Price	5305	900	
EDA	Seminars/Expenses	Market Price	5315	2,700	
EDA	Seminars/Expenses	Market Price	5605	2,000	
EDA	Seminars/Expenses	Market Price	5610	450	
EDA	Seminars/Expenses	Market Price	5615	600	
EDA	Membership Renewal	Contract	5665	12,500	
					21,650

Enbridge Gas	Heating	Market Price	5675	7,000	
					7,000
Enerconnect Inc	Interval Meter reading	Contract	5310	4,485	
					4,485
ESA Fee	Fees	Contract	5680	5,370	
					5,370
ESRI Computer Mtce	Computer Mtce-Scada Mtce	Contract	5675	4,277	
					4,277
EUSA	Training/Seminars-Mgmt	Contract	5005	2,500	
EUSA	Training/Seminars	Contract	5025	6,000	
EUSA	Training/Seminars	Contract	5045	1,500	
EUSA	Training/Seminars	Contract	5065	1,500	
					11,500
GAMS	Transformer Inspection	Contract	5035	2,000	
GAMS	Transformer Inspection	Contract	5055	1,500	
GAMS	Mtce O/H Services	Contract	5130	7,500	
GAMS	Transformer Inspection	Contract	5160	5,000	
					16,000
GMS	Health Benefits	Market Price/Less Discount	5645	11,000	
					11,000
Grafton	Transformer Inpsection	Contract	5160	8,500	
					8,500
Grand & Toy	Line Supplies	Market Price/Less Discount	5025	100	
Grand & Toy	Line Supplies	Market Price/Less Discount	5085	900	
Grand & Toy	Billing Supplies	Market Price/Less Discount	5315	2,700	
Grand & Toy	Office Supplies	Market Price/Less Discount	5620	2,780	
					6,480
Jim Neufeld	Safety Training	Hourly Rate	5025	750	
Jim Neufeld	Safety Training	Hourly Rate	5045	750	
Jim Neufeld	Safety Training	Hourly Rate	5065	500	
Jim Neufeld	Safety Training	Hourly Rate	5315	500	
Jim Neufeld	Safety Training	Hourly Rate	5615	300	
					2,800
Kinetiq Canada	Computer Mtce	Contract	5675	6,696	
					6,696
L St Amand	Screenings	Market Price	5120	500	
L St Amand	Screenings	Market Price	5675	1,000	
					1,500
Lancaster, Brooks & Welch	Legal Fees	Hourly Rate	5630	2,000	
					2,000
Mearie	Seminars/Expenses	Market Price/Less Discount	5610	450	
Mearie	Seminars/Expenses	Market Price/Less Discount	5615	600	
Mearie	Insurance/Liability Policy	Market Price/Less Discount	5640	28,000	
Mearie	Life & LTD Insurance	Market Price/Less Discount	5645	11,000	
Mearie Electric Association	Property Premium	Market Price/Less Discount	5635	21,000	
					61,050
Micro Tech Niagara	Computer Mtce	Hourly Rate	5675	32,000	
					32,000
Modern Landfill	Dump Fees	Market Price	5120	2,000	
Modern Landfill	Dump Fees	Market Price	5675	5,000	
					7,000
Niagara Analytical	Line Supplies(water/oil sampling)	Market Price	5015	2,000	
Niagara Analytical	PCB Analysis	Market Price	5160	3,000	
					5,000
Niagara Community Newspapers	Advertising	Market Price/Less Discount	5660	1,000	
					1,000
Niagara Falls Hydro Services	Meter Reverification	Contract	5065	500	
Niagara Falls Hydro Services	Customer Premises	Contract	5075	6,000	
Niagara Falls Hydro Services	Metering Contractor	Contract	5175	1,000	
					7,500
Niagara On The Lake Hydro Inc	Hydro	Market Price	5675	5,000	
1					**5,000**

Oshawa Public Utilities	Metering Installation	Contract	5010	14,750	
					14,750
Peninsula Video & Sound	Locates	Contract	5075	30,000	
					30,000
Penner Building Centre	Line Supplies	Market Price/Less Discount	5025	600	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5055	300	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5075	500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5085	1,500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5120	500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5125	1,000	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5150	1,000	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5160	1,500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5675	4,000	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5035	500	
					11,400
Pineridge Tree Service	Tree trimming	Tender Approach	5135	70,000	
					70,000
Pitney Bowes Leasing	Mail Machine	Contract	5315	3,900	
					3,900
Pitney Works	Billing Supplies	Market Price/Less Discount	5315	650	
					650
Postage By Phone	Postage	Market Price	5315	34,000	
Postage By Phone	Postage	Market Price	5620	2,400	
					36,400
Provincial Janitorial	Office Cleaning	Contract	5675	9,600	
					9,600
Ravine Engineering	Scada Software Mtce	Hourly Rate	5010	1,000	
Ravine Engineering	Transformer St-York/NOTL DS	Hourly Rate	5014	4,000	
Ravine Engineering	Distribution Stns(Readings,Testing E	Hourly Rate	5016	5,000	
					10,000
Rogers	Pagers	Market Price	5015	500	
					500
Scout Services	Billing Supplies	Market Price/Less Discount	5315	7,700	
					7,700
Service Experts	Building Mtce	Market Price	5675	500	
					500
Shepherds Utility	Safety Items	Market Price	5025	3,000	
Shepherds Utility	Line Supplies	Market Price	5125	3,000	
					6,000
SPI	HUB Service	Contract	5315	4,885	
					4,885
Tiltran Services	Line Supplies	Contract	5125	2,000	
Tiltran Services	U/G Conductor	Contract	5150	5,000	
Tiltran Services	Mtce Transformer	Contract	5160	6,500	
					13,500
Town Of NOTL	Water	Market Price	5675	5,000	
					5,000
Utilities Standard	USF Membership	Contract	5025	5,000	
Utilities Standard Forum	Underground Conductor	Contract	5040	5,000	
1					**10,000**

Vendor To Be Selected	Line Supplies(water/oil sampling)	Market Price	5015	3,200	
Vendor To Be Selected	Phone, Data Line	Market Price	5015	6,250	
Vendor To Be Selected	Safety Clothing	Market Price	5065	200	
Vendor To Be Selected	Operations GIS/Mapping/Drafting	Hourly Rate	5085	14,000	
Vendor To Be Selected	Outside Consulting Co-op	Hourly Rate	5085	5,000	
Vendor To Be Selected	Line Supplies	Market Pirce	5125	2,000	
Vendor To Be Selected	Mtce O/H Conductor-Infrared Insp	Contract	5125	5,000	
Vendor To Be Selected	Line Supplies	Market Price	5150	1,000	
Vendor To Be Selected	Line Supplies	Market Price	5160	1,500	
Vendor To Be Selected	Community Relations	Market Price	5425	1,000	
Vendor To Be Selected	General Mgr Expenses	Market Price	5605	5,000	
Vendor To Be Selected	Safety Items	Market Price	5615	700	
Vendor To Be Selected	Admin Expenses-Outside Services	Hourly Rate	5630	1,500	
Vendor To Be Selected	Admin-Directors Exp	Market Price	5665	500	
Vendor To Be Selected	Line Supplies	Market Price	5675	3,000	
Vendor To Be Selected	Web Page Support	Hourly Rate	5675	500	
Vendor To Be Selected	Web Page Support	Hourly Rate	5675	500	
					50,850
Waterloo North Hydro	Load Dispatching	Contract	5010	14,750	
					14,750
Welland Hydro	Computer Mtce	Contract	5675	2,000	
					2,000
Wiens Underground Inst	Underground Conductor	Tender	5150	4,000	
Wiens Underground Inst	Line Supplies	Tender	5155	750	
Wiens Underground Inst	Underground Service	Tender	5155	15,500	
					20,250
Xerox	Copier Lease	Contract	5085	1,700	
Xerox	Copier Lease	Contract	5315	5,700	
Xerox	Copier Lease	Contract	5620	4,000	
					11,400
Grand Total 2008					**702,050**

NIAGARA ON THE LAKE HYDRO INC

PURCHASE OF SERVICES 2009

Name of Company	Activity	Pricing	OEB Account	$ Amount	
Abloy Canada Inc	Metering Supplies	Market Price	5175	1,000	
					1,000
AGO Industries	Safety Clothing	Market Price	5025	1,750	
AGO Industries	Safety Clothing	Market Price	5045	1,750	
					3,500
Alliance Security	Building Security	Contract	5675	2,000	
					2,000
American Casting	Meter Seals	Market Price	5065	250	
American Casting	Metering Supplies	Market Price	5175	1,000	
					1,250
Beatties Supplies	Line Supplies	Market Price/Less Discount	5085	791	
Beatties Supplies	Billing Supplies	Market Price/Less Discount	5315	4,500	
Beatties Supplies	Office Supplies	Market Price/Less Discount	5620	3,020	
					8,311
Bell Canada	Phone, Data Line	Market Price/Less Discount	5015	1,000	
Bell Canada	Phone Lines	Market Price/Less Discount	5085	3,485	
Bell Canada	Phone Billing	Market Price/Less Discount	5315	1,590	
Bell Canada	Phone Admin	Market Price/Less Discount	5620	2,000	
					8,075
Bell Mobility	Phone Lines	Market Price/Less Discount	5085	5,000	
Bell Mobility	General Mgr Expenses	Market Price/Less Discount	5605	500	
Bell Mobility	Phone Admin	Market Price/Less Discount	5620	560	
					6,060
Bell Pole Rental	O/H Rental	Contract	5095	18,800	
					18,800
Borden Ladner Garvais	Support Services	Hourly Rate	5630	33,333	
					33,333
Burlington Business Forms	Line Supplies	Market Price/Less Discount	5085	500	
Burlington Business Forms	Metering Reading Billing Supplies	Market Price/Less Discount	5310	400	
Burlington Business Forms	Billing Supplies	Market Price/Less Discount	5315	1,000	
					1,900
C.O.S Computer Solutions	Computer Mtce	Contract	5675	2,027	
					2,027
Canadian Door Doctor	Repairs	Hourly Rate/Materials	5675	2,500	
					2,500
Central Communications	Phone Lines	Contract	5085	2,100	
					2,100
CIBC	EFT Charges/Global Payment	Market Price/Less Discount	5320	6,200	
CIBC	EFT Charges	Market Price/Less Discount	5620	6,500	
					12,700
Cintas	Billing Supplies	Market Price/Less Discount	5315	550	
Cintas	Office Supplies	Market Price/Less Discount	5620	550	
					1,100
Cogeco Cable	Internet Lines	Market Price	5085	415	
Cogeco Cable	Internet Billing	Market Price	5315	450	
Cogeco Cable	Internet Admin	Market Price	5620	500	
					1,365
Collective Utility	Meter Reading	Contract	5310	35,750	
					35,750
Country Lawns	Snow Removal	Contract	5112	10,000	
Country Lawns	Snow Removal	Contract	5114	500	
Country Lawns	Snow Removal	Contract	5675	8,500	
					19,000
Crawford Smith & Swallow	Audit Fees	Contract	5630	20,380	
					20,380
Credit Bureau	Collection Charges	Market Price/Less Discount	5320	1,020	
					1,020
Drakar Eng/Commercial Equip	Safety Items Lines/Glove Testing	Contract	5025	2,000	
					2,000
E&USA Audit	Admin Expenses-Outside Services	Contract	5630	8,000	
					8,000

EDA	Training/Seminars	Market Price	5005	2,500	
EDA	Seminars/Expenses	Market Price	5305	1,020	
EDA	Seminars/Expenses	Market Price	5315	2,750	
EDA	Seminars/Expenses	Market Price	5605	1,530	
EDA	Seminars/Expenses	Market Price	5610	510	
EDA	Seminars/Expenses	Market Price	5615	600	
EDA	Membership Renewal	Contract	5665	12,800	
					21,710
Enbridge Gas	Heating	Market Price	5675	7,000	
					7,000
Enerconnect Inc	Interval Meter reading	Contract	5310	4,485	
					4,485
ESA Fee	Fees	Contract	5680	5,370	
					5,370
ESRI Computer Mtce	Computer Mtce-Scada Mtce	Contract	5675	4,277	
					4,277
EUSA	Training/Seminars-Mgmt	Contract	5005	2,500	
EUSA	Training/Seminars	Contract	5025	8,000	
EUSA	Training/Seminars	Contract	5045	2,500	
EUSA	Training/Seminars	Contract	5065	4,000	
					17,000
GAMS	Transformer Inspection	Contract	5035	2,000	
GAMS	Transformer Inspection	Contract	5055	1,500	
GAMS	Mtce O/H Services	Contract	5130	7,500	
GAMS	Transformer Inspection	Contract	5160	15,000	
					26,000
GMS	Health Benefits	Market Price/Less Discount	5645	11,000	
					11,000
Grafton	Transformer Inpsection	Contract	5160	10,000	
					10,000
Grand & Toy	Line Supplies	Market Price/Less Discount	5025	500	
Grand & Toy	Line Supplies	Market Price/Less Discount	5085	900	
Grand & Toy	Billing Supplies	Market Price/Less Discount	5315	2,700	
Grand & Toy	Office Supplies	Market Price/Less Discount	5620	2,780	
					6,880
Jim Neufeld	Safety Training	Hourly Rate	5025	750	
Jim Neufeld	Safety Training	Hourly Rate	5045	750	
Jim Neufeld	Safety Training	Hourly Rate	5065	500	
Jim Neufeld	Safety Training	Hourly Rate	5315	510	
Jim Neufeld	Safety Training	Hourly Rate	5615	320	
					2,830
Kinetiq Canada	Computer Mtce	Contract	5675	6,696	
					6,696
L St Amand	Screenings	Market Price	5120	500	
L St Amand	Screenings	Market Price	5675	1,000	
					1,500
Lancaster, Brooks & Welch	Legal Fees	Hourly Rate	5630	2,040	
					2,040
Mearie	Seminars/Expenses	Market Price/Less Discount	5610	510	
Mearie	Seminars/Expenses	Market Price/Less Discount	5615	600	
Mearie	Insurance/Liability Policy	Market Price/Less Discount	5640	27,700	
Mearie	Life & LTD Insurance	Market Price/Less Discount	5645	11,000	
Mearie Electric Association	Property Premium	Market Price/Less Discount	5635	20,600	
					60,410
Micro Tech Niagara	Computer Mtce	Hourly Rate	5675	32,000	
					32,000
Modern Landfill	Dump Fees	Market Price	5120	2,000	
Modern Landfill	Dump Fees	Market Price	5675	7,500	
					9,500
Niagara Analytical	Line Supplies(water/oil sampling)	Market Price	5015	2,000	
Niagara Analytical	PCB Analysis	Market Price	5160	5,000	
					7,000
Niagara Community Newspapers	Advertising	Market Price/Less Discount	5660	1,020	
					1,020
Niagara Falls Hydro Services	Meter Reverification	Contract	5065	500	
Niagara Falls Hydro Services	Customer Premises	Contract	5075	6,000	
Niagara Falls Hydro Services	Metering Contractor	Contract	5175	2,000	
1					**8,500**

Niagara On The Lake Hydro Inc	Hydro	Market Price	5675	5,000	
					5,000
Oshawa Public Utilities	Metering Installation	Contract	5010	14,750	
					14,750
Peninsula Video & Sound	Locates	Contract	5075	33,000	
					33,000
Penner Building Centre	Line Supplies	Market Price/Less Discount	5025	600	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5055	300	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5075	500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5085	1,500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5120	500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5125	1,000	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5150	1,000	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5160	2,500	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5675	4,475	
Penner Building Centre	Line Supplies	Market Price/Less Discount	5035	500	
					12,875
Pineridge Tree Service	Tree trimming	Tender	5135	85,000	
					85,000
Pitney Bowes Leasing	Mail Machine	Contract	5315	3,900	
					3,900
Pitney Works	Billing Supplies	Market Price/Less Discount	5315	650	
					650
Postage By Phone	Postage	Market Price	5315	34,650	
Postage By Phone	Postage	Market Price	5620	2,450	
					37,100
Provincial Janitorial	Office Cleaning	Contract	5675	9,780	
					9,780
Ravine Engineering	Scada Software Mtce	Hourly Rate	5010	1,000	
Ravine Engineering	Transformer St-York/NOTL DS	Hourly Rate	5014	4,000	
Ravine Engineering	Distribution Stns(Readings,Testing Et	Hourly Rate	5016	6,000	
					11,000
Rogers	Pagers	Market Price	5015	800	
					800
Scout Services	Billing Supplies	Market Price/Less Discount	5315	9,215	
					9,215
Service Experts	Building Mtce	Market Price	5675	500	
					500
Shepherds Utility	Safety Items	Market Price	5025	3,000	
Shepherds Utility	Line Supplies	Market Price	5125	3,000	
					6,000
SPI	HUB Service	Contract	5315	4,885	
					4,885
Tiltran Services	Line Supplies	Contract	5125	2,000	
Tiltran Services	U/G Conductor	Contract	5150	5,000	
Tiltran Services	Mtce Transformer	Contract	5160	15,000	
					22,000
Town Of NOTL	Water	Market Price	5675	5,000	
					5,000
Utilities Standard Forum	USF Membership	Contract	5025	5,000	
Utilities Standard Forum	Underground Conductor	Contract	5040	5,000	
1					**10,000**

Vendor To Be Selected	Line Supplies(water/oil sampling)	Market Price	5015	3,200	
Vendor To Be Selected	Phone, Data Line	Market Price	5015	6,250	
Vendor To Be Selected	Safety Clothing	Market Price	5065	200	
Vendor To Be Selected	Operations GIS/Mapping/Drafting	Hourly Rate	5085	14,000	
Vendor To Be Selected	Outside Consulting Co-op	Hourly Rate	5085	5,000	
Vendor To Be Selected	Line Supplies	Market Pirce	5125	2,000	
Vendor To Be Selected	Mtce O/H Conductor-Infrared Insp	Contract	5125	5,000	
Vendor To Be Selected	Line Supplies	Market Price	5150	1,000	
Vendor To Be Selected	Line Supplies	Market Price	5160	2,500	
Vendor To Be Selected	Community Relations	Market Price	5425	1,020	
Vendor To Be Selected	General Mgr Expenses	Market Price	5605	5,100	
Vendor To Be Selected	Safety Items	Market Price	5615	700	
Vendor To Be Selected	Admin Expenses-Outside Services	Hourly Rate	5630	1,530	
Vendor To Be Selected	Admin-Directors Exp	Market Price	5665	500	
Vendor To Be Selected	Line Supplies	Market Price	5675	3,000	
Vendor To Be Selected	Web Page Support	Hourly Rate	5675	510	
Vendor To Be Selected	Web Page Support	Hourly Rate	5675	510	
					52,020
Waterloo North Hydro	Load Dispatching	Contract	5010	14,750	
					14,750
Welland Hydro	Computer Mtce	Contract	5675	2,380	
					2,380
Wiens Underground Inst	Underground Conductor	Tender	5150	4,000	
Wiens Underground Inst	Line Supplies	Tender	5155	750	
Wiens Underground Inst	Underground Service	Tender	5155	15,500	
					20,250
Xerox	Copier Lease	Contract	5085	1,700	
Xerox	Copier Lease	Contract	5315	5,700	
Xerox	**Copier Lease**	**Contract**	**5620**	**3,570**	
					10,970
Grand Total 2009					**809,215**

EMPLOYEE DESCRIPTION, COMPENSATION AND PENSION

Note: *The 2006 Rate Handbook states the following: "Where there are three, or fewer, full-time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs". As NOTL Hydro has only one Executive, this employee has been included with Management in the data in this Schedule.*

Table 1

Summary of Employees and Compensation

NUMBERS OF EMPLOYEES					
Number of Employees (FTEs)	2006 Approved*	2006 (Actual)	2007 (Actual)	2008 (Bridge)	2009 (Test)
Management + Executive	5	5	5	5	5
Non-Union	0	0	0	1	1
Union	9	12	12	13	13
Total	14	17	17	19	19
	(2006 approved is 2004 data)*				
Number of Part Time Employees	2006 Approved*	2006	2007	2008	2009
Management + Executive	0	0	0	0	0
Non-Union	2	3	3	2	2
Union	0	0	0	0	0
Total	2	3	3	2	2
TOTAL COMPENSATION					
Total Compensation	2006 Approved*	2006	2007	2008	2009
Management + Executive	$ 467,659	$ 478,079	$ 513,878	$ 527,178	$ 548,999
Non-Union (includes part-time employees)	$ 60,764	$ 39,620	$ 56,986	$ 86,110	$ 87,698
Union	$ 584,933	$ 800,099	$ 810,704	$ 946,844	$ 945,182
Total Compensation	$ 1,113,356	$ 1,317,798	$ 1,381,568	$ 1,560,132	$ 1,581,879
COMPONENTS OF TOTAL COMPENSATION - AVERAGE PER EMPLOYEE					
	2006 Approved*	2006	2007	2008	2009
Total All Components (from above)	**$ 1,113,356**	**$ 1,317,798**	**$ 1,381,568**	**$ 1,560,132**	**$ 1,581,879**
Total Base Wages Component	$ 835,085	$ 961,187	$ 1,035,966	$ 1,187,713	$ 1,207,769
Average per Employee					
Management + Executive	$ 68,727	$ 70,177	$ 75,439	$ 79,500	$ 83,077
Non-Union (includes part-time employees)	$ 27,678	$ 11,927	$ 17,321	$ 24,222	$ 24,690
Union	$ 48,455	$ 47,877	$ 50,567	$ 55,196	$ 55,255
	2006 Approved*	2006	2007	2008	2009
Total Overtime Component	$ 54,177	$ 95,751	$ 65,895	$ 53,226	$ 52,940
Average per Employee					
Management + Executive	$ 3,068	$ 3,118	$ 3,093	$ 1,522	$ 1,590
Non-Union (includes part-time employees)	$ 45	$ -	$ -	$ -	$ -
Union	$ 4,305	$ 6,680	$ 4,203	$ 3,509	$ 3,461
	2006 Approved*	2006	2007	2008	2009
Total Incentive Component	$ 31,925	$ 32,565	$ 35,676	$ 37,168	$ 38,684
Average per Employee					
Management + Executive	$ 6,040	$ 5,892	$ 6,505	$ 6,734	$ 7,037
Non-Union (includes part-time employees)	$ 38	$ -	$ -	$ -	$ -
Union	$ 183	$ 259	$ 263	$ 269	$ 269
	2006 Approved*	2006	2007	2008	2009
Total Benefits Component	$ 192,169	$ 228,295	$ 244,031	$ 282,024	$ 282,487
Average per Employee					
Management + Executive	$ 15,697	$ 16,165	$ 17,739	$ 17,681	$ 18,096
Non-Union (includes part-time employees)	$ 2,622	$ 1,279	$ 1,675	$ 4,482	$ 4,542
Union	$ 12,549	$ 11,601	$ 12,526	$ 13,860	$ 13,722
COMPENSATION CHARGED TO OM&A					
	2006 Approved*	2006	2007	2008	2009
Total Compensation	$ 1,113,356	$ 1,317,798	$ 1,381,568	$ 1,560,132	$ 1,581,879
less: capitalized	$ 318,371	$ 374,254	$ 244,162	-$ 531,019.99	-$ 545,366.33
less: billable	$ 61,818	$ 142,935	$ 125,925	-$ 162,144.65	-$ 170,641.07
Compensation charged to OM&A	$ 733,166	$ 800,609	$ 1,011,480	$ 866,967	$ 865,872
Compensation Charged to OM&A by employee group					
	2006 Approved*	2006	2007	2008	2009
Management + Executive	$ 344,435	$ 309,974	$ 401,102.52	$ 382,100	$ 391,120
Non-Union (includes part-time employees)	$ 55,871	$ 35,794	$ 55,639.90	$ 76,440	$ 77,862
Union	$ 332,861	$ 454,841	$ 554,738.03	$ 408,427	$ 396,891
Compensation charged to OM&A	$ 733,166	$ 800,609	$ 1,011,480	$ 868,975	$ 867,881

Incentive Plan Amounts

The incentive plan amounts in Table 1 above refer to NOTL Hydro's senior management bonus plan and employee sick time incentive.

- *Senior Management Bonus Plan*

Senior management employees of Niagara-on-the-Lake Hydro, comprised of the President, Director of Corporate Services and Operations Manager, are compensated by a combination of salary and performance bonus. These bonuses range from a maximum of 10% to 20% of salary with the actual bonus amount determined through assessment of predetermined performance targets.

Generally, 50% of the bonus is determined by ensured compliance with all regulations and achieving financial targets, 25% for efficient planning and 25% for leadership.

Compliance includes meeting all O.E.B., O.E.F.C., ESA and IESO requirements of a market participant as well as environmental and business legal requirements of an OBCA company. Both capital and operating budgets must be maintained to achieve net income financial goals. We believe that ensuring full compliance with all industry regulatory requirements while maintaining budgets and meeting financial goals drives efficiencies in the company. The true beneficiary of this system is our customer through lower distribution rates and efficiently delivered services.

Efficient planning requires the effective use of staff and external resources and the development of.shared services and mutual assistance relationships primarily with neighbouring LDC’s that result in improved quality of our business and service levels. The customer is the beneficiary of higher quality service levels as a result.

The leadership target involves the promotion of public awareness of electrical safety and conservation in our community. It also requires the teambuilding and motivation of staff to achieve high performance levels and the participation in provincial industry working groups and associations that may help shape the future electricity market. In our view, this type of leadership benefits our customers and community as a whole.

- *Employee Sick Time Incentive*

A program that provided a bonus to employees for perfect attendance was implemented for the first time in 2003. The program provides a quarterly bonus ($85 gift) for perfect attendance but allows for medical appointments that are scheduled early or late in the day as to not disrupt crews and daily work assignments. As a result, attendance has improved and most medical appointments have been shifted. The resulting efficiencies improve customer service response by ensuring that a full complement of staff is always available to assist the customer. We strongly feel that the added employee hours on the job directly benefit the customer.

Pension funding

NOTL Hydro and its employees are members of the Ontario Municipal Employees Retirement System ("OMERS") pension plan. Accordingly, NOTL Hydro has provided the OMERS pension premium information for the 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year in Table 2 below.

Table 2
Pension Premium Information

Pension	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Pension Premiums	$ 68,150	$ 71,076	$ 82,250	$ 81,522
Less: Billable	-$ 7,362	-$ 6,455	-$ 11,100	-$ 11,399
Less: Capitalized	-$ 18,968	-$ 12,516	-$ 27,870	-$ 27,804
Amount Expensed to OM&A	$ 41,820	$ 52,104	$ 43,281	$ 42,319

Post Retirement Benefits

NOTL Hydro engages a consultant every 3 years to perform an actuarial valuation of the post retirement non-pension benefits sponsored by NOTL Hydro. The last actuarial was done as of December 31, 2006. NOTL Hydro has provided the post-retirement benefits cost for the 2006 Actual, 2007 Actual, 2008 Bridge Year and the 2009 Test Year in Table 3 below.

Table 5
Post-Retirement Benefit Information

	2006 Actual	2007 Actual	2008 Bridge	2009 Test
Post Retirement Benefits				
Post-Retirement Benefits Cost	$ 23,967	$ 19,471	$ 22,000	$ 22,000
Less: Billable	$ -	$ -	$ -	$ -
Less: Capitalized	$ -	$ -	$ -	$ -
Amount Expensed to OM&A	$ 23,967	$ 19,471	$ 22,000	$ 22,000

DEPRECIATION, AMORTIZATION AND DEPLETION:

Amortization on capital assets is calculated as follows:

- Amortization calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus:
- Amortization on capital additions during the current year – half-year rule is applied.

Appendix B – “Amortization Rates” – of the 2006 Electricity Distribution Rate Handbook (“EDRH”) provides rates based on the straight-line method of amortization.

Details of NOTL Hydro’s amortization (depreciation) by asset group are provided in the Table 1 below. Please note that the expense amounts shown reflect depreciation expenses only and as such do not include effect of disposals on accumulated depreciation on the balance sheet. However, asset amounts shown are year-end totals after disposals, consistent with the asset continuity tables in **Exhibit 2, Tab 2, Schedule 1.**

Table 1
Depreciation

Description	2006 Board Approved Assets ($)	Depreciation Expense	2006 Actual Assets ($)	Depreciation Expense	2007 Actual Assets ($)	Depreciation Expense	2008 Bridge Assets ($)	Depreciation Expense	2009 Test Assets ($)	Depreciation Expense	Amortization Period (Years)
Land and Buildings											
1805-Land	198,798		261,994		261,994		261,994		301,994		
1806-Land Rights											
1808-Buildings and Fixtures											
1905-Land	49,000		49,000		49,000		49,000		49,000		
1906-Land Rights											
1810-Leasehold Improvements											
Sub-Total-Land and Buildings	**247,798**		**310,994**		**310,994**		**310,994**		**350,994**		
TS Primary Above 50											
1815-Transformer Station Equipment - Normally Primary above 50 kV	3,772,989	119,360	4,996,118	122,660	5,181,654	127,222	5,311,654	131,166	5,316,654	132,854	40
Sub-Total-TS Primary Above 50	**3,772,989**	**119,360**	**4,996,118**	**122,660**	**5,181,654**	**127,222**	**5,311,654**	**131,166**	**5,316,654**	**132,854**	
DS											
1820-Distribution Station Equipment - Normally Primary below 50 kV	263,416	6,082	242,132	5,670	242,132	5,670	270,452	(13,498)	270,452	3,141	30
Sub-Total-DS	**263,416**	**6,082**	**242,132**	**5,670**	**242,132**	**5,670**	**270,452**	**(13,498)**	**270,452**	**3,141**	
Poles and Wires											
1830-Poles, Towers and Fixtures	3,783,277	99,778	4,200,601	130,216	4,263,018	134,464	4,363,730	134,725	4,475,396	134,930	25
1835-Overhead Conductors and Devices	4,867,178	172,907	5,518,153	173,000	5,729,536	181,073	6,042,216	187,885	6,376,382	195,881	25
1840-Underground Conduit	2,875,314	112,807	3,596,713	131,290	3,687,229	141,942	3,927,229	148,552	4,636,395	167,535	25
1845-Underground Conductors and Devices	6,173,558	242,015	6,970,580	260,378	7,088,280	273,041	7,339,730	280,424	7,746,396	293,586	25
Sub-Total-Poles and Wires	**17,699,327**	**627,507**	**20,286,047**	**694,884**	**20,768,063**	**730,520**	**21,672,905**	**751,586**	**23,234,569**	**791,932**	
Line Transformers											
1850-Line Transformers	5,435,678	211,306	6,393,146	192,960	6,671,557	211,607	6,814,715	238,370	6,995,547	244,850	25
Sub-Total-Line Transformers	**5,435,678**	**211,306**	**6,393,146**	**192,960**	**6,671,557**	**211,607**	**6,814,715**	**238,370**	**6,995,547**	**244,850**	
Services and Meters											
1855-Services	1,026,410	43,056	1,624,200	60,206	1,867,773	69,839	1,967,773	76,711	2,067,773	80,711	25
1860-Meters	910,741	31,717	1,032,961	32,744	1,039,529	26,111	1,059,529	36,975	1,079,529	37,774	25
1861-Smart Meters											
Sub-Total-Services and Meters	**1,937,151**	**74,772**	**2,657,161**	**92,950**	**2,907,301**	**95,951**	**3,027,301**	**113,686**	**3,147,301**	**118,485**	
General Plant											
1908-Buildings and Fixtures	845,593	14,530	867,344	14,885	909,794	15,394	934,794	16,068	954,794	16,518	50
1910-Leasehold Improvements											
Sub-Total-General Plant	**845,593**	**14,530**	**867,344**	**14,885**	**909,794**	**15,394**	**934,794**	**16,068**	**954,794**	**16,518**	
IT Assets											
1920-Computer Equipment - Hardware	233,324	18,535	233,047	9,843	233,047	6,101	233,047	3,676	233,047	625	5
1921-Computer Equipment - Hardware post March 22, 2004			38,938	6,341	60,214	9,915	75,214	13,543	85,214	15,362	3
1925-Computer Software	501,482	84,874	824,767	194,120	891,659	139,345	941,659	76,903	991,659	63,017	3
Sub-Total-IT Assets	**734,806**	**103,409**	**1,096,752**	**210,303**	**1,184,920**	**155,361**	**1,249,920**	**94,121**	**1,309,920**	**79,004**	
Equipment											* 8 for trucks.3 tons
1915-Office Furniture and Equipment	134,769	3,699	163,168	4,376	169,151	5,146	174,151	5,695	179,151	6,111	10
1930-Transportation Equipment	1,004,612		967,850	26,365	945,199	(208,169)	975,199	83,532	975,199	86,361	5*
1935-Stores Equipment	14,235		14,235	171	16,039	261	18,039	284	38,039	1,384	10
1940-Tools, Shop and Garage Equipment	342,079	25,261	375,744	25,072	409,946	27,111	414,946	28,575	419,946	28,191	10
1945-Measurement and Testing Equipment											
1950-Power Operated Equipment											
1955-Communication Equipment	14,428	35	36,768	2,269	36,768	2,269	36,768	2,269	36,768	2,269	10
1960-Miscellaneous Equipment											
Sub-Total-Equipment	**1,510,124**	**28,994**	**1,557,766**	**58,253**	**1,577,103**	**(173,383)**	**1,619,103**	**120,354**	**1,649,103**	**124,315**	
Other Distribution Assets											
1825-Storage Battery Equipment											
1970-Load Management Controls - Customer Premises											
1975-Load Management Controls - Utility Premises											
1980-System Supervisory Equipment	159,922	10,664	302,743	19,527	315,463	20,607	325,463	21,364	335,463	22,031	15
1985-Sentinel Lighting Rental Units											
1990-Other Tangible Property											
1995-Contributions and Grants - Credit	(2,802,684)	(112,674)	(4,522,868)	(161,510)	(4,827,565)	(187,575)	(4,977,565)	(196,200)	(5,127,565)	(201,454)	25
1996-Hydro One S/S Contribution											
Sub-Total-Other Distribution Assets	**(2,642,762)**	**(102,010)**	**(4,220,126)**	**(141,983)**	**(4,512,101)**	**(166,968)**	**(4,652,101)**	**(174,836)**	**(4,792,101)**	**(179,423)**	
GROSS ASSET TOTAL	**29,804,120**	**1,083,952**	**34,187,333**	**1,250,581**	**35,241,416**	**1,001,373**	**36,559,736**	**1,277,019**	**38,437,232**	**1,331,677**	

LOSS ADJUSTMENT FACTOR CALCULATION:

- **Total Loss Factor:**

NOTL Hydro has calculated the total loss factor for customers' consumption based on the wholesale and retail kWh for the years 2003 to 2007. The calculations are summarized in Table 1 below.

Table 1
Total Loss Factor Calculations

Calculation for distribution loss adjustment factors

	Description	2003	2004	2005	2006	2007	5-Year Total
A	"Wholesale" kWh IESO plus Embedded Generation	174,477,589	178,152,405	188,569,914	182,453,427	188,506,590	912,159,925
B	"Wholesale" kWh for Large Use customer(s)	0	0	0	0	0	0
C	Net "Wholesale" kWh (A)-(B)	174,477,589	178,152,405	188,569,914	182,453,427	188,506,590	912,159,925
D	"Retail" kWh (Distributor)	166,270,246	169,788,483	179,968,717	175,258,855	180,475,098	871,761,398
E	"Retail" kWh for Large Use Customer(s)	0	0	0	0	0	0
F	Net "Retail" kWh (D)-(E)	166,270,246	169,788,483	179,968,717	175,258,855	180,475,098	871,761,398
G	Loss Factor [(C)/(F)]	1.0494	1.0493	1.0478	1.0411	1.0445	**1.0463**
H	Total Loss Adjustment Factor (5 year avg.)					**Proposed no change**	**1.0501**
	Supply Facility Loss Factor	1.0060	1.0060	1.0058	1.0046	1.0052	1.0055
	Supply Facility Loss Adjustment Factor (3 year avg.)						**1.0055**

The average total loss factor for the period from 2003 to 2007 is calculated as 1.0463. However, NOTL Hydro is proposing to leave the current OEB approved loss factor of 1.0501 unchanged at this time due to the remaining debit balance in the power purchase variance account (Account 1588) of $264,801 at December 31, 2007. NOTL Hydro intends to approach the OEB with a proposed reduction of the total loss factor at a future rate submission when the debit balance is reduced or eliminated.

- **Supply Facility Loss Factor:**

The supply facility loss factor (the "SFLF") is calculated in Table 2 and represents the losses on supply to NOTL Hydro. The SFLF is calculated on the measured quantities between the transformer stations and the wholesale meter points. The SFLF is used in the calculations of the total loss factor above.

Table 2

Table 2
Supply Facility Loss Factor

Description	Full Year 2003	Full Year 2004	Full Year 2005	Full Year 2006	Full Year 2007	5-Year Total
"Wholesale" kWh IMO With Losses	174,477,589	178,152,405	188,569,914	182,453,427	188,506,590	912,159,925
"Wholesale" kWh IMO No Losses	173,436,967	177,089,866	187,474,680	181,612,384	187,524,616	907,138,513
Supply Facility Loss Factor	0.00600	0.00600	0.00584	0.00463	0.00524	0.00554

- **Total Loss Factor by Class:**

Table 3 sets out the class-specific Loss Factors used by NOTL Hydro in the calculation of commodity and other non-distribution charges.

Table 3
Total Loss Factor by Class

Loss Factors	
Supply Facility Loss Factor	1.0055
Distribution Loss Factor - Secondary Metered Customer < 5,000kW	1.0443
Distribution Loss Factor - Secondary Metered Customer > 5,000kW	1.0100
Distribution Loss Factor - Primary Metered Customer < 5,000kW	1.0339
Distribution Loss Factor - Primary Metered Customer > 5,000kW	1.0000
For Tariff of Rates and Charges	
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0501
Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0156
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0396
Total Loss Factor - Primary Metered Customer > 5,000kW	1.0055

Materiality Analysis on Distribution Losses:

From the Table 3 in Exhibit 4, Tab 2, Schedule 7, NOTL Hydro's proposed distribution loss factor is 1.0443 , within a total loss factor of 1.0501 .

Pursuant to the Filing Requirements, as the distribution Loss Factor represents less than 5% losses, NOTL Hydro is not required to provide an explanation of, or justification for, its distribution loss adjustment factor.

TAX CALCULATIONS:

NOTL Hydro's detailed tax calculations are provided in the following Table 1.

Table 1
Tax Calculations

Description	2006 Board Approved	2008 Bridge	2009 Test
Determination of Taxable Income			
Utility Income Before Taxes	889,437	1,102,198	1,218,343
Book to Tax Adjustments			
Additions to Accounting Income:			
Depreciation and amortization	1,085,204	1,295,272	1,331,677
Interest and penalties on taxes	1,894		
Income or Loss for tax Purposes-joint ventures or partnerships		0	0
Employee Benefit Plans - accrued, not paid	15,414		
Meals & entertainment / Mileage		0	0
Non-deductible club fees and dues		0	0
Taxable Capital Gains		0	0
Tax reserves beginning of year		0	0
Reserves from financial statements -balance at year end		0	0
Change in regulatory assets		48,161	17,723
Change in employee future benefits		1,000	1,000
Total Additions	**1,102,512**	**1,344,433**	**1,350,400**
Deductions from Accounting Income:			
Capital Cost Allowance	1,204,489	1,212,678	1,235,844
Excess Interest Expense for 2006 PILs	90,096		
Gain on disposal of assets per financial statements		0	0
Cumulative eligible capital deduction	1,321	1,063	988
Tax reserves end of year		0	0
Reserves from financial statements balance at beginning of year		0	0
Other deductions		85,218	86,361
ITC Booked in Accounting Income			0
Total Deductions	**1,295,907**	**1,298,959**	**1,323,194**
Regulatory Taxable Income	**696,042**	**1,147,672**	**1,245,550**
Corporate Income Tax Rate	29.60%	33.50%	33.00%
Subtotal	**206,062**		
Less: R&D ITC (0.3)			
Regulatory Income Tax	**206,062**	**384,470**	**411,031**
Calculation of Utility Income Taxes			
Income Taxes	206,062	384,470	411,031
Large Corporation Tax	0	0	0
Ontario Capital Tax	29,296	18,882	15,166
Total Taxes	**235,358**	**403,352**	**426,198**

Table 1

cont'd

Tax Rates			
Federal Tax	22.12%	19.50%	19.00%
Federal Surtax			
Provincial Tax	7.48%	14.00%	14.00%
Total Tax Rate	**29.60%**	**33.50%**	**33.00%**

Calculation of Large Corporation Tax			
Total Rate Base	19,765,266	21,625,118	21,740,616
Less: Exemption	50,000,000		
Taxable Capital	**0**		
LCT Rate	0.125%	0.125%	0.125%
Subtotal	0	0	0
Federal Surtax	0	0	0
Large Corporation Tax	**0**	**0**	**0**

Calculation of Ontario Capital Tax			
Total Rate Base	19,765,266	21,625,118	21,740,616
Less Exemption	10,000,000	15,000,000	15,000,000
Taxable Capital /Deemed taxable capital	**9,765,266**	**6,625,118**	**6,740,616**
OCT Rate	0.300%	0.285%	0.225%
Ontario Capital Tax	**29,296**	**18,882**	**15,166**

Summary of Income Taxes

Description	**2006 Board Approved**	**2007 Bridge**	**2009 Test**
Income Taxes	206,062	384,470	411,031
Large Corporation Tax	0	0	0
Ontario Capital Tax	29,296	18,882	15,166
Total Taxes	**235,358**	**403,352**	**426,198**

INTEREST EXPENSE

NOTL Hydro has calculated interest expense in accordance with the Filing Requirements as shown in the Capital Structure table in **Exhibit 6, Tab 1, Schedule 2**.

Table 1 below summarizes the calculated deemed interest expenses from the capital structure table:

Table 1
Deemed Interest Expense $

Debt	2,006	2,007	2,008	2,009
Long Term	727,477	721,424	777,292	775,463
Short Term				38,872
Total	727,477	721,424	777,292	814,335

CAPITAL COST ALLOWANCE:

NOTL Hydro is providing Capital Cost Allowance continuity schedules for the 2008 Bridge Year and the 2009 Test Year on the following two pages.

2008 Bridge Year

CCA Continuity Schedule (2008)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
4														
5	Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
6	1	Distribution System - 1988 to 22-Feb-2005	12,344,578	0	-888,880	13,233,458	0	5000	13,228,458	0	13,228,458	4%	529,138	12,699,320
7	2	Distribution System - pre 1988	4,564,587	0	3,412,751	1,151,836	0	0	1,151,836	0	1,151,836	6%	69,110	1,082,726
8	6	Buildings (No footings below ground)	6,217	0	6,217	0	0	0	0	0	0	10%	0	0
9	8	General Office/Stores Equip	232,077	0	59,208	172,869	12,000	0	184,869	6,000	178,869	20%	35,774	149,095
10	10	Computer Hardware/ Vehicles	294,933	0	17,346	277,587	30,000	0	307,587	15,000	292,587	30%	87,776	219,811
11	10.1	Certain Automobiles		0	0	0	0	0	0	0	0	30%	0	0
12	12	Computer Software	33,446	0	0	33,446	50,000	0	83,446	25,000	58,446	100%	58,446	25,000
13	13 1	Lease # 1		0	0	0	-	0	0	0	0	20%	0	0
14	13 2	Lease #2		0	0	0	0	0	0	0	0		0	0
15	13 3	Lease # 3		0	0	0	0	0	0	0	0		0	0
16	13 4	Lease # 4		0	0	0	0	0	0	0	0		0	0
17	14	Franchise		0	0	0	0	0	0	0	0		0	0
18	17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	38,353	0	20,200	18,153	0	0	18,153	0	18,153	8%	1,452	16,701
19	43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	0	0	30%	0	0
20	45	Computers & Systems Hardware acq'd post Mar 22/04	11,186	0	0	11,186	0	0	11,186	0	11,186	45%	5,034	6,152
21	45.1	Computers & Systems Hardware acq'd post Mar 19/07	15,424	0	0	15,424	15,000	0	30,424	7,500	22,924	55%	12,608	17,816
22	46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	0	0	0	30%	0	0
23	47	Distribution System - post 22-Feb-2005	4,575,249			4,575,249	1,183,000		5,758,249	591,500	5,166,749	8%	413,340	5,344,909
24		**SUB-TOTAL - UCC**	**22,116,050**	**0**	**2,626,842**	**19,489,208**	**1,290,000**	**5,000**	**20,774,208**	**645,000**	**20,129,208**		**1,212,678**	**19,561,530**
25														
26	CEC	Incorporation costs	15,184	0	0	15,184								
27	CEC	Land Rights		0	0	0								
28	CEC	FMV Bump-up		0	0	0								
29		**SUB-TOTAL - CEC**	**15,184**	**0**	**0**	**15,184**								
30														

Cumulative Eligible Capital Calculation

		E	F	G	H
31					
32					
33	Cumulative Eligible Capital				15,184
34					
35	Additions:				
36	Cost of Eligible Capital Property Acquired during the year	0			
37					
38	Other Adjustments	0			
39					
40	Subtotal	0	x 3/4 =	0	
41					
42	Non-taxable portion of a non-arm's length transferor's gain realized on the				
43	transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
44				0	15,184
45					
46	Amount transferred on amalgamation or wind-up of subsidiary	0			0
47					
48	Subtotal				15,184
49					
50	Deductions:				
51					
52	Projected proceeds of sale (less outlays and expenses not otherwise				
53	deductible) from the disposition of all ECP during the year				
54					
55	Other Adjustments	0			
56					
57	Subtotal	0	x 3/4 =	0	15,184
58					
59					
60					
61	Cumulative Eligible Capital Balance				15,184
62					
63	CEC Deduction	7%			1,063
64					
65	Cumulative Eligible Capital - Closing Balance				14,121
66					

2009Test Year

CCA Continuity Schedule (2009)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
5	Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
6	1	Distribution System - 1988 to 22-Feb-2005	12,699,320	0	0	12,699,320	0	0	12,699,320	0	12,699,320	4%	507,973	12,191,347
7	2	Distribution System - pre 1988	1,082,726	0	0	1,082,726	0	0	1,082,726	0	1,082,726	6%	64,964	1,017,762
8	6	Buildings (No footings below ground)	0	0	0	0	0	0	0	0	0	10%	0	0
9	8	General Office/Stores Equip	149,095	0	0	149,095	30,000	0	179,095	15,000	164,095	20%	32,819	146,276
10	10	Computer Hardware/ Vehicles	219,811	0	0	219,811	0	0	219,811	0	219,811	30%	65,943	153,868
11	10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	12	Computer Software	25,000	0	0	25,000	50,000	0	75,000	25,000	50,000	100%	50,000	25,000
13	13 1	Lease # 1	0	0	0	0	-	0	0	0	0	20%	0	0
14	13 2	Lease #2	0	0	0	0	0	0	0	0	0		0	0
15	13 3	Lease # 3	0	0	0	0	0	0	0	0	0		0	0
16	13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
17	14	Franchise	0	0	0	0	0	0	0	0	0		0	0
18	17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	16,701	0	0	16,701	0	0	16,701	0	16,701	8%	1,336	15,365
19	43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
20	45	Computers & Systems Hardware acq'd post Mar 22/04	6,152	0	0	6,152	0	0	6,152	0	6,152	45%	2,769	3,384
21	45.1	Computers & Systems Hardware acq'd post Mar 19/07	17,816	0	0	17,816	10,000	0	27,816	5,000	22,816	55%	12,549	15,267
22	46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
23	47	Distribution System - post 22-Feb-2005	5,344,909			5,344,909	1,747,496	0	7,092,405	873,748	6,218,657	8%	497,493	6,594,913
24		**SUB-TOTAL - UCC**	**19,561,530**	**0**	**0**	**19,561,530**	**1,837,496**	**0**	**21,399,026**	**918,748**	**20,480,278**		**1,235,844**	**20,163,181**
25														
26	CEC	Incorporation costs	14,121	0	0	14,121								
27	CEC	Land Rights	0	0	0	0								
28	CEC	FMV Bump-up	0	0	0	0								
29		**SUB-TOTAL - CEC**	**14,121**	**0**	**0**	**14,121**								

Cumulative Eligible Capital Calculation

		E	F	G	H
33	Cumulative Eligible Capital				14,121
35	<u>Additions:</u>				
36	Cost of Eligible Capital Property Acquired during the year	0			
38	Other Adjustments	0			
40	Subtotal	0	x 3/4 =	0	
42	Non-taxable portion of a non-arm's length transferor's gain realized on the				
43	transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
44				0	14,121
46	Amount transferred on amalgamation or wind-up of subsidiary	0			0
48	Subtotal				14,121
50	<u>Deductions:</u>				
52	Projected proceeds of sale (less outlays and expenses not otherwise				
53	deductible) from the disposition of all ECP during the year				
55	Other Adjustments	0			
57	Subtotal	0	x 3/4 =	0	14,121
61	Cumulative Eligible Capital Balance				14,121
63	CEC Deduction	7%			988
65	Cumulative Eligible Capital - Closing Balance				13,133

INDEX FOR EXHIBIT 5

CALCULATION OF DVA BALANCES FOR DISPOSITION

NOTL Hydro uses Deferral and Variance ("DVA") accounts in a manner consistent with the definitions in the OEB Accounting Procedures Handbook.

The following Table 1 shows the audited balances of the DVA accounts, including principal and interest, as of December 31, 2007, for those accounts for which NOTL Hydro is requesting recovery at this time.

These accounts are:

1508 Other Regulatory Assets

Description: This account includes amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the Board:

Sub-account OEB Cost Assessments

Description: This account includes amounts paid for OEB Cost Assessment for the period January 1, 2004 to April 30, 2006 in excess of amounts previously included in rates (1999 OEB costs).

Sub-account Pension Contributions

Description: This account records the pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings ("OMERS") for the period from January 1, 2005 to April 30, 2006.

1550 Low Voltage Variance Account

Description: This account is used to record the amounts charged to NOTL Hydro by Hydro One for use of the shared LV line from the Hydro One-owned Stanley Transformer Station. The amounts charged are for the period May 2006 to July 2007. As of January 1, 2007, NOTL Hydro intentionally chose not to utilize the Stanley TS supply point, negating the monthly per kW charge as of July 2007.

Interest from January 1, 2008 to April 30, 2009 is also projected at the currently known OEB-prescribed interest rates or forecast rates where the prescribed rate is not yet announced.

Table 1

Account Description	Account Number	Principal Amounts as of Dec-31 2007	Interest to Dec31-07	Interest Jan-1 to Dec31-08	Interest Jan1-09 to Apr30-09	Total Claim
Other Regulatory Assets	1508	$ 95,568	$ 9,665	$ 3,804	$ 1,067	$ 110,104
Low Voltage	1550	$ 18,804	$ 1,163	$ 748	$ 210	$ 20,926
Totals per column		$ 114,372	$ 10,828	$ 4,552	$ 1,277	$ 131,030

	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Jan to Apr 2009
rate:	5.14%	4.08%	3.35%	3.35%	3.35%

NOTL Hydro is not requesting disposition at this time for balances in RSVA and RCVA accounts (accounts 1580, 1582, 1584, 1586, 1588, 1518 and 1548), as the OEB has stated in decisions on 2008 rate rebasing applications that "*The Board is of the view that it is appropriate to defer the disposition of the RCVA and RSVA accounts until the completion of the announced generic review of these accounts*".

NOTL Hydro is not requesting disposition at this time for remaining PILs account (account 1562) balances, as the OEB has stated in decisions on 2008 rate rebasing applications that "*The Board will not dispose of this account as part of this proceeding. The Board, by letter dated March 3, 2008, has announced that it will initiate a combined proceeding to determine the methodology that should be used for the calculation and disposition of account 1562*".

NOTL Hydro is not requesting disposition at this time for Smart Meter accounts (accounts 1555 and 1556), as NOTL Hydro's installation of Smart Meters has not yet begun. Rather, an increased rate rider is proposed as of May 1, 2009, as explained in **Exhibit 9, Tab 1, Schedule 1**.

NOTL Hydro is not requesting any disposition at this time related to the regulatory asset recovery account (account 1590) as any residual balance as of April 30, 2008 will not be audited until the Spring of 2009.

Balances of all other DVA accounts as of December 31, 2007 were zero and therefore do not require disposition.

METHODS OF DISPOSITION OF DVA BALANCES:

The methods proposed to dispose of the DVA balances, together with a summary of proposed rates and bill impacts, are set out in this Schedule.

Disposal of principal balances as at December 31, 2007 and projected interest to April 30, 2009 is requested over a 3 -year period.

NOTL Hydro considered recovery periods of 1, 2 or 3 years. Because rate riders are normally rounded to 4 decimal places in rate orders, the calculations result in an over-recovery of $4,849 with a 2 year recovery period. The over- or under- recovery amounts at 1 year and 3 year recovery would be relatively small. A 3 year recovery period is proposed to minimize monthly bill impacts while avoiding significant over-recovery.

Method of Recovery:

1508 Other Regulatory Assets

Method of recovery: Allocation to rate classes on basis of distribution revenue in 2007.

1550 Low Voltage Variance Account

Method of recovery: Allocation to rate classes on basis of kWh consumed in 2007.

Calculation of Allocators:

The calculation of allocators is shown in Table 1 below:

Table 1
Allocators

2007 Data By Class	kWhs	Dx Revenue
RESIDENTIAL CLASS	65,499,951	$ 2,165,327
GENERAL SERVICE <50 KW CLASS	34,969,161	$ 1,048,489
GENERAL SERVICE >50 KW NON TIME OF	78,684,896	$ 1,221,004
UNMETERED & SCATTERED LOADS	217,931	$ 120,529
STREET LIGHTING	1,002,185	$ 42,013
	101,689,228	3,376,359

Allocators	kWhs	Dx Revenue
RESIDENTIAL CLASS	36.3%	47.1%
GENERAL SERVICE <50 KW CLASS	19.4%	22.8%
GENERAL SERVICE >50 KW NON TIME OF	43.6%	26.6%
UNMETERED & SCATTERED LOADS	0.1%	2.6%
STREET LIGHTING	0.6%	0.9%
Totals	100%	100%

Calculation of Rate Riders

Based on the above allocators, the proposed rate rider calculations are shown in Table 2 below:

Table 2
Proposed Rate Riders

Deferral and Variance Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	Scattered Load	Street Lighting	Total
Other Regulatory Assets - Account 1508	$ 110,104	Dx Revenue	$ 51,858	$ 25,111	$ 29,242	$ 2,887	$ 1,006	$ 110,104
Low Voltage - Account 1550	$ 20,926	kWh	$ 7,599	$ 4,057	$ 9,128	$ 25	$ 116	$ 20,926
Total to be Recovered	$ 131,030		$ 59,457	$ 29,168	$ 38,371	$ 2,912	$ 1,122	$ 131,030
Balance to be collected or refunded, Variable	$ 131,030		$ 59,457	$ 29,168	$ 38,371	$ 2,912	$ 1,122	$ 131,030
Balance to be collected or refunded, Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -
Number of years for Variable 3								
Balance to be collected or refunded per year, Variable	$ 43,677		$ 19,819	$ 9,723	$ 12,790	$ 971	$ 374	$ 43,677
Balance to be collected or refunded per year, Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -

Class	Residential	GS < 50 KW	GS > 50 Non TOU	Scattered Load	Street Lighting
Proposed Rate Riders, Variable	**$ 0.0003**	**$ 0.0003**	**$ 0.0629**	**$ 0.0045**	**$ 0.1291**
Billing Determinants	kWh	kWh	kW	kWh	kW

Bill Impacts:

The bill impacts that result from the disposal of the DVA balances depend on the total bill and are set out in **Exhibit 9, Tab 1, Schedule 9**.

INDEX FOR EXHIBIT 6

OVERVIEW:

The purpose of this evidence is to summarize the method and cost of financing NOTL Hydro's capital requirements for the 2009 test years and to support the rate of return on rate base of 7.46% as shown in **Exhibit 6, Tab 1, Schedule 2**.

Capital Structure:

NOTL Hydro has a current (2008) capital structure of 53.33% debt, 46.67% equity, as reflected in 2008 rates using the OEB 2008 IRM model. The current rate of return on equity is 9.00%, consistent with the capital structure and return specified in the OEB's Decision in RP-2005-0020/EB-2005-0395, dated 12th April, 2006. NOTL Hydro is requesting Board approval of a capital structure of 56.67% debt, 43.33% equity including an equity return of 8.57%.

NOTL Hydro is requesting this change in capital structure and associated return on equity primarily to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006. That Report requires all licensed Ontario electricity distributors to move toward a 60% debt/40% equity ratio. Details are provided in **Exhibit 6, Tab 1, Schedule 2**. NOTL Hydro believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Cost of Debt:

- **Long-Term Debt**

  Long-term debt cost information for the 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year periods are also filed at **Exhibit 6, Tab 1, Schedule 2**.

  Exhibit 6, Tab 1, Schedule 3 provides the details of NOTL Hydro's forecast long-term debt cost of 6.77% for 2009.

- **Short-Term Debt**

  NOTL Hydro is requesting a short term debt rate for the 2009 Test year of 4.47% in accordance with the letter from the OEB of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications, consistent with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors,* dated December 20, 2006.

  NOTL Hydro understands that the OEB will update short term debt rate in early 2009 for rates effective May 1, 2009.

Return on Equity:

NOTL Hydro is requesting a return on equity rate for the 2009 Test year of 8.57% in accordance with the letter from the OEB of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications, consistent with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors,* dated December 20, 2006.

NOTL Hydro understands that the OEB will update the return on equity rate in early 2009 for rates effective May 1, 2009.

CAPITAL STRUCTURE:

Capital Structure for 2006

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	10,654,127	50.00%	6.83%	727,476.99
Unfunded Short Term Debt				
Total Debt	10,654,127	50.00%		727,476.99
Common Share Equity	10,654,127	50.00%	9.00%	958,871.42
Total equity	10,654,127	50.00%		958,871.42
Total Rate Base	21,308,254	100%	7.91%	1,686,348.41

Capital Structure for 2007

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	10,717,225	50.00%	6.73%	721,423.87
Unfunded Short Term Debt				
Total Debt	10,717,225	50.00%		721,423.87
Common Share Equity	10,717,225	50.00%	9.00%	964,550.24
Total equity	10,717,225	50.00%		964,550.24
Total Rate Base	21,434,450	100%	7.87%	1,685,974.11

Capital Structure for 2008

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	11,532,676	53.33%	6.74%	777,292.07
Unfunded Short Term Debt				
Total Debt	11,532,676	53.33%		777,292.07
Common Share Equity	10,092,443	46.67%	9.00%	908,319.85
Total equity	10,092,443	46.67%		908,319.85
Total Rate Base	21,625,118	100%	7.79%	1,685,611.91

Capital Structure for 2009

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	11,450,782	52.67%	6.77%	775,462.73
Unfunded Short Term Debt	869,625	4.00%	4.47%	38,872.22
Total Debt	12,320,407	56.67%		814,334.95
Common Share Equity	9,420,209	43.33%	8.57%	807,311.89
Total equity	9,420,209	43.33%		807,311.89
Total Rate Base	21,740,616	100%	7.46%	1,621,646.84

COST OF LONG-TERM DEBT:

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)		Rate%	Year Applied to	Interest Cost
Pursuant to transfer by-law	Town of Niagara-on-the-Lake	Yes - shareholder	1-Nov-2000	$ 6,901,333	n/a	#	7.25%	2000	500,347
To finance construction of York TS	CIBC	No	1-Aug-2003	$ 2,630,760	15	#	6.03%	2003	158,635
To finance purchase of NOTL DS	CIBC	No	31-Oct-2005	$ 2,400,000	15	#	5.38%	2005	129,120
									0

Total Long Term Debt Outstanding at end of 2006	11,294,487	**Total Interest Cost for 2006**	771,202
		Weighted Debt Cost Rate for 2006	6.83%
Total Long Term Debt Outstanding at end of 2007	10,943,101	**Total Interest Cost for 2007**	736,629
		Weighted Debt Cost Rate for 2007	6.73%
Total Long Term Debt Outstanding at end of 2008	10,652,376	**Total Interest Cost for 2008**	717,961
		Weighted Debt Cost Rate for 2008	6.74%
Total Long Term Debt Outstanding at end of 2009	10,358,946	**Total Interest Cost for 2009**	701,522
		Weighted Debt Cost Rate for 2009	6.77%

Long-Term Debt Rate Calculations:

NOTL Hydro's calculations of its debt rate for the years 2006 to 2009 in the above table are as follows:

ACTUAL AND PROJECTED:			
Total Long Term Debt Outstanding at end of 2006	11,294,487	**Total Interest Cost for 2006**	771,202
Pursuant to transfer by-law	$6,666,333.12	Pursuant to transfer by-law	$498,926.81
To finance construction of York TS	$2,353,531.00	To finance construction of York TS	$145,548.97
To finance purchase of NOTL DS	$2,274,622.49	To finance purchase of NOTL DS	$126,725.76
		Weighted Debt Cost Rate for 2006	6.83%
Total Long Term Debt Outstanding at end of 2007	10,943,101	**Total Interest Cost for 2007**	736,629
Pursuant to transfer by-law	$6,566,333.12	Pursuant to transfer by-law	$483,309.12
To finance construction of York TS	$2,222,340.00	To finance construction of York TS	$136,661.44
To finance purchase of NOTL DS	$2,154,427.49	To finance purchase of NOTL DS	$116,658.01
		Weighted Debt Cost Rate for 2007	6.73%
Total Long Term Debt Outstanding at end of 2008	10,652,376	**Total Interest Cost for 2008**	717,961
Pursuant to transfer by-law	$6,566,333.12	Pursuant to transfer by-law	$476,059.20
To finance construction of York TS	$2,045,495.81	To finance construction of York TS	$128,589.13
To finance purchase of NOTL DS	$2,040,547.51	To finance purchase of NOTL DS	$113,312.36
		Weighted Debt Cost Rate for 2008	6.74%
Total Long Term Debt Outstanding at end of 2009	10,358,946	**Total Interest Cost for 2009**	**701,522**
Pursuant to transfer by-law	$6,566,333.12	Pursuant to transfer by-law	$476,059.15
To finance construction of York TS	$1,878,870.81	To finance construction of York TS	$118,777.99
To finance purchase of NOTL DS	$1,913,742.35	To finance purchase of NOTL DS	$106,684.96
		Weighted Debt Cost Rate for 2009	**6.77%**

RETURN ON EQUITY:

As indicated in the Overview above, NOTL Hydro is requesting an equity return for the 2009 Test year of 8.57% in accordance with the letter from the OEB of March 7, 2008 regarding cost of capital updates for 2008 cost of service applications.

NOTL Hydro understands that the OEB will update the return on equity rate in early 2009 for rates effective May 1, 2009.

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REVENUE DEFICIENCY - OVERVIEW:

NOTL Hydro has provided detailed calculations supporting its 2009 revenue deficiency. The net revenue deficiency is calculated as $138,143 and when grossed up for PILs NOTL Hydro's revenue deficiency is $206,184.

Table 1 on the following page provides the revenue deficiency calculations for the 2009 Test Year at Existing 2008 OEB-approved rates and the 2009 Test Year Service Revenue Requirement of $5,191,140.

Table 1

Calculation of Revenue Deficiency

	2009 Test Existing Rates	2009 Test Proposed Rates
Revenue		
Suff/ Def From Below.		$206,184
Distribution Revenue	$4,623,334	$4,623,334
Other Operating Revenue (Net)	$361,622	$361,622
Total Revenue	$4,984,956	$5,191,140
Distribution Costs		
Operation, Maintenance, and Administration	$1,864,661	$1,864,661
Depreciation & Amortization	$1,245,184	$1,245,184
PropertyTax	$33,450	$33,450
Capital Tax	$15,166	$15,166
Interest- Deemed Interest	$814,335	$814,335
Total Costs and Expenses	$3,972,797	$3,972,797
Utility Income Before Income Taxes	$1,012,159	$1,218,343
Net Adjustments per 2008 Pils	$27,206	$27,206
Taxable Income	$1,039,365	$1,245,550
Income Tax	$342,991	$411,031
Rate	*33.0%*	*33.0%*
Utility Income	$669,168	$807,312
Rate Base	$21,740,616	$21,740,616
Equity	43.33%	43.33%
Equity Component Rate Base	$9,420,209	$9,420,209
Income / Equity Rate Base %	7.10%	8.57%
Target Return -Equity on Rate Base	8.57%	8.57%
Return- Equity on Rate Base	$807,312	$807,312
Revenue Deficiency	$138,143	
Revenue Deficiency (Gross-up)	$206,184	

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COST ALLOCATION OVERVIEW:

Introduction:

On September 29, 2006, the OEB issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. NOTL Hydro prepared a cost allocation information filing consistent with NOTL Hydro's understanding of the Directions, the Guidelines, the Model and the Instructions. NOTL Hydro submitted this filing to the OEB on December 13, 2006.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications.

Background:

In the mid-1980's, Ontario Hydro completed the most recent cost allocation study on the distribution function, but this was an integrated cost allocation study. The integrated study reviewed not only the distribution function but the full costs of providing electricity to customers which included energy and transmission. Distribution represented only approximately 15% of the total costs reviewed. The results of this integrated study assisted Ontario Hydro in developing the Standard Application of Rates that were used by Municipal Electric Utilities to develop the bundled rates they charged customers until 2000.

Under the *Energy Competition Act, 1998*, the former Ontario Hydro was restructured into separate transmission/distribution (Hydro One) and generation (Ontario Power Generation) companies (among others). This was in part to facilitate the establishment of competitive markets for the electricity as a commodity. In furtherance of that objective, the rates charged by distributors were "unbundled" from transmission and commodity portions of the customer's bill. The unbundling also facilitated the addition of commercial returns on equity, debt rates and Payments in Lieu of Taxes ("PILs") to the distribution rates, in keeping with government policy. The unbundling of distribution from generation and transmission was completed in 2000/2001 using the OEB's 2000 Electricity Distribution Rate Handbook and the Rate Unbundling and Design Model (the "RUD" model). The Rate Handbook and RUD model provided a method to unbundle distribution rates from the other rates by rate classification but they did not determine whether the unbundled rates fully collected the cost of providing distribution service to each rate classification. The Directions issued by the OEB in 2006 along with the Guidelines, Model and Instructions represented the first time a cost allocation study has been conducted in Ontario that focuses completely on distribution costs and whether or not the distribution rates are collecting the cost of providing distribution service to the corresponding rate classifications.

SUMMARY OF RESULTS AND PROPOSED CHANGES:

Results of the Cost Allocation Study:

The data used in the Model was consistent with NOTL Hydro cost data that supported its 2006 OEB-approved distribution rates. Consistent with the Guidelines, NOTL Hydro assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to NOTL Hydro, its engineering records and its customer and financial information systems.

The results of a cost allocation study are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage shows the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

The following table outlines the revenue to cost ratios from the cost allocation informational filing submitted by NOTL Hydro on December 13, 2006. In addition, the dollar amount by which each rate classification is being subsidized or over-contributing is provided. The calculations are based on NOTL Hydro’s OEB-approved 2006 electricity distribution rates.

Table 1

Revenue to Cost Ratios as Filed in NOTL Hydro's 2006 Cost Allocation Informational Filing

Rate Classification	Revenue to Cost Ratio	$ Over Contributing ($ Under Contributing)
Residential	88.74%	($267,358)
GS < 50 kW	91.74%	($94,943)
GS > 50 kW	183.49%	$571,607
Street Lights	14.85%	($189,285)
Sentinel Lights	23.88%	($19,532)
Unmetered Scattered Load	97.26%	($489)
Total	100%	$0

Proposed Adjustment to Cost Allocation:

On November 28, 2007, the OEB issued its "Report on Application of Cost Allocation for Electricity Distributors" (the "Cost Allocation Report"). In the Cost Allocation Report, the OEB established what it considered to be the appropriate target ranges of revenue to cost ratios. Table 2 below summarizes the OEB's target ranges from the Cost Allocation Report as well as NOTL Hydro results from the cost allocation model. As can be seen from the table, the cost allocation results for NOTL Hydro indicate the Street Lights and Sentinel Lights classes fell well below the proposed revenue to cost ratio ranges, and the GS>50kW class fell a little above the proposed range.

Table 2
OEB (EB-2007-0667) Revenue to Cost Ratio Ranges
& NOTL Hydro Results in 2006 Cost Allocation Informational Filing

Customer Class	Low	High	NOTL Hydro
Residential	85%	115%	88.74%
GS <50 kW	80%	120%	91.74%
GS>50 kW	80%	180%	183.49%
Street Lights	70%	120%	14.85%
Sentinel Lights	70%	120%	23.88%
Unmetered Scattered Load	80%	120%	97.26%

With regard to the Sentinel Lights class, NOTL Hydro is proposing to eliminate this class as explained in **Exhibit 9, Tab 1, Schedule 6**. Consequently, the OEB proposed range is not applicable for 2009 rates.

For the Street Lights class, NOTL Hydro has noted the OEB's decisions on 2008 cost of service applications where the revenue to cost ratios for these classes fell below the minima of the ranges, and where the OEB directed that the ratios be moved part way towards the minimum of the range. As a result, NOTL Hydro is proposing to set rates that move the revenue to cost ratio 50% of the way from what the ratio was in the cost allocation filing per Table 2 above towards the minimum ("Low") of the OEB proposed range.

For the Residential and GS<50kW classes, NOTL Hydro is proposing to set rates that move the revenue to cost ratio from what the ratio was in the cost allocation filing per Table 2 above 50% of the way towards the 100% level.

With regard to the Unmetered Scattered Loads class, NOTL Hydro is proposing to set rates that move the revenue to cost ratio to 100%.

For the GS>50kW class, NOTL Hydro is proposing to set rates that result in 100% of the service revenue requirement being allocated across classes after the above adjustments to other classes are made, i.e. the ratio would be in effect a balancing proportion. This adjustment brings the revenue to cost ratio for this class within the OEB proposed range and corresponds to a movement of approximately 48% of the way from what the ratio was in the cost allocation filing per Table 2 towards the 100% level.

The approach described above is summarized in Table 3 below, where "CAR" ratio refers to the ratios in Table 2 above:

Table 3

Customer Class	Low	High	Approach
Residential	85%	115%	Move 1/2 way from "CAR" ratio to 100%
GS <50 kW	80%	120%	Move 1/2 way from "CAR" ratio to 100%
GS>50 kW	80%	180%	Balancing - move within range
Street Lighting	70%	120%	Move 1/2 way from "CAR" ratio to "Low"
Sentinel Lighting	70%	120%	N/A
Unmetered Scattered Load	80%	120%	Move to 100%

The resulting proposed revenue to cost ratios for all classes are summarized in Table 4 below:

Table 4

OEB (EB-2007-0667) Revenue to Cost Ratio Ranges
& NOTL Hydro Proposed Revenue to Cost Ratio

Customer Class	Low	High	NOTL Hydro
Residential	85%	115%	94.37%
GS <50 kW	80%	120%	95.87%
GS>50 kW	80%	180%	145.15%
Street Lighting	70%	120%	42.43%
Sentinel Lighting	70%	120%	N/A
Unmetered Scattered Load	80%	120%	100.00%

From the proposed ratios in Table 4, the allocation of the base revenue requirement is calculated as follows:

- The amount of the 2009 total service revenue requirement is allocated across rate classes using the revenue requirement proportions from the 2006 cost allocation study. Since the sentinel light class is to be eliminated in 2009, the proportion for this class is pro-rated across the other classes. The resulting amounts represent what would be a 100% revenue to cost ratio;

- Rather than 100%, the amounts calculated above are multiplied by the proposed revenue to cost ratios as shown in Table 4 above, to obtain the proposed service revenue from each class;

- The 2009 miscellaneous revenue is allocated across rate classes using the miscellaneous revenue proportions from the 2006 cost allocation study. Again, since the sentinel light class is to be eliminated in 2009, the proportion for this class is pro-rated across the other classes;

- The miscellaneous revenue for each class is subtracted from the proposed service revenue requirement for each class as calculated above in order to obtain the base revenue dollars and % by class.

The details of the above calculations are shown in Table 5 below.

Table 5
Calculation of Base Revenue % by Class

Class	Service Revenue Requirement - 2006 Cost Allocation Study	Service Revenue Requirement % - 2006 Cost Allocation Study	2009 Service Revenue Requirement at 100% Revenue/Cost Ratio*	2009 Proposed Revenue Cost Ratio	2009 Service Revenue Requirement at Proposed Revenue/Cost Ratio	Miscellaneous Revenue Allocation - 2006 Cost Allocation Study	Miscellaneous Revenue % - 2006 Cost Allocation Study	2009 Miscellaneous Revenue*	2009 Base Rev Requirement at Proposed Revenue/Cost Ratio	2009 Base Revenue Per Class %
Residential	2,375,367	53.09%	2,771,676	94.37%	2,615,694	111,335	60.11%	217,825	2,397,869	49.65%
GS <50 kW	1,148,759	25.67%	1,340,419	95.87%	1,285,028	49,445	26.70%	96,738	1,188,290	24.60%
GS>50 kW	684,646	15.30%	798,873	145.15%	1,159,588	19,511	10.53%	38,174	1,121,414	23.22%
Street Light	222,303	4.97%	259,393	42.43%	110,051	2,733	1.48%	5,348	104,703	2.17%
Sentinel	25,659	0.57%	N/A	N/A	N/A	377	0.20%	N/A	N/A	N/A
Unmetered Scattered Load	17,808	0.40%	20,779	100.00%	20,779	1,808	0.98%	3,538	17,241	0.36%
TOTAL	4,474,543	100.00%	5,191,140		5,191,140	185,211	100.00%	361,622	4,829,518	100.00%

The proposed class shares of the base revenue requirement are summarized in Table 6 below in comparison with the shares in the cost allocation study and the shares at existing rates.

Table 6

Summary of Class Shares of Base Distribution Revenue

Customer Class	Cost Allocation Study	At Existing Rates	At Proposed Rates	Cost Allocation Study	At Existing Rates	At Proposed Rates
Residential	52.88%	47.25%	49.65%	2,553,851	2,281,944	2,397,869
GS <50 kW	25.75%	21.31%	24.60%	1,243,681	1,029,385	1,188,290
GS>50 kW	15.75%	30.20%	23.22%	760,699	1,458,734	1,121,414
Street Light	5.26%	0.82%	2.17%	254,045	39,778	104,703
Sentinel	N/A	0.00%	N/A	N/A	0	N/A
Unmetered Scattered Load	0.36%	0.41%	0.36%	17,241	19,677	17,241
TOTAL BASE REVENUE	**100.00%**	**100.00%**	**100.00%**	**4,829,518**	**4,829,518**	**4,829,518**

Numbers may appear not to multiply due to rounding of printed %'s.

The above Table shows that the proposed class shares move nearer to the cost allocation study shares than what they would be at existing rates.

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RATE DESIGN OVERVIEW:

This exhibit documents the calculation of NOTL Hydro's proposed distribution rates by rate class for the 2009 test year, based on rate design as proposed in this Exhibit.

NOTL Hydro has determined its total 2009 service revenue requirement to be $5,191,140. The total revenue offsets in the amount of -$361,622 reduce NOTL Hydro's total service revenue requirement to a base revenue requirement to $4,829,518, which is used to determine the proposed distribution rates. The base revenue requirement is derived from NOTL Hydro's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and NOTL Hydro's regulated return on rate base. The revenue requirement is summarized in the table below:

Service Revenue Requirement

OM&A Expenses	1,898,111
Amortization Expenses	1,245,184
Total Distribution Expenses	**3,143,296**
Regulated Return On Capital	1,621,647
PILs	426,198
Service Revenue Requirement	**5,191,140**

Base Revenue Requirement

Service Revenue Requirement	5,191,140	
Less: Revenue Offsets	-361,622	
Base Revenue Requirement		**4,829,518**
Allocated to:		
Low Voltage Wheeling Costs	0	
Directly Assigned CDM	0	
Other	4,829,518	
Total		**4,829,518**

The base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as shown in **Exhibit 8 Tab 1, Schedule 2 – Table 4**.

Proposed Apportionment of Revenue to Rate Classes

Customer Class	Proposed Proportion of Revenue
Residential	49.65%
GS <50 kW	24.60%
GS>50 kW	23.22%
Street Light	2.17%
Sentinel	N/A
Unmetered Scattered Load	0.36%
Total	100.00%

The following table outlines the results of this allocation.

Allocation of Outstanding Base Revenue Requirement

Customer Class	Proposed Revenue
Residential	$2,397,869
GS <50 kW	$1,188,290
GS>50 kW	$1,121,414
Street Light	$104,703
Sentinel	N/A
Unmetered Scattered Load	$17,241
Total	$4,829,518

Determination of Monthly Fixed Charges:

NOTL Hydro's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are summarized in the table below.

Current Monthly Fixed Charges

Customer Class	**Current Monthly Fixed Charge**
Residential	$17.47*
GS <50 kW	$39.87*
GS>50 kW	$463.48*
Street Lighting	$1.10
Sentinel Lighting	$2.92
Unmetered Scattered Load	$39.87

(excluding $0.24 smart meter rate rider)*

Using the existing approved fixed charges applied to the forecasted number of customers for 2009, the following table outlines the current split between fixed and variable distribution revenue.

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt
Residential	37.15%	62.85%
GS <50 kW	41.61%	58.39%
GS>50 kW	51.21%	48.79%
Street Light	32.66%	67.34%
Sentinel	N/A*	N/A*
Unmetered Scattered Load	19.15%	80.85%
	(Sentinel class eliminated in 2009)*	

With regard to the appropriate fixed/variable split, NOTL Hydro notes that in Findings on certain 2008 rate rebasing applications, where the Applicant has proposed distribution rates that maintain the existing fixed/variable split for the main customer classes, the OEB has stated that:

> *"The Board has convened a consultation with the industry and stakeholders respecting many aspects of rate design, including the fixed/variable split. (EB-2007-0031). The relationship between the fixed and variable portions of the customer bill has important implications for ratemaking, and the magnitude of the fixed charge has benefits and drawbacks for various stakeholders.*
>
> *In light of the consultation initiated by the Board on these subjects it would be inappropriate to attempt to predict its outcome and to impose a new structure on the Applicant. Accordingly the Board accepts the Applicant's proposal."*

Therefore, NOTL Hydro submits that it is appropriate for 2009 to maintain the same fixed/variable proportions assumed in the current rates.

On this basis, the proposed fixed distribution charges are as follows:

Proposed Fixed Distribution Charge

Customer Class	Total Base Revenue Requirement	Fixed Revenue Proportion	2009 Test Year Annualized Customers /Connections	Proposed Fixed Distribution Charge
Residential	$2,397,869	62.85%	79,008	$19.08
General Service Less Than 50 kW	$1,188,290	58.39%	14,508	$47.83
General Service Greater Than 50 kW	$1,121,414	48.79%	1,478	$370.25
Street Lights	$104,703	67.34%	23,436	$3.01
Sentinel Lights	N/A	N/A*	0	N/A
Unmetered Scattered Load	$17,241	80.85%	384	$36.30
Total	$4,829,518		48,186	

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides NOTL Hydro's calculations of its proposed variable distribution charges for the 2009 Test Year assuming the fixed/variable split tabulated above:

Variable Distribution Charge Calculation

Customer Class	Total Base Revenue Requirement	Variable Revenue Proportion	2009 Test Year usage	Unit of Measure	Variable Revenue Charge
Residential	$2,397,869	37.15%	66,320,829	kWh	$0.0134
General Service Less Than 50 kW	$1,188,290	41.61%	34,349,093	kWh	$0.0144
General Service Greater Than 50 kW	$1,121,414	51.21%	207,437	kW	$2.7683*
Street Lights	$104,703	32.66%	2,900	kW	$11.7906
Sentinel Lights	N/A	N/A*	0	kW	N/A
Unmetered Scattered Load	$17,241	19.15%	302,169	kWh	$0.0109
Total	$4,829,518				

**prior to adjustment (rounded) of $0.1172 per kW*
for class usage of 207,437 kW
to offset total allowance for eligible customers of $24,326

Proposed Adjustment to Transformer Allowance:

Currently, NOTL Hydro provides a transformer ownership allowance of ($0.60) per kW to those GS>50kW customers that own their transformation facilities. NOTL Hydro proposes to reduce the transformer ownership allowance to ($0.56) per kW. The proposed allowance is the allowance that was filed with the 2006 Cost Allocation Information Filing on December 13, 2006 [EB-2005-0395 / EB-2006-0247].

The following Table details the calculation of the resulting total transformer allowance for eligible customers at the current and proposed rates:

Total Transformer Allowance Calculation

Description	2006 Actual		2007 Actual		2008 Forecast		2009 Test	
	kW	$	kW	$	kW	$	kW	$
General Service:								
GS>50 kW	68,600	**($41,160.24)**	55,488	**($33,292.73)**	49,464	**($29,678.33)**	43,440	**($24,326.33)**
Transformer Allowance rate	$0.60		$0.60		$0.60		$0.5600	

Proposed Distribution Rates:

The following table sets out NOTL Hydro’s proposed 2009 electricity distribution rates based on the foregoing calculations (excluding rate riders for smart meters and disposal of deferral and variance account balances):

2009 TEST YEAR - Distribution Rates ($)

Customer Class	Per Connection	Per Customer	Per kW	Per kWh
Residential	0.0000	19.08	0.0000	0.0134
GS <50 kW	0.0000	47.83	0.0000	0.0144
GS>50 kW	0.0000	370.25	2.8856	0.0000
Street Light	3.0087	0.00	11.7906	0.0000
Unmetered Scattered Load	36.30	0.00	0.0000	0.0109

Transformer Ownership Allowance			(0.5600)	

Proposed Smart Meter Rate Rider:

On June 25, 2008 the government filed amendments to three smart metering regulations, namely O. Reg. 427/06 (Smart Meters: Discretionary Metering and Procurement Principles), O. Reg. 426/06 (Smart Meters: Cost Recovery), and O. Reg. 393/07 (Designation of Smart Metering Entity).

Amendments to O. Reg. 427/06 (Smart Meters: Discretionary Metering Activity and Procurement Principles) will:

- Authorize metering activities pursuant to the Request for Proposal (RFP) for Advanced Metering Infrastructure (AMI) – Phase 1 Smart Meter Deployment issued August 14, 2007 by London Hydro Inc. This would include distributors named in the RFP and those distributors that procure AMI pursuant to the parameters established by the RFP;

NOTL Hydro along with our 8 LDC partners in the Niagara-Erie Power Alliance (NEPA) have agreed to jointly purchase, install and operate AMI infrastructure including the local communication network and system software in accordance with the London Hydro RFP parameters. Each LDC will purchase their own meters and utility-specific hardware but jointly operate the AMI system with NEPA members as a virtual utility. NEPA members include Brant County Power, Brantford Power, Norfolk Power, Haldimand County Hydro, Grimsby Power, Niagara Peninsula Energy, Fortis and Welland Hydro.

At the time of this submission, negotiations are underway with a Fairness Commissioner-designated vendor. It is anticipated that NOTL Hydro will be scheduled for full implementation of Smart Meters in mid to late 2009 in a process expected to take less than two months and require a capital outlay estimated at $1.6-1.7 million. NOTL Hydro has noted OEB decisions for those 2008 cost of service rate Applicants that are in a similar situation to NOTL Hydro (for example, Lakefront Utilities Inc. and PUC Distribution Inc.). In keeping with these decisions, NOTL Hydro seeks a rate rider of **$1.00 per customer per month** to fund Smart Meter activities.

This rate rider would be applicable to the residential, GS <50kW and GS >50kW classes. The rate riders are shown in **Exhibit 9, Tab 1, Schedule 7**

RATE MITIGATION:

NOTL Hydro submits that the bill impacts of its proposed 2009 electricity distribution rates are not so significant as to warrant any mitigation measures.

RETAIL TRANSMISSION RATES:

NOTL Hydro's application to reduce its retail transmission rates effective May 1, 2008 was approved by the OEB on April 18 2008 [EB-2007-0813]. No further adjustments are proposed for 2009. However, at the time of this application, NOTL Hydro is still awaiting an OEB decision as to the validity of a unilateral Hydro One load assignment to NOTL Hydro that has a financial impact of at least $123,000 annually in Network Transformation Connection Service charges plus potential Low Voltage Shared Line charges. NOTL Hydro continues to dispute this load assignment but in the interim is accruing these potential monthly charges. The current Retail Transmission Rates reflect the accrual process.

EXISTING RATE CLASSES:

Residential

This classification applies to an account taking electricity at 750 volts or less 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.

General Service Less Than 50 kW

This classification applies to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW

This classification applies to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 50 kW but less than 5,000 kW.

Unmetered Scattered Load

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

Street Lighting

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established by an approved OEB process.

Sentinel Lighting

This classification refers to an account for unmetered private driveway and roadway lighting controlled by photo-cells. A 12 hour average operation is assumed.

EXISTING RATE SCHEDULE:

The following Schedule is NOTL Hydro's approved Tariff of Rates and Charges effective May 1, 2008. The service charges for the Residential, GS<50kW and GS>50kW classes include the approved smart meter rate rider of $0.24.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.71
Distribution Volumetric Rate	$/kWh	0.0123
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0018
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	40.11
Distribution Volumetric Rate	$/kWh	0.0120
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	463.72
Distribution Volumetric Rate	$/kW	3.4654
Retail Transmission Rate – Network Service Rate	$/kW	1.8202
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6553
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	1.9673
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.5761
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	39.87
Distribution Volumetric Rate	$/kWh	0.0120
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.92
Distribution Volumetric Rate	$/kW	5.8909
Retail Transmission Rate – Network Service Rate	$/kW	1.3797
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5172
Wholesale Market Service Rate	$/kWh	0.0052

Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.10
Distribution Volumetric Rate	$/kW	4.3107
Retail Transmission Rate – Network Service Rate	$/kW	1.3727
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5066
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for Previous Billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Account History	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque Charge (plus bank charges)	$	15.00
Charge to Certify Cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – No Disconnection	$	30.00
Disconnect/Reconnect Charges at Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charges at Meter – After Regular Hours	$	185.00
Disconnect/Reconnect Charges at Pole– During Regular Hours	$	185.00
Disconnect/Reconnect Charges at Pole – After Regular Hours	$	415.00
Service Call – Customer-owned Equipment – During Regular Hours	$	30.00
Service Call – Customer-owned Equipment – After Regular Hours	$	165.00
Install/Remove Load Control Device – During Regular Hours	$	65.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Temporary Service Install & Remove – Overhead – No Transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service Install & Remove – Overhead – with Transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Specific Charge for Bell Canada Access to the Power Poles – per pole/year	$	18.36

Note: Specific Charge for Bell Canada Access to the Power Poles is valid only until the existing joint-use agreement is terminated.

Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0501
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0161
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0396
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0060

PROPOSED RATE CLASSES:

Residential

This classification applies to an account taking electricity at 750 volts or less 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.

General Service Less Than 50 kW

This classification applies to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW

This classification applies to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 50 kW but less than 5,000 kW.

Unmetered Scattered Load

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

[Sentinel Lighting:

NOTL Hydro proposes to eliminate this customer class. The latest version of the Affiliate Relations Code confirms the OEB's direction that LDC's must not participate in the sentinel light rental business either directly or through an affilate. A few accounts are expected to be shifted to the USL rate class where feasible to the customer and providing that the lights are not on NOTL Hydro poles. The Town of NOTL may assume some of the sentinel lights and add to their Street Light account.]

Street Lighting:

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established by an approved OEB process.

SCHEDULE OF PROPOSED RATES AND CHARGES:

RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges
Effective May 1, 2009

Customer Class	Item Description	Unit	Rate ($)
RESIDENTIAL			
	Monthly Service Charge	per month	19.08
	Distribution Volumetric Rate	per kWh	0.0134
	LRAM and SSM Rate Rider	per kWh	0.0001
	Smart Meter Rate Rider	per month	1.00
	DVA Recovery Rate Rider	per kWh	0.0003
GENERAL SERVICE < 50 kW			
	Monthly Service Charge	per month	47.83
	Distribution Volumetric Rate	per kWh	0.0144
	LRAM and SSM Rate Rider	per kWh	0.0001
	Smart Meter Rate Rider	per month	1.00
	DVA Recovery Rate Rider	per kWh	0.0003
GENERAL SERVICE > 50 kW			
	Monthly Service Charge	per month	370.25
	Distribution Volumetric Rate	per kW	2.8856
	Smart Meter Rate Rider	per month	1.00
	DVA Recovery Rate Rider	per kW	0.0629
STREET LIGHTING			
	Monthly Service Charge	per month	3.01
	Distribution Volumetric Rate	per kW	11.7906
	DVA Recovery Rate Rider	per kW	0.1291
UNMETERED SCATTERED LOAD			
	Monthly Service Charge	per month	36.30
	Distribution Volumetric Rate	per kWh	0.0109
	DVA Recovery Rate Rider	per kWh	0.0045

RATES SCHEDULE (Part 2)

Schedule of Distribution Rates and Charges
Effective May 1, 2009

Specific Service Charges		
Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for Previous Billing	$	15.00
Request for Other Billing Information	$	15.00
Easement Letter	$	15.00
Account History	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque Charge (plus bank charges)	$	15.00
Charge to Certify Cheque	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special Meter Reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of Account Charge – No Disconnection	$	30.00
Disconnect/Reconnect Charges at Meter – During Regular Hours	$	65.00
Disconnect/Reconnect Charges at Meter – After Regular Hours	$	185.00
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Disconnect/Reconnect Charges at Pole – After Regular Hours	$	415.00
Service Call – Customer-owned Equipment – During Regular Hours	$	30.00
Service Call – Customer-owned Equipment – After Regular Hours	$	165.00
Install/Remove Load Control Device – During Regular Hours	$	65.00
Install/Remove Load Control Device – After Regular Hours	$	185.00
Temporary Service Install & Remove – Overhead – No Transformer	$	500.00
Temporary Service Install & Remove – Underground – No Transformer	$	300.00
Temporary Service Install & Remove – Overhead – with Transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Specific Charge for Bell Canada Access to the Power Poles – per pole/year	$	18.36
Note: Specific Charge for Bell Canada Access to the Power Poles is valid only until the existing joint-use agreement is terminated.		

Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.56
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00

Loss Factors	
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0501
Total Loss Factor - Secondary Metered Customer > 5,000 kW	1.0156
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0396
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0055

RECONCILIATION OF RATE CLASS REVENUE:

The table below 1 recaps the fixed charge data required for the reconciliation calculation:

Customer Class	Number of Customers/ Connections	Proposed Fixed Rate $ per month
Residential	6,584	$19.08
GS <50 kW	1,209	$47.83
GS>50 kW	123	$370.25
Street Light	1,953	$3.0087
Unmetered Scattered Load	32	$36.30

The table below recaps the variable charge data required for the reconciliation calculation:

Customer Class	Volumes kW or kWh		Proposed Variable Rate $ per kW or kWh
Residential	66,320,829	kWh	$0.0134
GS <50 kW	34,349,093	kWh	$0.0144
GS>50 kW	207,437	kW	$2.8856
Street Light	2,900	kW	$11.7906
Unmetered Scattered Load	302,169	kWh	$0.0109

Calculating with the above data, the table below provides the reconciliation:

2009 Test Year Distribution Revenue Reconciliation

Customer Class	Fixed Distribution Revenue at Proposed Rates	Variable Distribution Revenue at Proposed Rates	Total Fixed and Variable Distribution Revenue	Transformer Allowance Credit	Total Distribution Revenue	Expected (Base Revenue Requirement)
Residential	$ 1,507,473	$ 888,699	$ 2,396,172		$ 2,396,172	$ 2,397,869
GS <50 kW	$ 693,918	$ 494,627	$ 1,188,545		$ 1,188,545	$ 1,188,290
GS>50 kW	$ 547,172	$ 598,581	$ 1,145,753	($24,326.33)	$ 1,121,427	$ 1,121,414
Street Light	$ 70,512	$ 34,191	$ 104,703		$ 104,703	$ 104,703
Unmetered Scattered Load	$ 13,940	$ 3,294	$ 17,233		$ 17,233	$ 17,241
Total	**$ 2,833,014**	**$ 2,019,392**	**$ 4,852,406**	**($24,326.33)**	**$ 4,828,080**	**$ 4,829,518**

Difference Due to Rate Rounding

$ 1,438 Shortfall

BILL IMPACTS:

The Tables below present the results of the assessment of customer total bill impacts for representative levels of consumption by customer per rate class. Impacts are derived using the applicable May 1, 2008 rates and the proposed 2009 distribution rates, including Rate Riders for the recovery of Deferral and Variance Accounts, Smart Meters and LRAM/SSM.

BILL IMPACTS *(Monthly Consumptions)*

RESIDENTIAL

Consumption: 1,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			17.47			19.08	1.61	9.22%	1.41%
Distribution (kWh)	1,000	0.0123	12.30	1,000	0.0134	13.40	1.10	8.94%	0.96%
Smart Meter Rider (per month)			0.24			1.00	0.76	316.67%	0.66%
LRAM & SSM Rider (kWh)	1,000	0.0000		1,000	0.0001	0.10	0.10		0.09%
DVA Recovery Rider (kWh)	1,000	0.0000	0.00	1,000	0.0003	0.30	0.30		0.26%
Sub-Total			**30.01**			**33.88**	**3.87**	**12.90%**	**3.38%**
Other Charges (kWh)	1,050	0.0199	20.90	1,050	0.0199	20.90	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	600	0.0530	31.80	600	0.0530	31.80	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	450	0.0620	27.91	450	0.0620	27.91	0.00	0.00%	0.00%
Total Bill			**110.61**			**114.48**	**3.87**	**3.50%**	**3.38%**

GENERAL SERVICE < 50 kW

Consumption: 2,000 kWh

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			39.87			47.83	7.96	19.96%	3.28%
Distribution (kWh)	2,000	0.0120	24.00	2,000	0.0144	28.80	4.80	20.00%	1.98%
Smart Meter Rider (per month)			0.24			1.00	0.76	316.67%	0.31%
LRAM & SSM Rider (kWh)	2,000	0.0000		2,000	0.0001	0.20	0.20		0.08%
DVA Recovery Rider (kWh)	2,000	0.0000	0.00	2,000	0.0003	0.60	0.60		0.25%
Sub-Total			**64.11**			**78.43**	**14.32**	**22.34%**	**5.90%**
Other Charges (kWh)	2,100	0.0194	40.74	2,100	0.0194	40.74	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	750	0.0530	39.75	750	0.0530	39.75	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	1,350	0.0620	83.71	1,350	0.0620	83.71	0.00	0.00%	0.00%
Total Bill			**228.32**			**242.64**	**14.32**	**6.27%**	**5.90%**

GENERAL SERVICE > 50 kW

Consumption: 500,000 kWh, 1,100 kW

	2008 BILL			2009 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			463.48			370.25	(93.23)	(20.12%)	(0.20%)
Distribution (kWh)	500,000	0.0000	0.00	500,000	0.0000	0.00	0.00		0.00%
Distribution (kW)	1,100	3.4654	3,811.94	1,100	2.8856	3,174.16	(637.78)	(16.73%)	(1.39%)
Smart Meter Rider (per month)			0.24			1.00	0.76	316.67%	0.00%
DVA Recovery Rider (kW)	1,100	0.0000	0.00	1,100	0.0629	69.19	69.19		0.15%
Sub-Total			**4,275.66**			**3,614.60**	**(661.06)**	**(15.46%)**	**(1.44%)**
Other Charges (kWh)	525,050	0.0132	6,930.66	525,050	0.0132	6,930.66	0.00	0.00%	0.00%
Other Charges (kW)	1,100	2.4755	2,723.05	1,100	2.4755	2,723.05	0.00	0.00%	0.00%
Cost of Power Commodity (kWh)	0	0.0530	0.00	0	0.0530	0.00	0.00		0.00%
Cost of Power Commodity (kWh)	525,050	0.0620	32,553.10	525,050	0.0620	32,553.10	0.00	0.00%	0.00%
Total Bill			**46,482.47**			**45,821.41**	**(661.06)**	**(1.42%)**	**(1.44%)**

Street Lighting

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	435	1.1000	478.50	435	3.0087	1,308.78	830.28	173.52%	19.27%
435 Connections	Distribution (kWh)	27,600	0.0000	0.00	27,600	0.0000	0.00	0.00		0.00%
27,600 kWh	Distribution (kW)	60	4.3107	258.64	60	11.7906	707.44	448.79	173.52%	10.41%
60 kW	DVA Recovery Rider (kW)	60	0.0000	0.00	60	0.1291	7.75	7.75		0.18%
	Sub-Total			**737.14**			**2,023.97**	**1,286.82**	**174.57%**	**29.86%**
	Other Charges (kWh)	28,983	0.0132	382.57	28,983	0.0132	382.57	0.00	0.00%	0.00%
	Other Charges (kW)	60	1.8793	112.76	60	1.8793	112.76	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	750	0.0530	39.75	750	0.0530	39.75	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	28,233	0.0620	1,750.43	28,233	0.0620	1,750.43	0.00	0.00%	0.00%
	Total Bill			**3,022.65**			**4,309.48**	**1,286.82**	**42.57%**	**29.86%**

Unmetered Scattered Load

		2008 BILL			2009 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			39.87			47.83	7.96	19.96%	6.54%
800 kWh	Distribution (kWh)	800	0.0120	9.60	800	0.0109	8.72	(0.88)	(9.17%)	(0.72%)
	DVA Recovery Rider (kWh)	800	0.0000	0.00	800	0.0045	3.60	3.60		2.96%
	Sub-Total			**49.47**			**60.15**	**10.68**	**21.59%**	**8.77%**
	Other Charges (kWh)	840	0.0194	16.30	840	0.0194	16.30	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	750	0.0530	39.75	750	0.0530	39.75	0.00	0.00%	0.00%
	Cost of Power Commodity (kWh)	90	0.0620	5.58	90	0.0620	5.58	0.00	0.00%	0.00%
	Total Bill			**111.10**			**121.78**	**10.68**	**9.61%**	**8.77%**

INDEX FOR EXHIBIT 10

RECOVERY OF LRAM AND SSM AMOUNTS:

Overview:

On May 31, 2004, the Minister of Energy granted approval to all electricity distributors in Ontario to apply to the OEB for adjustments to their 2005 electricity distribution rates that would enable them to recover the third tranche of their incremental market adjusted revenue requirements (“MARR”). The Minister’s approval was conditional on a commitment to reinvest an equivalent amount in Conservation and Demand Management (“CDM”) initiatives. The CDM Plans of NOTL Hydro were approved by the OEB in December 2004 (with a Final Order issued in February 2005) and February 2005, respectively.

NOTL Hydro’ CDM efforts have been successful, but as a result, with decreases in kWh consumption and kW demand, NOTL Hydro has experienced distribution revenue losses. The OEB has authorized distributors to apply for Lost Revenue Adjustment Mechanism (“LRAM”) and Shared Savings Mechanism (“SSM”) adjustments. The authorization to apply for LRAM and SSM adjustments for 2005 and 2006 is derived from the OEB’s December 2004 decision on the Pollution Probe motion in file No. RP-2004-0203; and the OEB’s May 2005 Report on the 2006 Electricity Distribution Rate Handbook (the “Report”, OEB File No. RP-2004-0188). NOTL Hydro is also requesting LRAM adjustments for 2007.

At page 107 of the Report, the OEB addressed LRAM recoveries, stating:

> “In its December 2004 Decision RP-2004-0203, the board concluded that an LRAM was appropriate and that it should apply to 3rd tranche expenditures. The Board indicated, at that time, that the LRAM formula would be established as part of the 2006 proceeding.
>
> The Board continues to believe that an LRAM is appropriate and concludes that it will be retrospective, not prospective. At this time, greater accuracy will be achieved if the LRAM is calculated after-the-fact, based on actual results.
>
> Accordingly, a distributor will be expected to calculate the energy savings by customer class and to value those energy savings by the board-approved distribution charge

appropriate to that class. The resulting amount may be claimed in a subsequent rate year as compensation for lost revenue".

With respect to SSM, at page 110 of its Report, the OEB wrote:

> "The Board, in its RP-2004-0203 Decision, found that a distributor shareholder incentive was an appropriate way to encourage distributors to pursue CDM programs. The Board continues to be of this view. Distributors should be rewarded with 5 percent of the net savings established by the TRC test. The Board recognizes that it will be essential to establish certain inputs and to define avoided costs. Accordingly, the Board's Conservation Manual will address these matters. This will allow parties to screen CDM programs and calculate the relevant incentives."

At page 111 of the Report, the OEB wrote:

> "The SSM will apply to TRC benefits achieved by 3rd tranche expenditures as well as any incremental expenditures that are approved in 2006. However, as in the case of the Board's Decision with respect to 2005, the incentive will not apply to utility-side activities. Because the SSM will be retrospective, no claims for a shareholder incentive should be made in the 2006 rate applications.
>
> There has been considerable discussion in this proceeding as to whether CDM expenditures on the utility side should be differentiated from customer-side expenditures. The Board recognizes that conservation programs should have a balance between the two. It is important to recall however, the Board's earlier finding that the SSM incentive does not apply to utility-side investments. The Board previously ruled with respect to the 2005 SSM that the inclusion of capitalised assets into rate base provides sufficient incentives. The Board continues to hold that view."

In accordance with the Report, NOTL Hydro's LRAM/SSM request includes only customer-side activities. NOTL Hydro has calculated energy savings by customer class and valued those savings by the OEB-approved distribution charge appropriate to each class, as required by the Report.

In its April 28, 2005 "Guidelines for Electricity Distributors Wishing to Apply for SSM Incentive for 2005 Implementation of CDM Plans" (referred to here as the "SSM Guidelines"), the OEB stated (at page 2):

> "Inputs and assumptions of the TRC Test have to be clearly stated in the pre-filed evidence. Applicants may use the standard inputs for TRC calculation which are contained in the Board's Conservation Manual (available late June 2005). Where an applicant wishes to use other inputs, the applicant must provide supporting evidence, an

> explanation of its choice and, for comparison, the TRC Test results using the inputs contained in the Conservation Manual."

On September 8, 2005 the OEB issued its Conservation Manual, under the name of the Total Resource Cost Guide (the "TRC Guide"). The TRC Guide set out an OEB-approved methodology and associated parameters for the financial evaluation of CDM programs. The TRC Guide was revised October 2, 2006 to reflect the OEB's Decision in the EB-2005-0523 proceeding concerning the attribution of benefits between utilities and non-rate-regulated third parties.

In addition to the requirements with respect to this Application, the Filing Requirements contain provisions relating to applications for LRAM and SSM adjustments, and NOTL Hydro submits that it has relied on and complied with the LRAM/SSM provisions of the Report, the OEB's TRC Guide and the Filing Requirements in preparing this request for LRAM/SSM adjustments for the years 2005 and 2006 and also 2007 (LRAM only).

This request is also consistent with the OEB's Guidelines for Electricity Distributor Conservation and Demand Management, EB-2008-0037, dated March 28, 2008.

SUMMARY OF LRAM/SSM REQUEST:

NOTL Hydro seeks approval for the recovery of 2005, 2006 and 2007 LRAM and 2005 and 2006 SSM amounts as part of this Application. Recovery is to be based on a volumetric rate rider commencing May 1, 2009. NOTL Hydro is proposing a 2 year recovery period in order to mitigate customer rate impacts, therefore the rate rider would remain in effect until 30 April, 2011 .

The LRAM calculations are based on the kWh load reduction for each of the years 2005, 2006 and 2007 times the applicable variable distribution rate for that rate class. The LRAM calculation, in the amount of $12,168 , is net of "free ridership" in accordance with the OEB's TRC Guide and model and the OEB decision regarding the Toronto Hydro application.

The SSM calculation, in the amount of $8,563 , has been prepared in accordance with the SSM Guidelines and the TRC Guide which provide for 5 percent of the net savings established by the TRC test. As with the LRAM calculation, the SSM calculation is net of "free-ridership" in accordance with the TRC Guide and the Toronto Hydro Decision.

NOTL Hydro notes that it implemented four programs which were included in its CDM plans and approved by the OEB. These programs were previously summarized in NOTL Hydro's 2005, 2006 and 2007 Annual CDM Reports. Additionally, NOTL Hydro participated in two OPA programs in 2006 that have been included in the LRAM calculations.

The total combined LRAM and SSM amount for recovery is $20,731 . The LRAM and SSM amounts and corresponding rate riders are set out by rate class in Table 1 (LRAM and SSM Total Amounts and Rate Riders by Class), below. NOTL Hydro proposes a single rate rider for recovery of the total LRAM and SSM.

Table 1
LRAM and SSM Total Amounts and Rate Riders by Class

2009 Test Year - LRAM and SSM Rider

	Amounts (2005 to 2007)		Billing Units (2007)		Rate Riders			Two Year Rate Rider	Three Year Rate Rider	Number of Years to Use	Rate Rider to Use
	LRAM	SSM			LRAM	SSM	Total	Total	Total	(1, 2 or 3)	Total
Rate Class	$	$		Metrics	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	$/unit (kWh or kW)	2	$/unit (kWh or kW)
Residential	11,514	2,794	65,499,951	kWh	0.000176	0.000043	0.000218	0.000109	0.000073		0.0001
GS<50kW	654	5,769	34,969,161	kWh	0.000019	0.000165	0.000184	0.000092	0.000061		0.0001
Total	$12,168	$8,563									

NOTL Hydro considered recovery periods of 1, 2 or 3 years. Because rate riders are normally rounded to 4 decimal places in rate orders, the minimum per kWh rate that could be implemented is $0.0001. Over a 3 year period, this rate would over-recover the target recovery amount significantly for both classes. For 1 or 2 year recovery, the rates would be $0.0002 or $0.0001 respectively. At these rates, in each case, there would be a small under-recovery of $637 .

To minimize monthly bill impacts over the period when the riders are in effect, a 2 year recovery period is proposed, as shown in Table 1 above.

LOST REVENUE ADJUSTMENT MECHANISM:

The purpose of an LRAM adjustment is to account for the variance between forecasted volumes used to set class rates and actual volumes resulting from CDM programs. The LRAM recovery has been calculated as the approved savings per measure multiplied by the number of measures implemented for the particular programs targeted at each rate class.

In accordance with the Toronto Hydro Decision, NOTL Hydro has reduced the calculated load reduction for free ridership. Table 1 below summarizes the CDM load impacts by program and customer class.

Table 1
CDM Load Impacts by Program and Class

Program	Rate Group	Units Delivered	kWh	TRC $		kW	kW/Year	kWh/yr	kWh/life	Free Ridership	Life (Years)	Mechanism
2005												
LED Lighting	GS<50	380	19,018	$ 73,700.00	**	47.50	570	19,018	570,528	5%	30	LRAM / SSM
Mass Media Coupons	Residential	8,486	178,268	$ 23,241.00	**	46.12	553.4	178,268	900,386	10%	4-30	LRAM / SSM
*Energy Audits	Residential	1		-$ 88.89	**						n/a	SSM
2005 Sub-Total			**197,286**	**$ 96,852.11**		**93.62**	**1,123**	**197,286**	**1,470,914**			

* Educational Based

Program	Rate Group	Units Delivered	kWh	TRC $		kW	kW/Year	kWh/yr	kWh/life	Free Ridership	Life	Mechanism
2006												
Refrigerator Retirement (OPA)	Residential	482	131,868	$ 44,684.00		33.00	396	131,868	998,028	10%	6-20	LRAM
LED Christmas Light Trade-in	Residential	700	12,540	$ 12,546.00	**	5.00	60	12,540	376,200	5%	30	LRAM / SSM
Mass Media Coupons(OPA)	Residential	558	68,688	$ 24,976.00		2.26	27	68,688	595,796	10%	4-30	LRAM
2006 Sub-Total			**213,096**	**$ 82,206.00**		**40.26**	**483**	**213,096**	**1,970,024**			
				$ 179,058.11								

		Year	kWh	kW	kW/Year	kWh/yr	kWh/life
Cumulative Totals (2005-2007) for LRAM	2005 programs	2005	197,286	93.62	1,123	197,286	1,470,914
		2006	197,286	93.62	1,123	197,286	1,470,914
		2007	197,286	93.62	1,123	197,286	1,470,914
	2006 programs	2006	213,096	40.26	483	213,096	1,970,024
		2007	213,096	40.26	483	213,096	1,970,024
			1,018,050	**361.38**	**4,336**	**1,018,050**	**8,352,790**

	TRC $	
Non-Rate Base Total (For Eligible SSM marked with **)	**$ 109,398.11**	**

The reduction in distribution revenue is calculated on the foregone volumes resulting from CDM activities by class and at the variable distribution rates applicable to the years 2005, 2006 and 2007.

NOTL Hydro is not requesting the recovery of carrying costs on the forgone distribution revenue in this Application, nor recovery from the GS >50kW, street lighting, sentinel lighting and unmetered scattered load classes, as they are unaffected. Table 2 below summarizes the forgone revenue by customer class:

Table 2

Forgone Revenue by Class

Rate Group	Metrics	2005 Reductions	2005 Rate	$	2006 Cumulative	2006 Rate	Total $	2007 Cumulative	2007 Rate	Total $	LRAM Total $ Recovery	3 Year Reduction Kwh Direct
Residential	kWh	178,268	$ 0.0108	$ 1,925.29	391,364	$ 0.0122	$ 4,774.64	391,364	$ 0.0123	$ 4,813.78	$ 11,514	960,996
GS <50 kW	kWh	19,018	$ 0.0105	$ 199.69	19,018	$ 0.0119	$ 226.31	19,018	$ 0.0120	$ 228.22	$ 654	57,054
										LRAM	**$ 12,168**	1,018,050

The LRAM recovery requested, excluding the amounts referred to above, is $12,168 .

NOTL Hydro proposes to allocate the forgone distribution revenue from each class (residential and GS <50kW) to that class for recovery through a rate adder to be applied to the variable distribution rate component for both classes. As noted above, NOTL Hydro proposes to implement the rate adder over a 2 year period, from May 1, 2009 to 30 April, 2011 in order to mitigate potential customer impacts.

SHARED SAVINGS MECHANISM:

SSM amounts are calculated based on the results of the TRC test, defined as a test that "*measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the LDC's costs."*

In measuring the effectiveness of a program the TRC test examines the benefits of a program, which is typically the avoided resource costs such as electricity, with program costs which includes both the LDC's costs and the participant's costs, over the life of the program. The stream of future net benefits is net present valued ("NPV") to a single number and must be greater than zero to be cost effective.

The TRC test also provides for free ridership such that a program with a high degree of free ridership is therefore less cost effective for the LDC to pursue as the program costs will exceed the program benefits.

The amount of the SSM incentive is based on 5% of the NPV of the net benefits of NOTL Hydro CDM programs.

NOTL Hydro has calculated the SSM amount in accordance with the methodology set out in the TRC Guide. In accordance with the Guidelines for applying for the SSM incentive, NOTL Hydro is only making application for customer-focused initiatives (no "utility side" programs) that reduce the demand for electricity.

As noted above, NOTL Hydro has calculated the SSM recovery as 5% of the NPV of the net benefits for each program, in accordance with the TRC Guide. The total SSM calculated in this application amounts to $8,563 .

Table 1 below summarizes the SSM calculations by program and by customer class.

Table 1

SSM Amounts by Program and Class

Rate Group	Non-Rate Base TRC Savings	With Tax Add Back 36.12%	5% Recovery
Residential	$ 35,698	$ 55,883	$ 2,794
GS <50 kW	$ 73,700	$ 115,373	$ 5,769
	$ 109,398	**$ 171,256**	**$ 8,563**

As with the LRAM adjustment, NOTL Hydro proposes that the SSM amount arising from CDM activities in each rate class be allocated to that class, and that the SSM be recovered through a variable distribution rate rider applicable to that class. Also consistent with the LRAM rate rider, NOTL Hydro proposes to implement the variable distribution rate rider over 2 years from May 1, 2009 to 30 April, 2011 to mitigate potential customer impacts.

RELIEF REQUESTED:

NOTL Hydro proposes that the LRAM and SSM rate riders be combined into, and recovered through a single distribution rate rider as provided in Table 1 of the preceding Schedule 2, and that the total LRAM and SSM rate rider be implemented effective May 1, 2009 for a period of 2 years ending 30 April, 2011 .

NOTL Hydro notes that at page 11 of the Toronto Hydro Decision, the OEB states "The Board believes that for future claims relating to third tranche and 2006 incremental spending, the Board and stakeholders could be assisted by an independent third party review of program results, and claim amounts." NOTL Hydro submits that its claim for LRAM and SSM in the amount of $20,731 represents only 0.43% of its distribution revenue requirement and therefore does not have a material impact on distribution rates, and that any such impact has been mitigated by recovering the LRAM/SSM over 2 rate years. This can be seen in the discussion of bill impacts in Schedule 5, below. In light of the foregoing, NOTL Hydro requests approval of its proposed LRAM and SSM without being subject to a further review.

BILL IMPACTS:

NOTL Hydro proposes that the LRAM and SSM amounts be recovered over 2 years through rate riders effective May 1, 2009 until 30 April, 2011 . Table 1 below provides a summary of the impacts of the proposed LRAM and SSM adjustments on the variable distribution rate, the percent change in distribution cost, and the percent change in total bill, for the average customer in each affected rate class.

Table 1

LRAM & SSM Rate Impacts by Class

Consumption per Month	% Change Variable Rates	% Change Distribution Cost	% Change Total Bill
Residential			
1,000 kWh	0.81%	0.33%	0.09%
General Service <50kW			
2,000 kWh	0.83%	0.31%	0.09%

NOTL Hydro submits that the recovery of the LRAM and SSM adjustments over 2 years satisfactorily mitigates the rate impact to customers, and that further mitigation is not required.