

July 11 2007

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

The Corporation of the Town of Terrace Bay (the "Town") hereby applies to the Ontario Energy Board ("OEB") for an order of the OEB:

1. Granting leave to the Town to sell to Hydro One Networks Inc. the electric distribution assets which are located within the boundaries of the Town and formerly managed by the Terrace Bay Superior Wires Inc. (the "Utility"), pursuant to s. 86(1) of the *Ontario Energy Board Act, 1998*, ("the Act") and,
2. Canceling the Utility's licence to distribute electricity in the Town effective upon the closing of the proposed sale of the electric distribution assets to Hydro One Networks Inc.

And,

Hydro One Networks Inc. hereby gives notice to the OEB, pursuant to s. 81 of the Act, of its intention to acquire the distribution assets of the Town and applies to the OEB for:

3. An amendment of Hydro One Networks Inc. Electricity Distribution Licence, ED-2003-0043 to permit distribution of electricity in that portion of the Town currently served by the Utility effective upon the closing of the proposed sale of the electric distribution assets to Hydro One Networks Inc., and,
4. An order approving the rate schedules attached as Section 2.1.4 as an amendment to, and a part of, the rate schedules approved through EB-2007-0542 concerning Hydro One Networks Inc.'s distribution rate order.

The attached application adheres to the revised Filing Requirements for Mergers, Acquisitions, Amalgamations and Divestitures in the Ontario Electricity Transmission and Distribution Sector, issued by the OEB on December 1, 2006.

Pursuant to subsection 21 (4) of the Act, both applicants hereby request the disposition of this application without a hearing. This request is addressed at the end of the application.

Sincerely,

ORIGINAL SIGNED BY MICHAEL KING

Michael King, Mayor
The Corporation of the Town of Terrace Bay
P.O Box 40
31 Simcoe Plaza
Terrace Bay, ON
P0T 2W0

And

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Vice-President and Chief Regulatory Officer
Hydro One Networks Inc.
483 Bay Street, 8th Floor, South Tower
Toronto, Ontario M5G 2P5

Ontario Energy Board
Preliminary Filing Requirements
For Applications under Section 86
Of the *Ontario Energy Board Act, 1998*

INSTRUCTIONS:

All applicants must complete and file the information requested in Part I. If the transaction would result in a change in control of any of the parties to the proposed transaction, the applicant must also complete and file the information requested in Part II.

The Ontario Energy Board (the "Board") has established this form under section 13 of the *Ontario Energy Board Act, 1998* (the "Act") and requires that a proceeding under section 86 of the Act be commenced by filing this form. Please note that the Board may require information that is additional or supplementary to the information filed in this form and that the filing of the form does not preclude the applicant from filing additional or supplementary information.

For applications involving asset sales between licensed distributors or transmitters as made under section 86(1)(b) of the Act, the "Preliminary Filing Requirements for Applications Under Section 86(1)(b) of the *Ontario Energy Board Act, 1998*" form is required. For all other transactions made under section 86(1)(b), including leasing arrangements, this form should be used. If the transaction involves a leasing arrangement, the applicant must also complete and file the information requested in Part III. For transactions involving a non-licensed entity, please contact Market Operations at market.operations@oeb.gov.on.ca for further guidance.

Persons giving a Notice of Proposal under sections 80 or 81 of the Act in addition to filing an application under section 86 of the Act must also complete the "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" form in addition to this form.

Please be advised that depending on the nature of the proposed transaction, the parties to the proposed transaction may be required to apply for the cancellation of an existing licence, an amendment to an existing licence, the issuance of a new licence or any combination thereof. Such applications are to be made under separate cover as those types of applications are subject to a separate process. Parties may apply for the cancellation of an existing licence, an amendment to an existing licence, the issuance of a new licence or any combination thereof at the same time the parties apply for approval of the proposed transaction.

PART I: GENERAL MINIMUM FILING REQUIREMENTS

All applicants must complete and file the information requested in this Part.

1.1 Nature of the application

1.1.1	Please indicate the nature of the application:	Check Box	
	For leave for a transmitter or distributor to sell, lease or otherwise dispose of all or substantially all of its transmission or distribution system (s. 86(1)(a)).	X	
	For leave for a transmitter or distributor to sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public (s.86(1)(b)).		
	For leave to amalgamate with any other corporation (s. 86(1)(c)).		
	For leave to acquire voting securities that will exceed 20% of a distributor or transmitter (s. 86(2)(a)).		

	For leave to acquire control of a company that holds more than 20% of the voting securities of a transmitter or distributor (s. 86(2)(b)).		
1.1.2	In conjunction with this application, will a notice of proposal be given to the Board under Section 80 of the Act, concerning the intention of a transmitter or distributor (or its affiliate) to acquire an interest in or construct a generation facility in Ontario or to purchase shares in a generation facility in Ontario? If so, this application must be filed together with a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the <i>Ontario Energy Board Act, 1998</i> ".	No	
1.1.3	In conjunction with this application, will a notice of proposal be given to the Board under Section 81 of the Act, concerning the intention of a generator (or its affiliate) to acquire an interest in or construct a transmission or distribution facility in Ontario or to purchase shares in a transmission or distribution facility in Ontario? If so, this application must be filed together with a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the <i>Ontario Energy Board Act, 1998</i> ".	No	

1.2 Identification of the Parties

1.2.1 Applicant

Name of Applicant Terrace Bay Superior Wires Inc.		File No: (Board Use Only)	
Address of Head Office P.O. Box 40 31 Simcoe Plaza Terrace Bay, Ontario P0T 2W0 Canada		Telephone Number (807) 825-3315	
		Facsimile Number (807) 825-9576	
		E-mail Address - cao@terrace-bay.com	
Name of Individual to Contact Richard Beare Utility Manager (Acting)		Telephone Number (807) 825-3315	
		Facsimile Number (807) 825-9576	
		E-mail Address - cao@terrace-bay.com	

1.2.2 Other Parties to the Transaction

If more than one attach list

Name of Other Party Hydro One Networks Inc.		Board Use Only	
Address of Head Office 483 Bay Street South Tower, 8th Floor Toronto, Ontario M5G 2P5		Telephone Number (416) 345-5913	
		Facsimile Number (416) 345-5866	
		E-mail Address - Glen.MacDonald@HydroOne.com	
Name of Individual to Contact Mr. Glen MacDonald		Telephone Number (416) 345-5913	
		Facsimile Number (416) 345-5866	
		E-mail Address – Glen.MacDonald@HydroOne.com	
1.2.3	Please attach a list of the officers, directors and shareholders of each of the parties to the proposed transaction. Hydro One Networks Inc. Directors: Laura Formusa (Chair) Beth Summers Tom Goldie Officers: Laura Formusa (President and CEO) Beth Summers (Chief Financial Officer) Joe Agostino (General Counsel – Acting) Maureen Wareham (Secretary – Acting) Hydro One Networks Inc. is 100% owned by Hydro One Inc., which in turn is 100% owned by the Province of Ontario. Terrace Bay Superior Wires Inc. Directors: Mike King, Board President, also Mayor of Township of Terrace Bay Mary-Clara Papineau, Board Vice President, (No shareholder affiliation) Tom Falzetta, Board Director only (No shareholder affiliation) Officers: Richard Beare , General Manager and Secretary-Treasurer for the Board (Acting) (No shareholder affiliation) Margaret Hartling, Deputy-Secretary-Treasurer for the Board, and also Treasurer for the Township of Terrace Bay Terrace Bay Superior Wires Inc. is 100% owned by the Corporation of the Township of Terrace Bay.		

1.2.4	Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates. Attached	

1.3 Description of the Businesses of the Each of the Parties

1.3.1	Please attach a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates"). Hydro One Networks Inc. (Excerpted from Annual Information Form, dated February 16, 2007) Our distribution business, which represented approximately \$5.17 billion of our total assets of \$12.23 billion as at December 31, 2006, distributes electricity through our approximately 124,700 circuit-kilometre low-voltage distribution system, including phase multipliers, to municipalities and in rural areas. Customers of our distribution business include 34 local distribution companies that are not directly connected to our transmission system, 48 large industrial customers and approximately 1.3 million rural and urban customers including Hydro One Brampton Networks Inc. and Hydro One Remote Communities Inc. Hydro One Brampton Networks Inc. is our urban distribution company, serving approximately 120,000 customers in the GTA with approximately 4,845 circuit-kilometres of lines with phase multiplier. We also operate through our subsidiary, Hydro One Remote Communities Inc., 18 small, regulated generation and distribution systems in 20 remote communities across Northern Ontario that are not connected to Ontario's electricity grid. Terrace Bay Superior Wires Inc. (Excerpted from Financial Statements, dated December 31, 2006) Terrace Bay Superior wires Inc. is a wholly-owned subsidiary company of the Corporation of the Township of Terrace Bay, providing electrical distribution services to the inhabitants of the Township of Terrace Bay, as regulated by the Ontario Energy Board ("OEB").	
1.3.2	Please attach a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable. Attached is Hydro One Networks Inc. Electricity Distribution Licence ED-2003-0043. See Schedule 1 for Definition of Distribution Service Area. Also, the attached map is a representation of Hydro One Networks' Distribution service territory. It is not a substitute for the written description in Hydro One Networks' Electricity Distribution Licence ED-2003-0043. The map is accurate where LDC boundaries conform to existing or former municipal boundaries but is only a best-effort representation in locations where there have been annexations or for other reasons the LDC boundaries are different from current or former municipal boundaries. Excerpted from Schedule 1 of the Terrace Bay Superior Wires Inc. Electricity Distribution Licence ED-2002-0543 The Town site of the Township of Terrace Bay covering the area starting at Aquasabon River on the western boundary to a point on Hwy 17, 1 KM east of Mill Road in the Township of Terrace Bay, south to Lake Superior and north to the municipal boundary but excluding the pulp and paper mill; as served by the former Terrace Bay Hydro, now Terrace Bay Superior Wires Inc. (incorporated in October 2000), as of April 1, 1999.	
1.3.3	Please attach a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction. Attached	

1.3.4	Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction. Hydro One Networks Inc. ("Hydro One") geographic service area will be amended to include the Town of Terrace Bay ("Town"), and the license and geographic service area for Terrace Bay Superior Wires Inc. ("Corporation") will be cancelled.	

1.4 Description of the Proposed Transaction

1.4.1	Please attach a detailed description of the proposed transaction. Hydro One will acquire the operating assets of the Corporation for cash consideration. Hydro One, the Corporation and the Town have agreed to exclude the following categories of assets that the Town wishes to retain. The parties have also agreed to make certain post-closing adjustments to adjust the final purchase price, based on the levels of working capital and net fixed assets at closing, as disclosed on the Corporation's audited financial statements for the period ending at the time of closing. Excluded Assets from the transaction – 1808 Buildings and Fixtures 1915 Office Furniture and Equipment 1920 Computer Equipment – Hardware 1925 Computer Software	
1.4.2	Please attach the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction. Hydro One will pay cash for the operating assets of the Corporation. The final dollar amount will be finalized and released after the post closing adjustments. One Hundred Thousand dollars (\$100,000) of the consideration will be paid as a deposit with the balance due on closing, subject to 20% of the Purchase Price being held in escrow for post-closing adjustments, and adjustments due to encumbrances or other claims.	
1.4.3	Please attach the financial statements (including balance sheet, income statement, and sources and uses of funds) of the parties to the proposed transaction for 2 complete years prior to the proposed transaction. The Applicant's financial statements are attached. For Hydro One, see item 1.5.1	
1.4.4	Please attach the pro forma financial statements of each of the parties reflecting completion of the proposed transaction for the first full year following the year of the transaction. Since the proposed transaction is an asset purchase, no new "proposed entity" will be created. The Distribution Facilities to be acquired by Hydro One by the asset purchase will be integrated together with its already existing distribution facilities. The future financial statements of Hydro One Networks Inc. will not be materially affected as the proposed transaction represents less than 1% of Hydro One's 2006 distribution utility rate base.	

1.5 Other Information

1.5.1	Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years. The complete package of information filed by Hydro One Inc. represents about 70 different documents per year. The Annual Report and Annual Information Form are attached as Schedule 1.5.1. Further information is available at the SEDAR website – http://www.sedar.com/DisplayCompanyDocuments.do?lang=EN&issuerNo=00014266 The Corporation does not file any material with securities commissions	
1.5.2	Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction. Asset Purchase Agreement Holdback Escrow Agreement	
1.5.3	Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.) Hydro One Networks Inc. ED-2003-0043 Terrace Bay Superior Wires Inc. ED-2002-0543 Hydro One will be compliant with all applicable licenses, codes and rules after the completion of the proposed transaction. Upon closing, the Terrace Bay Superior Wires will apply to cancel its license as a Local Distribution Company in Ontario.	
1.5.4	Please explain whether the proposed transaction will cause a change of control, of any of the transmission or distribution system assets, at any time, during or by the end of the transaction. If yes, please complete Part II. The proposed transaction will result in a change in control as explained in PART II below.	

PART II: ADDITIONAL FILING REQUIREMENTS FOR CHANGE IN CONTROL

If the proposed transaction would result in a change in control of any of the parties to the proposed transaction, this Part must be completed.

2.1 Consumer Protection

2.1.1	Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service. Customers of the Corporation will benefit in the long term from access to the greater depth of expertise of Hydro One in the management and maintenance of the distribution system and in the economies of scale that Hydro One can realize due to its size. Hydro One will follow all OEB guidelines with respect to rates as if the Corporation was to continue operating independently until we can harmonize rates. This may occur at Hydro One Distribution's next rate re-basing. For Hydro One's existing customers, they will also benefit in the long term because fixed costs of operations will be spread over a wider customer base. The decision to sell the assets of the Corporation was taken by the Town after a review of the options. With the assistance of advisers, Council gave thorough consideration of the costs, benefits and risks of various alternatives and decided that selling the Corporation's assets to Hydro One was in the best interest of the Corporation's customers. The Council, as the shareholder of the Corporation, was elected to represent the interests of the citizens of the Town. Hydro One will utilize personnel from its Marathon Operating Centre to provide emergency response for outages and necessary capital work or maintenance activities. Hydro One already serves customers surrounding portions of the Corporation's service territory. The Marathon Operating Centre is located 80 km from the Town. Billing, collecting and customer service inquiries will be handled by Hydro One's Customer Care Centre in Markham. This will give the customers of the Corporation access to the same level of customer service and billing systems that Hydro One's existing customers currently receive.	
2.1.2	Please describe the steps, including details of any capital expenditure plans that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction. The acquired assets will be fully integrated with Hydro One's distribution assets to ensure the safe and secure operations and system integrity for both the acquired customers and the neighbouring Hydro One customers. The acquisition will not adversely affect the applicability of any Act or Regulation related to safety or system integrity.	
2.1.3	Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times. In performing maintenance on the acquired system, Hydro One distribution system standards will be used. Hydro One will thereby be able to serve the customers of the Corporation with the same level of service Hydro One provides its existing customers by virtue of the existing customer service practices and policies of Hydro One. Electric utility service to customers currently served by the Corporation will remain subject to OEB regulation through the regulation of Hydro One service and rates. Hydro One will utilize personnel from its Marathon Operating Centre to provide emergency response for outages and necessary capital work or maintenance activities. Hydro One	

	already serves customers surrounding portions of the Corporation's service territory. The Marathon Operating Centre is located 80 km from the Town. This is significantly closer to Town than the location of the current contract service provider (Thunder Bay) performing all operating and maintenance work for the Applicant.	
2.1.4	Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan. Hydro One will maintain the Corporation's approved Distribution rates and other pass-through charges as they have been approved by the OEB (Attached as Schedule 2.1.4). Hydro One will apply all OEB guideline's with respect to future rate adjustments to the distribution business of the Corporation in the same manner as the Corporation would have done if they had not been acquired by Hydro One and until the Corporations' rates are harmonized with Hydro One's rates. As soon as feasible, Hydro One will harmonize the Corporation's rates with its own distribution rates and other pass-through charges. Hydro One may apply for harmonization at its next distribution's rate re-basing. With respect to Street Light rates and Miscellaneous charges, Hydro One requests that the Board approve the use of the approved Hydro One Street Light and Miscellaneous charges as per the Board's Rate Order in EB-2007-0542 dated April 30, 2007.	
2.1.5	Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances) and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs. Incremental costs associated with the transaction include the integration costs to transfer the customers into Hydro One customer and outage management systems, plus initial costs to bring equipment up to Hydro One standards. These costs will be financed from the general funds of Hydro One.	
2.1.6	Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction. See 2.1.4	
2.1.7	Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction. Benefits to customers will include access to 24 hour outage response process, access to Conservation and Demand Management programs, including Smart Meter plans, 24 hour web access to their accounts, plus an option for e-billing via the internet.	

2.2 Economic Efficiency

2.2.1	Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service. Hydro One will be able to eliminate most of the administrative costs of the Applicant for centralized functions and perform them with existing staff and systems within Hydro One. Customers will be served by an existing service centre closer to town than the location of the current contract service provider performing all operating and maintenance work for the Corporation.	

2.3 Financial Viability

2.3.1	Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels. Hydro One and the Town have entered into an Asset Purchase Agreement whereby Hydro One will be purchasing all of the operating assets of the Corporation related to the business of distributing electrical power and energy to the customers within the boundaries of the Town. In formulating the decision to sell the assets of the Corporation to Hydro One, the Town relied heavily on the recommendation of the directors of the Corporation and the report of the Chief Administrative Officer of the Town. The Corporation's directors met on March 30, 2007 to review the Hydro One offer and recommended acceptance of the offer. The Chief Administrative Officer similarly recommended sale of the assets of the Corporation to Hydro One at the March 26, 2007 regular Town Council Meeting. Resolution CR 124-2007 was approved by Council providing authorization to accept the offer from Hydro One. A copy of the resolution is attached as 2.3.1. The Town is satisfied that the price to be received is fair and reasonable. The Town also retained the services of Grant Thornton LLP and O'Flynn Weese LLP, Barrister and Solicitors to advise and assist in conducting the sale of the assets of the Corporation. The Town excluded certain assets from the transaction. These assets and their respective Net Book Value include various PCB Storage and Information Technology assets worth \$41,000. As the purchaser, Hydro One used the book value of assets in determining the value of a business entity such as the Corporation. Hydro One considered other components of the financial statements as well as cash flow projections, an assessment of asset condition, one-time costs of integration and potential efficiency gains in assessing the value of the business. Further, prior to concluding the Asset Purchase Agreement, an extensive due diligence assessment will be carried out which is reflected in any necessary adjustments to the valuation. Hydro One has assumed that future rates for the Corporation's customers will be determined based on guidelines set out by the OEB.	
2.3.2	If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility. The transaction does not represent a significant premium on book value.	
2.3.3	Please provide details of the financing of the proposed transaction. The purchase will be financed through a combination of debt and equity. The proposed transaction will not impair the financial viability of Hydro One. The purchase represents less than 1% of Hydro One's 2006 distribution utility rate base.	
2.3.4	Please outline the capital (debt /equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to <u>allow the Board to assess any potential impacts on the utility's financial viability</u>, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed. The financial measures of Hydro One will not change materially as a result of this transaction.	

2.3.5	Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities. Under the Asset Purchase Agreement the Town has represented and warranted that the property over which the Distribution Facilities are located is not contaminated with any hazardous substances as a result of the operations or activities of the Corporation relating to or associated with the Distribution Facilities and/or as a result of any other activity of any third party which the Corporation knew about and, that except for PCBs contained in the transformers which are in service and which form part of the Distribution Facilities, the Distribution Facilities do not contain any hazardous substances. This representation and warranty survives for a 3-year period following the closing of the transaction. Hydro One manages numerous similar assets throughout the Province and has programs in place to deal with any relevant safety and environmental matters.	

2.4 Other

2.4.1	If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction. Attached	
2.4.2	Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates. There are no proceedings by any government agency. The only outstanding action is a class action suit against all Ontario MEUs regarding late payment charges.	
2.4.3	Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility. Current net metering thresholds per Attachment B of Notice of Amendment to the Distribution System Code that came into force February 10, 2006: Hydro One Networks Inc. 14,330 kW Terrace Bay Superior Wires Inc. 48 kW There are no special circumstances that warrant using a different methodology to determine the net metering threshold.	
2.4.4	Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity. None provided.	

PART III: ADDITIONAL FILING REQUIREMENTS REGARDING LEASE TRANSACTIONS

If the proposed transaction involves a leasing arrangement, this Part must be completed.

3.1.1	In addition to the information provided in section 1.3.4, please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant. Not applicable.	

How to Contact the Ontario Energy Board

The Ontario Energy Board is located at:

P.O. Box 2319
2300 Yonge Street, Suite 2701
Toronto, Ontario
M4P 1E4

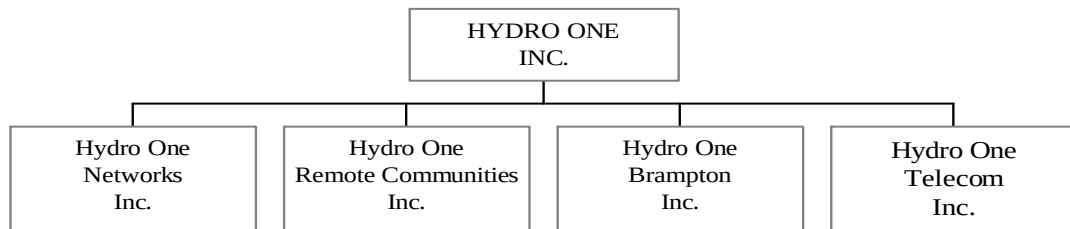
Telephone:	416-481-1967
Toll Free Number:	1-888-632-6273
Fax:	416-440-7656
Website:	http://www.oeb.gov.on.ca
Board Secretary's e-mail address:	boardsec@oeb.gov.on.ca

SECTION - 1.2.4

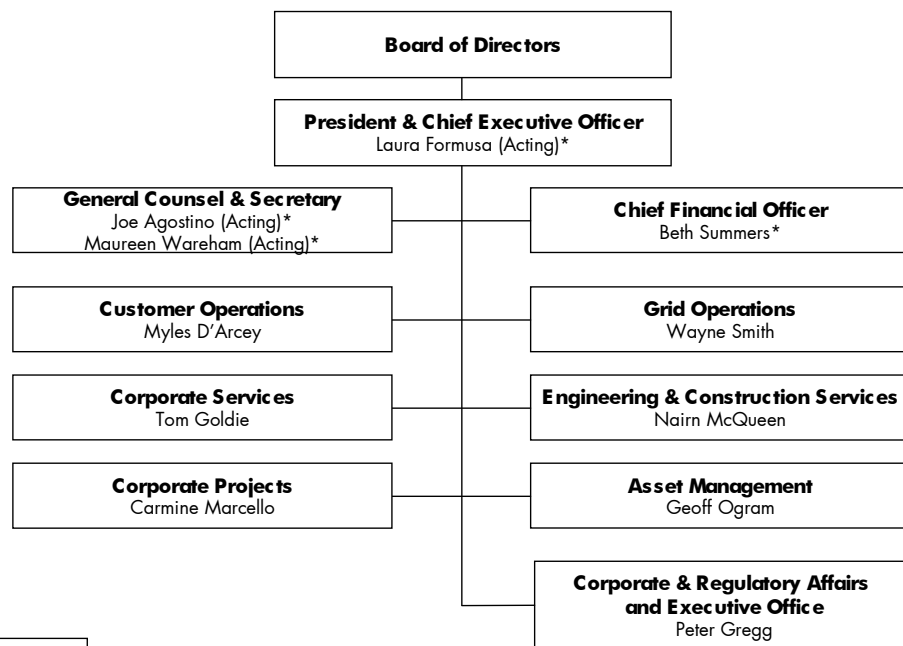
Corporate Organization Charts For Hydro One Inc And Hydro One Networks Inc.

The following provides the Hydro One Inc. and Hydro One Networks Inc. Organization Charts.

Please note - As per the Ontario Business Corporations Act,, Hydro One Inc. is an Affiliate of Ontario Power Generation.

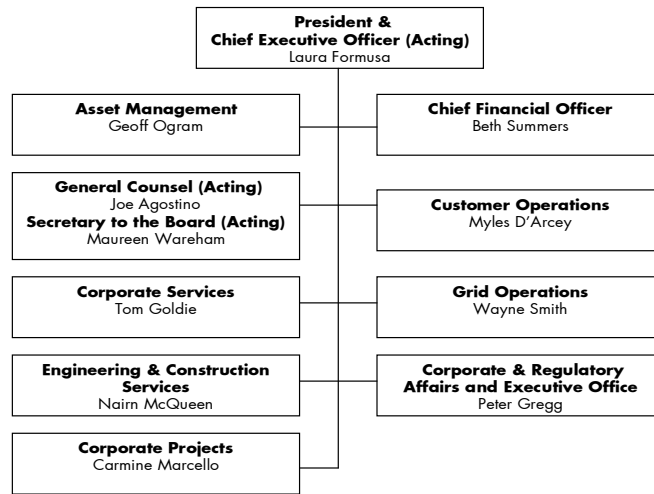


Hydro One Senior Management



As of April, 2007
* Officers of Hydro One Inc.

Hydro One Networks Inc.



As of April, 2007

There is no organization chart available for Terrace Bay Superior Wires. There are no relationships between Hydro One Networks Inc. and Terrace Bay Superior Wires Inc., nor any of their affiliates.

SECTION - 1.3.2

**Hydro One Networks Inc.
Electricity Distribution Licence**



Electricity Distribution Licence

ED-2003-0043

Hydro One Networks Inc.

Valid Until

September 28, 2024

Mark C. Garner
Managing Director, Market Operations
Ontario Energy Board
Date of Issuance: September 29, 2004
Date of Amendment: October 12, 2005

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

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1 Definitions

In this Licence:

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

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

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

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

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

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

"Licensee" means Hydro One Networks Inc.

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

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

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

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

"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;

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

“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;

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

2 Interpretation

- 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 that is not a holiday.

3 Authorization

- 3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:
- a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;
 - 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
 - c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

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

5 Obligation to Comply with Codes

- 5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:
- a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

- b) the Distribution System Code;
- c) the Retail Settlement Code; and
- d) the Standard Supply Service Code.

5.2 The Licensee shall:

- a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and
- b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

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

7 Obligation to Connect

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

- a) the building lies along any of the lines of the distributor's distribution system; and
- b) the owner, occupant or other person in charge of the building requests the connection in writing.

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

- a) the building is within the Licensee's service area as described in Schedule 1; and
- b) the owner, occupant or other person in charge of the building requests the connection in writing.

- 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.

- 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.

8 Obligation to Sell Electricity

- 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.

9 Obligation to Maintain System Integrity

- 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.

10 Market Power Mitigation Rebates

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

11 Distribution Rates

- 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.

12 Separation of Business Activities

- 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.

13 Expansion of Distribution System

- 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.
- 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.

14 Provision of Information to the Board

- 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.
- 14.2 Without limiting the generality of paragraph 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.
- 14.3 The Licensee shall:
- a) immediately notify the Board in writing of the notice; and
 - b) provide a plan to the Board as soon as possible, but no later than ten (10) days after the receipt of the notice, as to how the affected distribution services will be maintained in compliance with the terms of this licence.

15 Restrictions on Provision of Information

- 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.
- 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:
- a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;
 - b) for billing, settlement or market operations purposes;
 - c) for law enforcement purposes; or
 - d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.
- 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.
- 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.
- 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.

16 Customer Complaint and Dispute Resolution

- 16.1 The Licensee shall:
- a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;
 - b) publish information which will make its customers aware of and help them to use its dispute resolution process;
 - 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;
 - d) give or send free of charge a copy of the process to any person who reasonably requests it; and
 - 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.

17 Term of Licence

- 17.1 This Licence shall take effect on September 29, 2004 and expire on September 28, 2024. The term of this Licence may be extended by the Board.

18 Fees and Assessments

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

19 Communication

- 19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.
- 19.2 All official communication relating to this Licence shall be in writing.
- 19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:
- a) when delivered in person to the addressee by hand, by registered mail or by courier;
 - b) ten (10) business days after the date of posting if the communication is sent by regular mail; and
 - c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

- 20.1 The Licensee shall:
- a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and
 - b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

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

1. Municipalities as set out in Appendix B – Tab 1.
2. First Nation Reserves as set out in Appendix B – Tab 2.
3. Unorganized Townships as set out in Appendix B – Tab 3.
4. Municipalities where areas are served by the Licensee and other distributors as set out in Appendix B – Tab 4.
5. Consumers located outside the municipalities served by the Licensee as set out in Appendix B – Tab 5.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

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.

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

SCHEDULE 3 LIST OF CODE EXEMPTIONS

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

The Licensee is exempt from the requirements of section 2.4.28 of the Distribution System Code until November 30, 2005.

APPENDIX A MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

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

“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;

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

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

2. Information Given to IMO

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

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.

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.

3. Pass Through of Rebate

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:

- 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;
- 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
- c embedded distributors to whom the distributor distributes electricity.

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.

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:

"ONTARIO POWER GENERATION INC. rebate"

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.

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

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.

APPENDIX B TABS 1 - 5 SERVICE AREAS

Tab 1 - MUNICIPALITIES

1

Name of Municipality: Township of Addington Highlands

Formerly Known As: Township of Denbign, Abinger and Ashby, Township of Anglesea and Effingham, Kaladar, as at December 31, 1999.

2

3

Name of Municipality: Township of Adelaide Metcalfe

Formerly Known As: Township of Adelaide, Township of Metcalfe, as at December 31, 2000.

4

Name of Municipality: Township of Adjala-Tosorontio

Formerly Known As: Portions of the Township of Adjala, Township of Tosorontio, Township of Sunnidale, as at December 31, 1993.

5

Name of Municipality: Township of Admaston/Bromley

Formerly Known As: Township of Admaston, Township of Bromley, as at December 31, 1999.

6

Name of Municipality: Township of Alberton as at March 31, 1999.

Formerly Known As: Same.

7

Name of Municipality: Township of Algonquin Highlands, (Formerly known as Township of Sherborne, Stanhope, McClintock, Livingstone, Lawrence and Nightingale).

Formerly Known As: Township of Sherborne et al, Township of Stanhope, as at December 31, 2000.

8

Name of Municipality: Township of Alnwick/Haldimand

Formerly Known As: Township of Alnwick, Township of Haldimand, as at December 31, 2000.

9

Name of Municipality: Township of Amaranth as at March 31, 1999.

Formerly Known As: Same.

10

Name of Municipality: Township of The Archipelago as at March 31, 1999.

Formerly Known As: Conger, Cowper, Harrison, Henvey, Wallbridge plus geographic/unorganized townships and unsurveyed areas.

11

Name of Municipality: Township of Armour as at March 31, 1999.

Formerly Known As: Same.

12

Name of Municipality: Township of Armstrong as at March 31, 1999.

Formerly Known As: Same.

13

Name of Municipality: Town of Arnprior as at March 31, 1999.

Formerly Known As: Same.

14

Name of Municipality: Municipality of Arran-Elderslie

Formerly Known As: Township of Arran, Township of Elderslie, Town of Chesley, Village of Tara, Village of Paisley, as at December 31, 1998.

15

Name of Municipality: Township of Ashfield-Colborne-Wawanosh

Formerly Known As: Township of Ashfield, Township of West Wananosh, Township of Colborne, as at December 31, 2000.

16

Name of Municipality: Township of Assiginack as at March 31, 1999.

Formerly Known As: Same.

17

Name of Municipality: Township of Athens

Formerly Known As: Township of Rear of Yonge and Escott, Village of Athens, as at December 31, 2000.

18

Name of Municipality: Township of Augusta as at March 31, 1999.

Formerly Known As: Same.

19

Name of Municipality: Township of Baldwin as at March 31, 1999.

Formerly Known As: Same.

20

Name of Municipality: Town of Bancroft

Formerly Known As: Town of Bancroft, Township of Dungannon, as at December 31, 1998.

21

Name of Municipality: Township of Barrie Island as at March 31, 1999.

Formerly Known As: Same.

22

Name of Municipality: Municipality of Bayham

Formerly Known As: Township of Baymen, Village of Port Burwell, Village of Vienna, as at December 31, 1997.

23

Name of Municipality: Township of Beckwith as at March 31, 1999.

Formerly Known As: Same.

24

Name of Municipality: Township of Billings as at March 31, 1999.

Formerly Known As: Same.

25

Name of Municipality: Township of Black River-Matheson as at March 31, 1999.

Formerly Known As: Same.

26

Name of Municipality: Township of Blandford-Blenheim as at March 31, 1999.

Formerly Known As: Same.

27

Name of Municipality: Town of Blind River as at March 31, 1999.

Formerly Known As: Same.

28

Name of Municipality: Township of Bonfield as at March 31, 1999.

Formerly Known As: Same.

29

Name of Municipality: Township of Bonnechere Valley

Formerly Known As:	Village of Eganville, Township of Grattan, Township of Sebastopol, Township of South Algona, as at December 31, 2000.	30
Name of Municipality:	Township of Brethour as at March 31, 1999.	
Formerly Known As:	Same.	31
Name of Municipality:	Municipality of Brighton	
Formerly Known As:	Town of Brighton, Township of Brighton, as at December 31, 2001.	32
Name of Municipality:	City of Brockville as at March 31, 1999.	
Formerly Known As:	Same.	33
Name of Municipality:	Township of Brudenell, Lyndoch and Raglan	
Formerly Known As:	Township of Brudenell and Lyndoch, Township of Raglan, as at December 31, 1998.	34
Name of Municipality:	Township of Burpee and Mills	
Formerly Known As:	Township of Burpee, Unorganized Twp of Mills, as at December 31, 1997.	35
Name of Municipality:	Town of Caledon	
Formerly Known As:	Township of Albion, Township of Caledon, Village of Bolton, Village of Caledon East, Township of Chinguacousy (part), as at December 31, 1973.	

36

Name of Municipality: Township of Calvin as at March 31, 1999.

Formerly Known As: Same.

37

Name of Municipality: Town of Carleton Place as at March 31, 1999.

Formerly Known As: Same.

38

Name of Municipality: Township of Carling as at March 31, 1999.

Formerly Known As: Same.

39

Name of Municipality: Township of Carlow/Mayo

Formerly Known As: Township of Carlow, Township of Mayo, as at December 31, 2000.

40

Name of Municipality: Township of Casey as at March 31, 1999.

Formerly Known As: Same.

41

Name of Municipality: Township of Cavan-Millbrook-North Monaghan

Formerly Known As: Township of Cavan, Township of North Monaghan, Village of Millbrook, as at December 31, 1997.

42

Name of Municipality: Township of Central Frontenac

Formerly Known As: Township of Hinchinbrooke, Township of Kennebec, Township of Olden, Township of Oso, as at December 31, 1997.

43

Name of Municipality: Township of Central Manitoulin

Formerly Known As: Twp. Of Carnarvon, Unorganized Twp of Sandfield, as at April 30, 1997.

44

Name of Municipality: Municipality of Centre Hastings

Formerly Known As: Village of Madoc, Township of Huntingdon, as at December 31, 1997.

45

Name of Municipality: Township of Chamberlain as at March 31, 1999.

Formerly Known As: Same.

46

Name of Municipality: Township of Champlain

Formerly Known As: Village of L'Original, Township of West Hawkesbury, Township of Longueuil, Town of Vankleek Hill, as at December 31, 1997.

47

Name of Municipality: Township of Chapple as at March 31, 1999.

Formerly Known As: Same.

48

Name of Municipality: Municipality of Charlton and Dack

Formerly Known As: Town of Charlton, Township of Dack, as at December 31, 2002.

49

Name of Municipality: Township of Chatsworth

Formerly Known As: Village of Chatsworth, Township of Holland, Township of Sullivan, as at December 31, 1999.

50

Name of Municipality: Township of Chisolm as at March 31, 1999.

Formerly Known As: Same.

51

Name of Municipality: City of Clarence-Rockland

Formerly Known As: Town of Rockland, Township of Clarence, as at December 31, 1997.

52

Name of Municipality: Town of Cobalt as at March 31, 1999.

Formerly Known As: Same.

53

Name of Municipality: Township of Cockburn Island as at March 31, 1999.

Formerly Known As: Same.

54

Name of Municipality: Township of Coleman as at March 31, 1999.

Formerly Known As: Same.

55

Name of Municipality: Township of Conmee as at March 31, 1999.

Formerly Known As: Same.

56

Name of Municipality: Township of Dawn-Euphemia

Formerly Known As: Township of Dawn, Township of Euphemia, as at December 31, 1997.

57

Name of Municipality: Township of Dawson

Formerly Known As: Township of Atwood, Township of Blue, Township of Worthington, Township of Dilke, as at December 31, 1996.

58

Name of Municipality: Town of Deep River as at March 31, 1999.

Formerly Known As: Same.

59

Name of Municipality: Town of Deseronto as at March 31, 1999.

Formerly Known As: Same.

60

Name of Municipality: Township of Dorion as at March 31, 1999.

Formerly Known As: Same.

61

Name of Municipality: Township of Douro-Dummer

Formerly Known As: Township of Douro, Township of Dummer, as at December 31, 1997.

62

Name of Municipality: Township of Drummond/North Elmsley

Formerly Known As: Township of Drummond, Township of North Elmsley, as at December 31, 1997.

63

Name of Municipality: City of Dryden

Formerly Known As: Town of Dryden, Township of Barclay.

64

Name of Municipality: Township of Dysart et al as at March 31, 1999.

Formerly Known As: Same.

65

Name of Municipality: Municipality of Ear Falls as at March 31, 1999.

Formerly Known As: Same.

66

Name of Municipality: Township of East Ferris as at March 31, 1999.

Formerly Known As: Same.

67

Name of Municipality: Township of East Garafraxa as at March 31, 1999.

Formerly Known As: Same.

68

Name of Municipality: Township of East Hawkesbury as at March 31, 1999.

Formerly Known As: Same.

69

Name of Municipality: Township of Elizabethtown-Kitley

Formerly Known As: Township of Kitley, Township of Elizabethtown as at December 31, 2000.

70

Name of Municipality: City of Elliott Lake as at March 31, 1999.

Formerly Known As: Same.

71

Name of Municipality: Township of Emo, as at March 31, 1999.

Formerly Known As: Same.

72

Name of Municipality: Township of Englehart as at March 31, 1999.

Formerly Known As: Same.

73

Name of Municipality: Township of Enniskillen as at March 31, 1999.

Formerly Known As: Same.

74

Name of Municipality: Town of Erin

Formerly Known As: Township of Erin, Village of Erin, as at December 31, 1997.

75

Name of Municipality: Township of Ewantural as at March 31, 1999.

Formerly Known As: Same.

76

Name of Municipality: Township of Faraday as at March 31, 1999.

Formerly Known As: Same.

77

Name of Municipality: Township of Fauquier-Strickland as at March 31, 1999.

Formerly Known As: Same.

78

Name of Municipality: Municipality of French River

Formerly Known As: Township of Cosby, Township of Mason, Township of Martland, geographic/unorganized townships of Delamere, Hoskin and Scollard in whole and Bigwood, Cherriman and Haddo in part, as at December 31, 1998.

79

Name of Municipality: Township of Front and Yonge as at March 31, 1999.

Formerly Known As: Same.

80

Name of Municipality: Township of Galway-Cavendish and Harvey

Formerly Known As: Township of Galway and Cavandish, Township of Harvey, as at December 31, 1997.

81

Name of Municipality: Township of Gauthier as at March 31, 1999.

Formerly Known As: Same.

82

Name of Municipality: Township of Georgian Bay as at March 31, 1999.

Formerly Known As: Township of Freeman, Township of Gibson, Township of Baxter.

83

Name of Municipality: Township of Georgian Bluffs

Formerly Known As: Township of Derby, Township of Keppel, Township of Sarawak, as at December 31, 2000.

84

Name of Municipality: Town of Georgina as at March 31, 1999.

Formerly Known As: Township of North Gwillimbury, Township of Georgina.

85

Name of Municipality: Township of Gillies as at March 31, 1999.

Formerly Known As: Same.

86

Name of Municipality: Township of Gordon as at March 31, 1999.

Formerly Known As: Same.

87

Name of Municipality: Town of Gore Bay as at March 31, 1999.

Formerly Known As: Same.

88

Name of Municipality: Township of Greater Madawaska

Formerly Known As: Township of Bagot, Blythfield and Brougham, Township of Griffith, and Matawatchan, (Jan 1998: Township of Bagot and Blythfield, Township of Brougham amalgamated into Township of Bagot, Blythfield and Brougham), as at December 31, 2000.

89

Name of Municipality: Town of Greater Napanee

Formerly Known As: Township of Adolphustown, Township of North Fredericksburgh, Township of South Fredericksburgh, Township of Richmond, Town of Napanee, as at December 31, 1997.

90

Name of Municipality: Municipality of Greenstone

Formerly Known As: Town of Geraldton, Town of Longlac, Township of Beardmore, Township of Nakina, as at December 31, 2000.

91

Name of Municipality: Municipality of Grey Highlands

Formerly Known As: Township of Artemesia, Township of Euphrasia Village of Markdale, Township of Osprey, as at December 31, 2000.

92

Name of Municipality: Township of Hamilton as at March 31, 1999.

Formerly Known As: Same.

93

Name of Municipality: Township of Harley as at March 31, 1999.

Formerly Known As:	Same.	94
Name of Municipality:	Township of Harris as at March 31, 1999.	
Formerly Known As:	Same.	95
Name of Municipality:	Municipality of Hastings Highlands	
Formerly Known As:	Township of Bangor, Wicklow and McClure, Township of Herschel, Township of Monteagle, as at December 31, 2000.	96
Name of Municipality:	Township of Havelock-Belmont-Methuen	
Formerly Known As:	Township of Belmont and Methuen, Village of Havelock, as at December 31, 1997.	97
Name of Municipality:	Township of Head, Clara and Maria, as at March 31, 1999.	
Formerly Known As:	Same.	98
Name of Municipality:	Municipality of Highland East	
Formerly Known As:	Township of Bicraft, Township Cardiff, Township of Glamorgan, Township of Monmouth, as at December 31, 2000.	99
Name of Municipality:	Township of Hilliard as at March 31, 1999.	
Formerly Known As:	Same.	100
Name of Municipality:	Township of Hornpayne as at March 31, 1999.	
Formerly Known As:	Same.	

101

Name of Municipality: Township of Horton as at March 31, 1999.

Formerly Known As: Same.

102

Name of Municipality: The Township of Howick as at March 31, 1999.

Formerly Known As: Same.

103

Name of Municipality: Township of Hudson as at March 31, 1999.

Formerly Known As: Same.

104

Name of Municipality: Township of Ignace as at March 31, 1999.

Formerly Known As: Same.

105

Name of Municipality: Township of James as at March 31, 1999.

Formerly Known As: Same.

106

Name of Municipality: Township of Joly as at March 31, 1999.

Formerly Known As: Same.

107

Name of Municipality: The City of Kawartha Lakes

Formerly Known As: County of Victoria, Town of Lindsay, Municipality of Bobcaygeon/ Verulam, Village of Fenelon Falls, Village of Omemee, Village of Sturgeon Point, Village of Woodville, Township of Bexley, Township of Carden/Dalton, Township of Eldon, Township of Emily, Township of Fenelon, Township of Laxton, Digby and Longford, Township Manvers, Township of Mariposa, Township of Ops, Township of Somerville, (Jan 2000: Township of Carden , Township of Dalton amalgamated into Township of Carden/Dalton), (Jan 2000; Village of Bobcaygeon/Township of Verulam amalgamated into the Municipality of Bobcaygeon/Verulam), as at December 31, 2000.

108

Name of Municipality: Town of Kearney as at March 31, 1999.

Formerly Known As: Same.

109

Name of Municipality: Township of Kerns as at March 31, 1999.

Formerly Known As: Same.

110

Name of Municipality: Municipality of Killarney

Formerly Known As: Townships of Rutherford and George Island and the geographic/unorganized townships of, Allen, Atlee, Goschen, Hansen, Killarney, Kilpatrick, Sale, Struthers, Travers, and portions of the geographic/unorganized townships of Bigwood, Carlyle, Humboldt, Mowat, and unsurveyed territory and islands, as at Deember 31, 1998.

111

Name of Municipality: Township of King as at March 31, 1999.

Formerly Known As: Same.

112

Name of Municipality: Town of Kirkland Lake as at March 31, 1999.

Formerly Known As: Same.

113

Name of Municipality: Township of La Vallee as at March 31, 1999.

Formerly Known As: Same.

114

Name of Municipality: Township of Lake of Bays as at March 31, 1999.

Formerly Known As: Township of McLean, Township of Ridout, Township of Franklin, Township of Sinclair, Township of Finlayson.

115

Name of Municipality: Township of Lake of the Woods

Formerly Known As: Township of McCrosson and Tovell, Township of of Morson, unorganized islands in Kenora District and Rainy River District, as at December 31, 1998.

116

Name of Municipality: Municipality of Lambton Shores

Formerly Known As: Village of Arkona, Town of Bosanquet, Town of Forest, Village of Grand Bend, Village of Thedford, as at December 31, 2000.

117

Name of Municipality: Township of Lanark Highlands

Formerly Known As: Township of Darling, Township of North West Lanark, (May 1997: Lavant, Dalhousie and North Sherbrook Township/ Township Lanark/Village Lanark amalgamated into Township of North West Lanark), as at June 30, 1996.

118

Name of Municipality: Township of Larder Lake as at March 31, 1999.

Formerly Known As: Same.

119

Name of Municipality: Town of Latchford as at March 31, 1999.

Formerly Known As: Same.

120

Name of Municipality: Town of Laurentian Hills

Formerly Known As: Township of Rolph, Township of Wylie and McKay, Village of Chalk River, as at December 31, 1999.

121

Name of Municipality: Township of Laurentian Valley

Formerly Known As: Township of Stafford and Pembroke, Township of Alice and Fraser, as at December 31, 1999.

122

Name of Municipality: Township of Limerick as at March 31, 1999.

Formerly Known As: Same.

123

Name of Municipality: Township of Lucan Biddulph

Formerly Known As: Village of Lucan, Township of Biddulph, Police Village of Granton, as at December 31, 1998.

124

Name of Municipality: Township of Machar as at March 31, 1999.

Formerly Known As: Same.

125

Name of Municipality: Township of Machin as at March 31, 1999.

Formerly Known As: Same.

126

Name of Municipality: Township of Madawaska Valley

Formerly Known As: Village of Barry's Bay, Township of Radcliffe, Township of Sherwood, Jones and Burns, as at December 31, 2000.

127

Name of Municipality: Township of Madoc as at March 31, 1999.

Formerly Known As: Same.

128

Name of Municipality: Township of Malahide

Formerly Known As: Township of Malahide, Township of Dorchester, Village of Springfield, as at December 31, 1997.

129

Name of Municipality: Township of Manitouwadge as at March 31, 1999.

Formerly Known As: Same.

130

Name of Municipality: Township of Mapleton

Formerly Known As: Township of Mapleton, Township of Maryborough, (Jan 1998-Village of Drayton, Township of Peel amalgamated into the Township of Mapleton), as at December 31, 1998.

131

Name of Municipality: Town of Marathon as at March 31, 1999.

Formerly Known As: Same.

132

Name of Municipality: Municipality of Markstay-Warren

Formerly Known As: Township of Hagar, Township of Ratter and Dunnet, geographic/unorganized township of Awrey and portions of the geographic/unorganized townships of Hawley, Henry, Loughrin, Street, as at December 31, 1998.

133

Name of Municipality: Municipality of Marmora and Lake

Formerly Known As: Township of Marmora and Lake, Village of Marmora, (Jan 1998: Village of Deloro, Township of Marmora and Lake amalgamated into the Township of Marmora and Lake, as at December 31, 1997.

134

Name of Municipality: Township of Matachewan as at March 31, 1999.

Formerly Known As: Same.

135

Name of Municipality: Town of Mattawa as at March 31, 1999.

Formerly Known As: Same.

136

Name of Municipality: Township of Mattawan as at March 31, 1999.

Formerly Known As: Same.

137

Name of Municipality: Township of Mattice-Val Cote as at March 31, 1999.

Formerly Known As: Same.

138

Name of Municipality: Township of McDougall

Formerly Known As: Township of McDougall, geographic/unorganized township of Ferguson, as at December 31, 1999.

139

Name of Municipality: Township of McGarry as at March 31, 1999.

Formerly Known As: Same.

140

Name of Municipality: Township of McKellar as at March 31, 1999.

Formerly Known As: Same.

141

Name of Municipality: Township of McMurrich/Monteith

Formerly Known As: Township of McMurrich, geographic/unorganized township of Monteith (eastern portion), as at December 31, 1997.

142

Name of Municipality: Township of McNab/Braeside

Formerly Known As: Township of McNab, Village Braeside, as at December 31, 1997.

143

Name of Municipality: Municipality of Meaford (formerly known as Town of Georgian Highlands)

Formerly Known As: Township of St. Vincent, Township of Sydenham, Town of Meaford, as at December 31, 2000.

144

Name of Municipality: Township of Melancthon as at March 31, 1999.

Formerly Known As: Same.

145

Name of Municipality: Village of Merrickville-Wolford

Formerly Known As: Township of Wolford, Village of Merrickville, as at December 31, 1997.

146

Name of Municipality: Township of Middlesex Centre

Formerly Known As: Township of Lobo, Township of London, Township of Delaware, Police Village of Delaware, as at December 31, 1998.

147

Name of Municipality: Township of Minden Hills

Formerly Known As: Township of Anson, Hindon and Minden, Township of Lutterworth, Township of Snowdon, as at December 31, 2000.

148

Name of Municipality: Town of Mono as at March 31, 1999.

Formerly Known As: Same.

149

Name of Municipality: Township of Montague as at March 31, 1999.

Formerly Known As: Same.

150

Name of Municipality: Township of Moonbeam as at March 31, 1999.

Formerly Known As: Same.

151

Name of Municipality: Town of Moosonee as at March 31, 1999.

Formerly Known As: Moosonee Development Board.

152

Name of Municipality: Township of Morley

Formerly Known As: Township of Morley, geographic/unorganized townships Twp's of Dewar and Sifton, as at December 31, 2003.

153

Name of Municipality: Municipality of Morris-Turnberry

Formerly Known As: Township of Morris, Township of Turnberry, as at December 31, 2000.

154

Name of Municipality: Township of Mulmur as at March 31, 1999.

Formerly Known As: Same.

155

Name of Municipality: Township of Muskoka Lakes as at March 31, 1999.

Formerly Known As: Township of Cardwell, Township of Watt, Township of Medora, Township of Monck, Township of Wood.

156

Name of Municipality: Township of Nairn and Hyman

Formerly Known As: Township of Nairn, Unorganized Township of Hyman, as at December 31, 1997.

157

Name of Municipality: The Nation Municipality

Formerly Known As: Township of Cambridge, Township of South Plantagenet, Village of St. Isidore, Township of Caledonia, as December 31, 1997.

158

Name of Municipality: Municipality of Neebing as at March 31, 1999.

Formerly Known As: Same.

159

Name of Municipality: Municipality of New Liskeard-Haileybury-Dymond

Formerly Known As: Town of New Liskeard, Town of Haileybury, Township of Dymond, as at December 31, 2003.

160

Name of Municipality: Township of Nipigon as at March 31, 1999.

Formerly Known As: Same.

161

Name of Municipality: Township of Nipissing as at March 31, 1999.

Formerly Known As: Same.

162

Name of Municipality: Township of North Algona-Wilberforce

Formerly Known As: Township of North Algona, Township of Wilberforce, as at December 31, 1998.

163

Name of Municipality: Municipality of Northern Bruce Peninsula

Formerly Known As: Township of St. Edmunds, Township of Lindsay, Township of Eastnor, Village of Lion's Head, as at December 31, 1998.

164

Name of Municipality: Township of North Dundas

Formerly Known As: Township of Mountain, Township of Winchester, Village of Chesterville, Village of Winchester, as at December 31, 1997.

165

Name of Municipality: Township of North Frontenac

Formerly Known As: Township of Barrie, Township of Clarendon, Township of Miller, Township of Palmerston, Township of North Canonto, Township of South Canonto, as at December 31, 1997.

166

Name of Municipality: Township of North Glengarry

Formerly Known As: Township of Kenyon, Township of Lochiel, Town of Alexandria, Village of Maxville, Police Village of Apple Hill, as at December 31, 1997.

167

Name of Municipality: Township of North Grenville

Formerly Known As: Township of Oxford-on-Rideau, Town of Kemptville, Township of South Gower, as at December 31, 1997.

168

Name of Municipality: Township of North Himsworth as at March 31, 1999.

Formerly Known As: Same.

169

Name of Municipality: Township of North Kawartha

Formerly Known As: Township of Burleigh and Anstruther, Township of Chandos, as at December 31, 1997.

170

Name of Municipality: Town of North Perth

Formerly Known As: Township of Wallace, Township of Elma, Town of Listowel, as at December 31, 1997.

171

Name of Municipality: Township of The North Shore as at March 31, 1999.

Formerly Known As: Same.

172

Name of Municipality: Township of North Stormont

Formerly Known As: Township of Finch, Township of Roxborough, Village of Finch, Police Village of Avonmore (in the Township of Roxborough), as at December 31, 1997.

173

Name of Municipality: Town of Northeastern Manitoulin and the Islands

Formerly Known As: Township of Howland, Town of Little Current, all islands not part of other municipalities on Manitoulin Island, as at December 31, 1997.

174

Name of Municipality: Township of O'Conner as at March 31, 1999.

Formerly Known As: Same.

175

Name of Municipality: Township of Oliver Paipoonge

Formerly Known As: Township of Oliver, Township of Paipoonge, as at December 31, 1997.

176

Name of Municipality: Township of Opatatika as at March 31, 1999.

Formerly Known As: Same.

177

Name of Municipality: Township of Oro-Medonte

Formerly Known As: Portions of the Township of Medonte, Township of Oro, Township of Orillia, Township of Tay, Township of Flos, Township of Vespra, as at December 31, 1993.

178

Name of Municipality: Township of Otonabee-South Monaghan

Formerly Known As: Township of Otonabee, Township of South Monaghan, as at December 1, 1999.

179

Name of Municipality: City of Owen Sound as at March 31, 1999.

Formerly Known As: Same.

180

Name of Municipality: Township of Papineau-Cameron as at March 31, 1999.

Formerly Known As: Same.

181

Name of Municipality: Township of Perry as at March 31, 1999.

Formerly Known As: Same.

182

Name of Municipality: Township of Pelee as at March 31, 1999.

Formerly Known As: Same.

183

Name of Municipality: Township of Perth East

Formerly Known As: Township of Mornington, Township of Ellice, Township of North Easthope, Township of South Easthope, Village of Milverton, as at December 31, 1997.

184

Name of Municipality: The Township of Perth South

Formerly Known As: Township of Downie, Township of Blanshard, as at December 31, 1997.

185

Name of Municipality: Town of Perth as at March 31, 1999.

Formerly Known As: Same.

186

Name of Municipality: Town of Petawawa

Formerly Known As: Village of Petawawa, Township of Petawawa, as at June 30, 1996.

187

Name of Municipality: Township of Pickle Lake as at March 31, 1999.

Formerly Known As: Same.

188

Name of Municipality: Town of Plympton-Wyoming

Formerly Known As: Township of Plympton, Village of Wyoming, as at December 31, 2000.

189

Name of Municipality: Municipality of Powassan

Formerly Known As: Town of Powassan, Township of Himsworth South, Town of Trout Creek, as at December 31, 2000.

190

Name of Municipality: County of Prince Edward

Formerly Known As: County of Prince Edward, Town of Picton, Village of Bloomfield, Village of Wellington, Township of Ameliasburgh, Township of Athol, Township of Hallowell, Township of Hillier, Township of North Marysburgh, Township of South Marysburgh, Township of Sophiasburgh, as at December 31, 1997.

191

Name of Municipality: Township of Puslinch as at March 31, 1999.

Formerly Known As: Same.

192

Name of Municipality: City of Quinte West

Formerly Known As: City of Trenton, Village of Frankford, Township of Sidney, Township of Murray, as at December 31, 1997.

193

Name of Municipality: Town of Rainy River as at March 31, 1999.

Formerly Known As: Same.

194

Name of Municipality: Township of Ramara

Formerly Known As: Township of Mara, Township of Rama , as at December 31, 1993.

195

Name of Municipality: Township of Red Rock as at March 31, 1999.

Formerly Known As: Same.

196

Name of Municipality: Township of Rideau Lakes

Formerly Known As: Village of Newboro, Township of Bastard and South Burgess,
Township of North Crosby, Township of South Crosby,
Township of South Elmsley, as at December 31, 1997.

197

Name of Municipality: Township of Ryerson as at March 31, 1999.

Formerly Known As: Same.

198

Name of Municipality: Township of Schreiber as at March 31, 1999.

Formerly Known As: Same.

199

Name of Municipality: Township of Seguin

Formerly Known As: Township of Humphrey, Township of Foley, Township of
Christie, geographic/unorganized Township of Monteith
(western portion), Village of Rosseau, as at December 31,
1997.

200

Name of Municipality: Township of Severn

Formerly Known As: Portions of Village of Coldwater, Township of Matchedash,
Township of Medonte, Township of Orillia, Township of Tay,
as at December 31, 1993.

201

Name of Municipality: Township of Shedden as at March 31, 1999.

Formerly Known As: Same.

202

Name of Municipality: Town of Shelburne as at March 31, 1999.

Formerly Known As: Same.

203

Name of Municipality: Township of Shuniah as at March 31, 1999.

Formerly Known As: Same.

204

Name of Municipality: Township of Sioux Narrows-Nestor Falls

Formerly Known As: Township of Sioux Narrows, all of the geographic/unorganized townships of Code, Devonshire, Godson, Manross, MacQuarrie, Phillips, Tweedsmuir, and Work, portions of the geographic/unorganized townships of LeMay, McKeekin in Kenora District, and the geographic/unorganized townships of Claxton, Croome, and Mathieu in the Rainy River District, as at December 31, 2000.

205

Name of Municipality: Separated Town of Smiths Falls as at March 31, 1999.

Formerly Known As: Same.

206

Name of Municipality: Town of Smooth Rock Falls as at March 31, 1999.

Formerly Known As: Same.

207

Name of Municipality: Township of South Algonquin

Formerly Known As: Township of Airy and geographic/unincorporated townships of Dickens, Lyell, Murchison and Sabine, as at May 31, 1997.

208

Name of Municipality: Town of South Bruce Peninsula

Formerly Known As: Township of Albemarle, Township of Amabel, Town of Wiarton, Village of Hepworth, as at December 31, 1998.

209

Name of Municipality: Township of South Frontenac

Formerly Known As:	Township of Bedford, Township of Loughborough, Township of Portland, Township of Storrington, as at December 31, 1997.	210
Name of Municipality:	Village of South River as at March 31, 1999.	
Formerly Known As:	Same.	211
Name of Municipality:	Municipality of Southwest Middlesex	
Formerly Known As:	Township of Ekfrid, Township of Mosa, Village of Glencoe, Village of Wardsville, as at December 31, 2000.	212
Name of Municipality:	Township of Southwold as at March 31, 1999.	
Formerly Known As:	Same.	213
Name of Municipality:	Township of Springwater	
Formerly Known As:	Portions of the former Village of Elmvale, Township of Flos, Township of Medonte, Township of Vespra, Town of Wasaga Beach, as at December 31, 1993.	214
Name of Municipality:	Municipality of St. Charles	
Formerly Known As:	Township of Casimir, Jennings & Appleby and the geographic/unorganized townships of Cherriman and Haddo, as at December 31, 1998.	215
Name of Municipality:	Township of St. Clair	
Formerly Known As:	Township of Sombra, Township of Moore, as at December 31, 2000.	

216

Name of Municipality: Township of Stirling-Rawdon

Formerly Known As: Village of Stirling, Township of Rawdon, as at December 31, 1997.

217

Name of Municipality: Township of Stone Mills

Formerly Known As: Township of Camden East, Township of Sheffield, Village of Newburgh, as at December 31, 1997.

218

Name of Municipality: Township of Strong as at March 31, 1996.

Formerly Known As: Same.

219

Name of Municipality: Township of Tay Valley

Formerly Known As: Township of South Sherbrooke, Township of Bathurst, Township of North Burgess, as at December 31, 1997.

220

Name of Municipality: Township of Tehkummah as at March 31, 1999.

Formerly Known As: Same.

221

Name of Municipality: Municipality of Temagami as at March 31, 1999.

Formerly Known As: Same.

222

Name of Municipality: Municipality of Thames Centre

Formerly Known As: Township of North Dorchester, Township of West Nissouri, Village of Dorchester, Police Village of Thorndale, as at December 31, 2000.

223

Name of Municipality: Town of Thessalon as at March 31, 1999.

Formerly Known As: Same.

224

Name of Municipality: Village of Thornloe as at March 31, 1999.

Formerly Known As: Same.

225

Name of Municipality: City of Thorold as at March 31, 1999.

Formerly Known As: Same.

226

Name of Municipality: City of Timmins as at March 31, 1999.

Formerly Known As: Same.

227

Name of Municipality: Township of Tiny as at March 31, 1999.

Formerly Known As: Same.

228

Name of Municipality: Municipality of Trent Hills

Formerly Known As: Municipality of Campbellford/Seymour, Township of Percy, Village of Hastings, Police Village of Warkworth (Jan 1998-Town of Campbellford, Township of Seymour amalgamated into the Municipality of Campbellford/Seymour), as at December 31, 2000.

229

Name of Municipality: Township of Tudor and Cashel as at March 31, 1999.

Formerly Known As: Same.

230

Name of Municipality: Municipality of Tweed

Formerly Known As: Village of Tweed, Township of Hungerford, Township of Elzevir and Gromsthorpe, as at December 31, 1997.

231

Name of Municipality: Township of Tyendinaga as at March 31, 1999.

Formerly Known As: Same.

232

Name of Municipality: Township of Val Rita-Harty as at March 31, 1999.

Formerly Known As: Same.

233

Name of Municipality: Township of Wainfleet as at March 31, 1999.

Formerly Known As: Same.

234

Name of Municipality: Municipality of West Elgin

Formerly Known As: Township of Aldborough, Village of West Lorne, Police Village of Rodney, as at December 31, 1997.

235

Name of Municipality: Town of Whitchurch-Stouffville as at March 31, 1999.

Formerly Known As: Village of Stouffville and portions of the Township of Whitchurch and the Township of Markham.

236

Name of Municipality: Township of White River as at March 31, 1999.

Formerly Known As: Same.

Name of Municipality:

Municipality of Whitestone

Formerly Known As:

Township Hagerman, and the geographic/unorganized townships of Ferrie, McKenzie, East Burpee, and a portion of the Township of Magnetawan, as at December 31, 1999.

Name of Municipality:

Township of Wollaston as at March 31, 1999.

Formerly Known As:

Same.

Tab 2 - FIRST NATION RESERVES

Reserve Name: Abitibi I.R. No. 70

Band Name: Wahgoshig First Nation

Reserve Name: Alderville I.R No. 37

Band Name: Alderville First Nation

Reserve Name: Aroland Indian Settlement

Band Name: Aroland

Reserve Name: Big Grassy River I.R. No. 35G

Band Name: Big Grassy First Nation

Reserve Name: Big Island Mainland 93

Band Name: Anishnaabeg of Naongashiing

Reserve Name: Cape Croker Island I.R. No. 27, Neyaashiinigmiing Reserve

Band Name: Chippewas of Nawash First Nation

Reserve Name: Chippewas of the Thames

Band Name: Chippewas of the Thames First Nation

Reserve Name: Chippewas of the Thames First Nation

Band Name: Chapleau Ojibway First Nation

10

Reserve Name: Christian Island I.R. No.30

Band Name: Beausoleil First Nation

11

Reserve Name: Cockburn Island 19, 19A

Band Name: Zhiibaahaasing First Nation

12

Reserve Name: Constance Lake I.R. 92

Band Name: Constance Lake First Nations

13

Reserve Name: Couchiching I.R. No. 16A

Band Name: Couchiching First Nation

14

Reserve Name: Curve Lake I.R. No. 35

Band Name: Curve Lake First Nation

15

Reserve Name: Dalles I.R. No. 38C

Band Name: Ochiichagwe'babigo'ining First Nation

16

Reserve Name: Duck Lake R.R. No. 76B

Band Name: Brunswick House First Nation

17

Reserve Name: Dokis I.R. No. 9

Band Name: Dokis First Nation

18

Reserve Name: Eagle Lake I.R. No. 27

Band Name: Eagle Lake First Nation

19

Reserve Name: English River I.R. No.21

Band Name: Grassy Narrows First Nation

20

Reserve Name: Factory Island I.R. No. 1

Band Name: Moose Factory First Nation

21

Reserve Name: Georgina Island I.R. No. 33

Band Name: Chippewas of Georgina Island First Nation

22

Reserve Name: Gibson I.R. No. 31 Wahta mohawk

Band Name: Mohawks of Gibson

23

Reserve Name: Golden Lake No. 39

Band Name: Algonquins Golden Lake First Nation

24

Reserve Name: Henvey Inlet I.R. No. 2 French River I.R. 13

Band Name: Henvey Inlet First Nation

25

Reserve Name: Hiawatha I.R. No.36

Band Name: Ojibways of Hiawatha First Nation

26

Reserve Name: Islington I.R No. 29

Band Name: Wabasemoong Independent Nations

27

Reserve Name: Kenora I.R. No. 38B

Band Name: Wauzhushk Onigum Nation

28

Reserve Name: Kettle Point I.R. No. 44

Band Name: Chippewas of Kettle and Stony Point First Nation

29

Reserve Name: Lac des Milles Lacs I.R. 22A1, Seine River I.R. 22A2

Band Name: Lac des Milles Lacs

30

Reserve Name: Lac Suel I.R. No. 28

Band Name: Lac Suel Nation

31

Reserve Name: Lake Helen I.R. No. 53A

Band Name: Red Rock Band

32

Reserve Name: Long Lake I.R. No. 77

Band Name: Ginoogaming First Nation

33

Reserve Name: Long Lake I.R. No. 58

Band Name: Long Lake No. 58 First Nation

34

Reserve Name: Magnetewan I.R No. 1

Band Name: Magnetewan First Nation

35

Reserve Name: Manitou Rapids I.R. No. 11

Band Name: Rainy River First Nation

36

Reserve Name: Matachewan I.R 72

Band Name: Matachewan First Nation

37

Reserve Name: Mattagami I.R No.71

Band Name: Mattagami First Nation

38

Reserve Name: Mississagi River I.R No.8

Band Name: Mississauga First Nation

39

Reserve Name: Moberg I.R No. 82

Band Name: Pic Moberg First Nation

40

Reserve Name: Moose Point I.R No. 79

Band Name: Moose Deer Point First Nation

41

Reserve Name: Moravian I.R. No. 47

Band Name: Delaware First Nation

42

Reserve Name: Muncey Delaware Nation No. 1

Band Name: Munsee-Delaware First Nation

43

Reserve Name: Neguaguon Lake I.R No. 25d

Band Name: Lac La Croix First Nation

44

Reserve Name: New Credit I.R 40A

Band Name: Mississaugas of the New Credit First Nation

45

Reserve Name: New Post 69, 69a

Band Name: New Post First Nation

46

Reserve Name: Nipissing I.R No. 10

Band Name: Nipissing First Nation

47

Reserve Name: Northwest Angle I.R No. 33B and Whitefish Bay I.R. No. 33a

Band Name: Northwest Angle No. 33 First Nation

48

Reserve Name: Oneida I.R No. 41

Band Name: ONA YO TE'A:KA

Reserve Name: Osnaburgh I.R No. 63A, 63B

Band Name: Osnaburgh First Nation

Reserve Name: Parry Island I.R No. 16

Band Name: Wasauksing First Nation

Reserve Name: Pays Plat I.R. No. 51

Band Name: Pays Plat First Nation

Reserve Name: Pic River I..R. No. 50

Band Name: Ojibways of Pic River No. 50 First Nation

Reserve Name: Rainy Lake I.R No. 17A, 17B

Band Name: Naicatchewenin First Nation

Reserve Name: Rainy Lake I.R. 26A

Band Name: Nicickousemenecaning First Nation

Reserve Name: Rainy Lake I.R. No. 18c

Band Name: Stanjikoming First Nation

Reserve Name: Rama I.R. No. 32

Band Name: Chippewas of Mnjikaning First Nation

57

Reserve Name: Rat Portage I.R No. 38A

Band Name: Washagamis Bay First Nation

58

Reserve Name: Rocky Bay I.R. No. 1

Band Name: Rocky Bay First Nation

59

Reserve Name: Sabaskong Bay 32c, Whitefish Bay 32a, Yellow Girl Bay 32b

Band Name: Naotkamegwanning Anishnabe First Nation

60

Reserve Name: Sabaskong Bay I.R 35D

Band Name: Ojibways of Onegaming First Nation

61

Reserve Name: Sarnia I.R.No.45

Band Name: Chippewas of Sarnia

62

Reserve Name: Saug-A-Gaw-Sing I.R. No. 1

Band Name: Big Island First Nation

63

Reserve Name: Saugeen I.R. No. 29

Band Name: Chippewas of Saugeen First Nation

64

Reserve Name: Savant Lake Indian Settlement

Band Name: Saugeen Nation

65

Reserve Name: Scugog I.R. No. 34

Band Name: Mississauga of Scugog First Nation

66

Reserve Name: Seine River I.R. No. 23A, 23B, Sturgeon Falls No. 23

Band Name: Seine River First Nation

67

Reserve Name: Serpent River I.R. No. 7

Band Name: Serpent River First Nation

68

Reserve Name: Shawanaga I.R. No. 17

Band Name: Shawanaga First Nation

69

Reserve Name: Sheguiandah I.R. No. 24

Band Name: Sheguiandah First Nation

70

Reserve Name: Sheshegwaning I.R. No. 20

Band Name: Sheshegwaning First Nation

71

Reserve Name: Shoal Lake I.R. No 39A

Band Name: Shoal Lake No. 39 First Nation

72

Reserve Name: Shoal Lake I.R. No 40

Band Name: Shoal Lake No. 40 First Nation

73

Reserve Name: Six Nations I.R. No. 40

Band Name: Six Nations of the Grand River Territory

74

Reserve Name: Slate Falls Indian Settlement

Band Name: Slate Falls Nation

75

Reserve Name: Spanish River I.R. No. 5

Band Name: Sagamok Anishnawbek

76

Reserve Name: Sucker Creek I.R NO. 23

Band Name: Sucker Creek First Nation

77

Reserve Name: Thessalon I.R. No. 12

Band Name: Thessalon First Nation

78

Reserve Name: Tyendinaga Mohawk Territory

Band Name: Mohawks of the Bay of Quinte

79

Reserve Name: Wabauskang 21

Band Name: Wabauskang First Nation

80

Reserve Name: Wabigoon Lake I.R No. 27

Band Name: Wabigoon Lake Ojibway Nation

81

Reserve Name: Wahnapiatae 11

Band Name: Wahnapiatae First Nation

82

Reserve Name: Walpole Island I.R. No.46

Band Name: Walpole Island First Nation

83

Reserve Name: West Bay I.R. No. 22

Band Name: West Bay First Nation

84

Reserve Name: Whitefish Bay I.R No. 32A

Band Name: Whitefish Bay First Nation

85

Reserve Name: Whitefish Bay I.R No. 34A and Lake of the Woods I.R No. 37

Band Name: Northwest Angle No. 37 First Nation

86

Reserve Name: Whitefish Lake I.R. No. 6

Band Name: Whitefish Lake First Nation

87

Reserve Name: Whitefish River I.R. No. 4

Band Name: Whitefish River First Nation

88

Reserve Name: Wikewemikong I.R. No. 26

Band Name: Wikwemikong Unceded First Nation

TAB 3 UNORGANIZED TOWNSHIPS

1

Networks provides service to numerous Unorganized geographic townships. These townships are not incorporated as municipalities.

2

Tab 4 - MUNICIPALITIES SERVICED BY NETWORKS AND OTHER LOCAL DISTRIBUTION COMPANIES

1

Name of Municipality: Township of Alfred and Plantagenet

Formerly Known As: Township of Alfred, Village of Alfred, Township of North Plantagenet, Village of Plantagenet, as at December 31, 1996.

Area Not Served By Networks: The area served by Hydro 2000 Inc. described as the former Villages of Alfred and Plantagenet as more particularly set out in Licence No. ED-2002-0542.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

2

3

Name of Municipality: Town of Amherstburg

Formerly Known As: Town of Amherstburg, Township of Anderdon, Township of Malden, as at December 31, 1997.

Area Not Served By Networks: The area served by Essex Powerlines Corporation described as the former Town of Amherstburg as more particularly set out in Licence No. ED-2002-0499.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: Two industrial (former Direct Class) customers located at 381 Front Road North, Amherstburg ON, and 99 Thomas Road, Amherstburg ON

4

Name of Municipality: Township of Asphodel-Norwood

Formerly Known As: Township of Asphodel, Village of Norwood, as at December 31, 1997.

Area Not Served By Networks: The area served by Asphodel/Norwood Distribution Inc. described as the former Village of Norwood as more particularly set out in Licence No. ED-2002-0506.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

5

Name of Municipality: Town of Aylmer as at January 1, 1998.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corporation described as the Town of Aylmer as more particularly set out in Licence No. ED-2002-0156.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

6

Name of Municipality: City of Belleville

Formerly Known As: City of Belleville, Township of Thurlow, City of Quinte West, as at December 31, 1997.

Area Not Served By Networks: The area served by Veridian Connections Inc. described as the former City of Belleville as more particularly set out in Licence No. ED-2002-0503.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

7

Name of Municipality: Town of the Blue Mountains

Formerly Known As: Town of Thornbury, Township of Collingwood, as at December 31, 1997.

Area Not Served By Networks: The area served by Collingwood Utility Services Corporation (COLLUS) described as the former Town of Thornbury as more particularly set out in Licence No. ED-2002-0518.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

8

Name of Municipality: Municipality of Bluewater

Formerly Known As: Township of Hay, Township of Stanley, Village of Bayfield, Village of Hensall, Village of Zurich, as at December 31, 2000.

Area Not Served By Networks: The area served by Festival Hydro Inc. described as the former Village of Hensall, and the former Village of Zurich as more particularly set out in Licence No. ED-2002-0513.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

9

Name of Municipality: Town of Bracebridge

Formerly Known As: Townships of Macaulay, Draper, Monck, Oakely, Town of Bracebridge, as at December 31, 1970.

Area Not Served By Networks: The area served by Lakeland Power Distribution Ltd. described as the former Town of Bracebridge, as more particularly set out in Licence No. ED-2002-0540.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: One industrial customer located at 154 Beaumont Drive, Bracebridge, ON.

10

Name of Municipality: Town of Bradford-West Gwillimbury

Formerly Known As: Town of Bradford, Township of West Gwillimbury, as at December 31, 1990.

Area Not Served By Networks: The area served by Barrie Hydro Distribution Inc. described as the former Town of Bradford as more particularly set out in Licence No. ED-2002-0534.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

11

Name of Municipality: County of Brant (Initially known as City of Brant-on-the-Grand)

Formerly Known As: County of Brant, Town of Paris, Township of Brantford, Township of Burford, Township of Oakland, Township of Onondaga, Township of South Dumfries, as at December 31, 1998.

Area Not Served By Networks: The area served by Brant County Power Inc. described as the former Village of Burford, the former Town of Paris, the former Township of Brantford and the former Police Village of St. George (in the former Township of South Dumfries) as more particularly set out in Licence No. ED-2002-0522.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

12

Name of Municipality: Township of Brock

Formerly Known As: Village of Beaverton, Village of Cannington, Township of Brock, Township of Thorah, as at December 31, 1973.

Area Not Served By Networks: The area served by Veridian Connections Inc. described as the former Villages of Beaverton and Cannington and the former Police Village of Sunderland (in the former Township of Brock) as more particularly set out in Licence No. ED-2002-0503.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

13

Name of Municipality: Municipality of Brockton

Formerly Known As: Township of Greenock, Township of Brant, Town of Walkerton, as at December 31, 1998.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Town of Walkerton and the portion of the former Police Village of Elmwood (in the former Township of Brant) as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

14

Name of Municipality: Township of Brooke-Alvinston

Formerly Known As: Township of Brooke, Village of Alvinston

Area Not Served By Networks: The area served by Bluewater Power Distribution Corp. described as the former Village of Alvinston as more particularly set out in Licence No. ED-2002-0517.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

15

Name of Municipality: Municipality of Central Elgin

Formerly Known As: Township of Yarmouth, Village of Belmont, Village of Port Stanley, as at December 31, 1997.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corporation described as the former Villages of Belmont and Port Stanley as more particularly set out in Licence No. ED-2002-0516.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

16

Name of Municipality: Municipality of Central Huron

Formerly Known As: Township of Goderich, Township of Hullett, Town of Clinton, as at December 31, 2000.

Area Not Served By Networks: The area served by Clinton Power Corporation described as the former Town of Clinton as more particularly set out in Licence No. ED-20025-2000.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

17

Name of Municipality: Township of Centre Wellington

Formerly Known As: Town of Fergus, Village of Elora, Township of West Garafraxa, Township of Nichol, Township of Pilkington, as at December 31, 1998.

Area Not Served By Networks: The area served by Centre Wellington Hydro Ltd. described as the former Town of Fergus and the former Village of Elora as more particularly set out in Licence No. ED-2002-0498.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

18

Name of Municipality: Municipality of Chatham-Kent

Formerly Known As: City of Chatham, County of Kent, Town of Blenheim, Town of Bothwell, Town of Dresden, Town of Ridgeway, Town of Tilbury, Town of Wallaceburg, Village of Erie Beach, Village of Erieau, Village of Highgate, Village of Thamesville, Village of Wheatley, Township of Camden, Township of Chatham, Township of Dover, Township of Harwich, Township of Howard, Township of Orford, Township of Raleigh, Township of Rodney, Township of Tilbury East, Township of Zone, as at December 31, 1997.

Area Not Served By Networks: The area served by Chatham-Kent Hydro Inc. described as the former City of Chatham, former Police Village of Merlin (straddling the former townships of Raleigh and Tilbury East), former Village of Erieau, former Village of Thamesville, former Town of Bothwell, former Village of Wheatley, former Town of Dresden, former Town of Blenheim, former Town of Tilbury, former Town of Ridgeway, and the former Town of Wallaceburg as more particularly set out in Licence No. ED-2002-0563.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

19

Name of Municipality: Municipality of Clarington

Formerly Known As: Town of Bowmanville, Village of Newcastle, Township of Clarke, Township of Darlington, as at December 31, 1973.

Area Not Served By Networks: The area served by Veridian Connections Inc. described as the former Town of Bowmanville, the former Police Village of Orono (in the former Township of Clarke), the former Town of Newcastle as more particularly set out in Licence No. ED-2002-0503.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: 1 Industrial customer located at 410 Wavely Road, Bowmanville ON.

20

Name of Municipality: Township of Clearview

Formerly Known As: Town of Stayner, Village of Creemore, Township of Nottawasaga, Township of Sunnidale, as at December 31, 1993.

Area Not Served By Networks: The area served by Collingwood Utility Services Corp. described as the former Town of Stayner and the former Village of Creemore as more particularly set out in Licence No. ED-2002-0518.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

21

Name of Municipality: Town of Cochrane

Formerly Known As: Town of Cochrane, Township of Glackmeyer, Unorganized Twp. of Lamarche, as at December 31, 1999.

Area Not Served By Networks: The area served by Northern Ontario Wires Inc. described as the former Town of Cochrane as more particularly set out in Licence No. ED-2002-0018.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

22

Name of Municipality: Township of Cramahe

Formerly Known As: Village of Colborne, Township of Cramahe, as at December 31, 2000.

Area Not Served By Networks: The area served by Lakefront Utilities Inc. described as the former Village of Colborne as more particularly set out in Licence No. ED-2002-0545.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

23

Name of Municipality: Municipality of Dutton/Dunwich

Formerly Known As: Township of Dunwich, Village of Dutton, as at December 31, 1997.

Area Not Served By Networks: The area served by Dutton Hydro Ltd. described as the former Village of Dutton as more particularly set out in Licence No. ED-2003-0025.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

24

Name of Municipality: Town of East Gwillimbury as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Newmarket Hydro Ltd. as particularly set out in Licence No. ED- 2002-0553.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

25

Name of Municipality: Township of East Luther Grand Valley

Formerly Known As: Township of East Luther, Village of Grand Valley, as at December 31, 1994.

Area Not Served By Networks: The area served by Grand Valley Energy Inc. described as the former Village of Grand Valley as more particularly set out in Licence No. ED-2002-0512.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

26

Name of Municipality: The Township of East Zorra-Tavistock

Formerly Known As: Township of East Zorra, Town of Tavistock, as at December 31, 1997.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corp. described as the former Town of Tavistock as more particularly set out in Licence No. ED-2002-0516.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

27

Name of Municipality: Township of Edwardsburgh/Cardinal

Formerly Known As: Village of Cardinal, Township of Edwardsburgh, as at December 31, 2000.

Area Not Served By Networks: The area served by Rideau St. Lawrence Distribution Inc. described as the former Village of Cardinal as more particularly set out in Licence No. ED-2003-0003.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

28

Name of Municipality: Township of Essa as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Barrie Hydro Distribution Inc. described as the former Police Village of Thorton as more particularly set out in Licence No. ED-2002-0534.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

29

Name of Municipality: Town of Essex

Formerly Known As: Town of Essex, Town of Harrow, Township of North Colchester, Township of South Colchester, as at December 31, 1998.

Area Not Served By Networks: The area served by E.L.K. Energy Inc. described as the former Town of Essex and the former Town of Harrow as more particularly set out in Licence No. ED-2003-0015.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

30

Name of Municipality: Township of Frontenac Islands

Formerly Known As: Township of Howe Island, Township of Wolfe Island as at December 31, 1977.

Area Not Served By Networks: The area served by Canadian Niagara Power Inc. described as part of the former Township of Howe Island as more particularly set out in Licence No. ED-2002-0572

Networks assets within area not served by Networks: No

Customer(s) within area not served by Networks: No

Name of Municipality: Town of Gravenhurst

Formerly Known As: Formerly the Township of Morrison, the United Townships of Medora and Wood, the Township of Muskoka, the Township of Ryde, the Town of Gravenhurst, as at December 31, 1970.

Area Not Served By Networks: The area served by Gravenhurst Hydro Electric Inc. described as the former urban boundary of the Town of Gravenhurst as more particularly set out in Licence No. ED-2002-0576.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: City of Greater Sudbury

Formerly Known As: Region of Sudbury, City of Sudbury, City of Valley East, Town of Capreol, Town of Nickel Centre, Town of Onaping Falls, Town of Rayside-Balfour, Town of Walden, as at December 31, 2000.

Area Not Served By Networks: The area served by Greater Sudbury Hydro Inc. described as the former City of Sudbury, the former townsites of the former Town of Capreol, and the former Town of Conniston (part of former Town of Nickel Centre) as more particularly set out in Licence No. ED-2002-0559.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Guelph/Eramosa

Formerly Known As: Township of Guelph, Township of Eramosa, as at December 31, 1998.

Area Not Served By Networks: The area served by Wellington Electric Distribution Inc. described as the former Police Village of Rockwood (in the former Township of Eramosa) as more particularly set out in Licence No. ED-2002-0564.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

34

Name of Municipality: City of Hamilton

Formerly Known As: Region of Hamilton-Wentworth, City of Hamilton, City of Stoney Creek, Town of Ancaster, Town of Dundas, Town of Flamborough, Township of Glanbrook, as at December 31, 2000.

Area Not Served By Networks: The area served by Hamilton Hydro Inc. described as the former City of Hamilton, the former Police Village of Ancaster, former Town of Dundas, the former Police Village of Lynden (straddling the former Town of Flamborough and Town of Ancaster), the former Village of Waterdown, and the former City of Stoney Creek as more particularly set out in Licence No. ED-2002-0566.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

35

Name of Municipality: Town of Hawkesbury as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Hydro Hawkesbury Inc. described as the Town of Hawkesbury prior to annexation or amalgamation pursuant to the Minister's Order or Restructuring Act as more particularly set out in Licence No. ED-2003-0027.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

36

Name of Municipality: Municipality of Huron Shores

Formerly Known As: Township of Day and Bright Add'l, Township of Thessalon, Village of Iron Bridge, as at December 31, 1998.

Area Not Served By Networks: The area served by Great Lakes Power Limited described as part of the former Township of Thessalon or as more particularly set out in Licence No. ED-1999-0227.

Networks assets within area not served by Networks: No

Customer(s) within area not served by Networks: No

37

Name of Municipality: Town of Huntsville

Formerly Known As: Township of Brunel, Village of Port Sydney, Town of Chaffey, Township of Stephenson, Township of Stisted, Town of Huntsville, as at December 31, 1970.

Area Not Served By Networks: The area served by Lakeland Power Distribution Ltd. described as the former Town of Huntsville as more particularly set out in Licence No. ED-2002-0540.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: One Industrial customer located at 61 Domtar Road, Huntsville ON.

38

Name of Municipality: Municipality of Huron East

Formerly Known As: Village of Brussels, Township of Grey, Township of McKillop, Town of Seaforth, Township of Tuckersmith, as at December 31, 2000.

Area Not Served By Networks: The area served by Festival Hydro Inc. described as the former Village of Brussels and the former Town of Seaforth as more particularly set out in Licence No. ED-2002-0513.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

39

Name of Municipality: Township of Huron-Kinloss

Formerly Known As: Township of Huron (former Police Village of Ripley amalgamated with twp in 1995), Township of Kinloss, Village of Lucknow, as at December 31, 1998.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Police Village of Ripley (in the former Township of Huron) and the former Village of Lucknow as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

40

Name of Municipality: Town of Ingersoll

Formerly Known As: Same.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corporation described as the Town of Ingersoll as more particularly set out in Licence No. ED-2002-0516.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

41

Name of Municipality: Town of Iroquois Falls as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Northern Ontario Wires Inc. described as the Town of Iroquois Falls as more particularly set out in Licence No. ED-2002-0018.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

42

Name of Municipality: City of Kenora

Formerly Known As: Town of Kenora, Town of Keewatin, Town of Jaffray Melick, as at December 31, 1999.

Area Not Served By Networks: The area served by Kenora Hydro Electric Distribution Inc. described as the former Town of Kenora and part of the former Town of Keewatin as more particularly set out in Licence No. ED-2003-0030.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

43

Name of Municipality: Township of Killaloe, Hagarty and Richards

Formerly Known As: Township of Hagarty and Richards, Village of Killaloe, as at June 30, 1999.

Area Not Served By Networks: The area served by Ottawa River Power Corp. described as the former Village of Killaloe as more particularly set out in Licence No. ED-2002-0033.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

44

Name of Municipality: Municipality of Kincardine

Formerly Known As: Town of Kincardine, Township of Bruce (Village of Tiverton, Township of Bruce amalgamation), Township of Kincardine, as at December 31, 1998.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Town of Kincardine as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

45

Name of Municipality: City of Kingston

Formerly Known As: City of Kingston, Township of Kingston, Township of Pittsburgh, as at December 31, December 31, 1997.

Area Not Served By Networks: The area served by Kingston Electricity Distribution Ltd. described as the former City of Kingston, the former Township of Kingston, and part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2003-0057.

The area served by Canadian Niagara Power Inc. described as part of the former Township of Pittsburgh as more particularly set out in Licence No. ED-2002-0572.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

46

Name of Municipality: Town of Kingsville

Formerly Known As: Town of Kingsville, Township of Gosfield North, Township of Gosfield South, as at December 31, 1997.

Area Not Served By Networks: The area served by E.L.K. Energy Inc. described as the former Town of Kingsville and the former Police Village of Cottam (in the former Township of Gosfield North) as more particularly set out in Licence No. ED-2003-0015.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

47

Name of Municipality: Town of Lakeshore

Formerly Known As: Township of Lakeshore, (Jan 1998: Town of Belle River, Township of Maidstone amalgamated into Lakeshore Township), Township of Rochester, Township of Tillbury North, Township of Tillbury West, as at December 31, 1998.

Area Not Served By Networks: The area served by E.L.K. Energy Inc. described as the former Police Village of Comber (in the former Township of Tillbury West) and the former Town of Belle River as more particularly set out in Licence No. ED-2003-0015.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Municipality of Leamington

Formerly Known As: Town of Leamington, Township of Mersea, as at December 31, 1998.

Area Not Served By Networks: The area served by Essex Powerlines Ltd. described as the former Town of Leamington as more particularly set out in Licence No. ED-2002-0499.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Leeds and the Thousand Islands

Formerly Known As: Township of Front of Leeds and Lansdowne, Township of Rear of Leeds and Lansdowne, Township of Front of Escott, as at December 31, 2000.

Area Not Served By Networks: The area served by Canadian Niagara Power Inc. described as part of the former Township of the Front of Leeds and Lansdowne as more particularly set out in Licence No. ED-2002-0572.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Municipality of Magnetawan

Formerly Known As: Township of Chapman, Village of Magnetawan, Unorganized Township of Croft, as at December 31, 1997.

Area Not Served By Networks: The area served by Lakeland Power Distribution Ltd. described as the former Village of Magnetawan as more particularly set out in Licence No. ED-2002-0540.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Town of Minto

Formerly Known As: Township of Minto, Town of Palmerston, Town of Harriston, Village of Clifford, Township of Minto, as at December 31, 1998.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Town of Harriston, the former Town of Palmerston, and the former Village of Clifford as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: The Corporation of the Town of Mississippi Mills

Formerly Known As: Town of Almonte, Township of Pakenham, Township of Ramsay, as at December 31, 1998.

Area Not Served By Networks: The area served by Ottawa River Power Corp. described as the former Town of Almonte as more particularly set out in Licence No. ED-2003-0033.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Town of New Tecumseth

Formerly Known As: Town of Alliston, the Village of Beeton, the Village of Tottenham and the portion of the Township of Tecumseth, as at December 31, 1991.

Area Not Served By Networks: The area served by Barrie Hydro Distribution Inc. described as the former Town of Alliston, the former Village of Beeton and the former Village of Tottenham (all in the former Township of Tecumseth) as more particularly set out in Licence No. ED-2002-0534.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: 1 Industrial customer located in the former Town of Alliston.

54

Name of Municipality: The Corporation of Norfolk County

Formerly Known As: Township of Norfolk, Township of Delhi, Town of Simcoe, City of Nanticoke (westerly 'half' only), as at December 31, 2000.

Area Not Served By Networks: The area served by Norfolk Power Distribution Co. Ltd. described as the former Town of Delhi (in the former Township of Delhi), the westerly half of the former City of Nanticoke, the former Village of Port Rowan (in former Township of Norfolk), and the former Town of Simcoe as more particularly set out in Licence No. ED-2002-0521.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: 1 Industrial customer located at Lake Erie and Regional Rd.. 3, Nanticoke, ON.

55

Name of Municipality: Township of North Huron

Formerly Known As: Town of Wingham, Village of Blyth, Township of East Wawnosh, as at December 31, 2000.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Town of Wingham as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: 2 Industrial customers located at 40621 Amberly Rd., and 200 Water Street Wingham, ON.

56

Name of Municipality: Municipality of North Middlesex

Formerly Known As: Township of McGillivray, Township of East Williams, Township of West Williams, Town of Parkhill, Village of Ailsa Craig, as at December 31, 2000.

Area Not Served By Networks: The area served by Middlesex Power Distribution Corp. described as the former Town of Parkhill as more particularly set out in Licence No. ED-2003-0059.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

57

Name of Municipality: The Township of Norwich as at March 31, 1999

Formerly Known As: Township of North Norwich, Township of South Norwich, Township of East Oxford, Village of Norwich, Village of Burgessville, and Police Village of Otterville.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corp. described as the former Village of Norwich, the former Village of Burgessville, and the former Police Village of Otterville as more particularly set out in Licence No. ED-2002-0516.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

58

Name of Municipality: City of Ottawa

Formerly Known As: Region of Ottawa-Carleton, City of Gloucester, City of Kanata, City of Nepean, City of Ottawa, City of Vanier, Township of Cumberland, Township of Goulbourn, Township of Osgoode, Township of Rideau, Township of West Carleton, Village of Rockcliffe Park, as at December 31, 2000.

Area Not Served By Networks: The area served by Hydro Ottawa Limited. described as the former City of Gloucester, the former City of Kanata, the former City of Nepean, the former City of Ottawa, the former City of Vanier, the former Township of Goulbourn, the former Village of Rockcliffe Park, and the portion of the former Township of Rideau on Long Island, North of Bridge Street, as more particularly set out in Licence No. ED-2002-0556.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Town of Pelham

Formerly Known As: Township of Pelham, Village of Fonthill, as at December 31, 1969.

Area Not Served By Networks: The area served by Peninsula West Utilities Ltd. described as the former Village of Fonthill as more particularly set out in Licence No. ED-2002-0555.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: City of Peterborough as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Peterborough Distribution Inc. described as the City of Peterborough as more particularly set out in Licence No. ED-2002-0504.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Municipality of Port Hope

Formerly Known As: Town of Port Hope, Township of Hope (initially restructured as Municipality of Port Hope and Hope), as at December 31, 2000.

Area Not Served By Networks: The area served by Veridian Connections Inc. described as the former Town of Port Hope as more particularly set out in Licence No. ED-2002-0503.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Municipality of Red Lake

Formerly Known As: Township of Red Lake, Township of Golden, as at June 30, 1997.

Area Not Served By Networks: The area served by Gold Corp Inc. described as part of the former Improvement District of Balmertown.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Russell as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Cooperative Hydro Embrun Inc. described as the former Police Village of Embrun as more particularly set out in Licence No. ED-2002-0493.

Networks assets within area not served by Networks: No

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Sables-Spanish Rivers

Formerly Known As: Town of Massey, Town of Webbwood, Town of Spanish River, as at June 30, 1997.

Area Not Served By Networks: The area served by Espanola Regional Hydro Distribution Corp. described as the former Town of Massey and the former Town of Webbwood as more particularly set out in Licence No. ED-2002-0502.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Saugeen Shores

Formerly Known As: Town of Saugeen, Town of Southampton, Town of Port Elgin, as at December 31, 1998.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Town of Southampton and the former Town of Port Elgin as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

66

Name of Municipality: City of St. Thomas as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by St. Thomas Energy Inc. described as the City of St. Thomas as more particularly set out in Licence No. ED-2002-0523.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: 1 Industrial customer located at 1 Cosma Court

67

Name of Municipality: Township of Scugog

Formerly Known As: Township of Scugog, Township of Cartwright, Township of Reach, Village of Port Perry, as at December 31, 1973.

Area Not Served By Networks: The area served by Scugog Hydro Electric Corp. described as the former Village of Port Perry as more particularly set out in Licence No. ED-2002-0570.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

68

Name of Municipality: Municipality of Sioux Lookout as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Sioux Lookout Hydro Inc. described as the Municipality of Sioux Lookout as more particularly set out in Licence No. ED-2002-0514.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

69

Name of Municipality: Township of Smith-Ennismore-Lakefield

Formerly Known As: Village of Lakefield, Township of Smith-Ennismore (formerly Township of Smith and Township of Ennismore), as at December 31, 2000.

Area Not Served By Networks: The area served by Lakefield Distribution Inc. described as the former Village of Lakefield as more particularly set out in Licence No. ED-2002-0505.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

70

Name of Municipality: Municipality of South Bruce

Formerly Known As: Township of Mildmay-Carrick, Township of Teeswater-Culross, (Jan 1998: Village of Teeswater, Township of Culross amalgamated into the Township of Teeswater-Culross. Village of Mildmay, Township of Carrick amalgamated into the Township of Mildmay-Carrick), as at December 31, 1997.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Village of Mildmay and the former Village of Teeswater as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

71

Name of Municipality: Township of South Dundas

Formerly Known As: Township of Matilda, Township of Williamsburg, Village of Iroquois, Village of Morrisburg, as at December 31, 1997.

Area Not Served By Networks: The area served by Rideau St. Lawrence Distribution Ltd. described as the former Police Village of Williamsburg, the former Village of Morrisburg, and the former Village of Iroquois as more particularly set out in Licence No. ED-2003-0003.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

72

Name of Municipality: Township of South Glengarry

Formerly Known As: Township of Charlottenburgh, Township of Lancaster, Village of Lancaster, Police Village of Martintown, as at December 31, 1997.

Area Not Served By Networks: The area served by the Cornwall Street Railway Light and Power Company Ltd. described as part of the former Township of Charlottenburgh as more particularly set out in Licence No. ED-1999-0273.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

73

Name of Municipality: Municipality of South Huron

Formerly Known As: Township of Stephen, Township of Usborne, Town of Exeter, as at December 31, 2000.

Area Not Served By Networks: The area served by Festival Hydro Inc. described as the former Police Village of Dashwood as more particularly set out in Licence No. ED-2002-0513.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of South Stormont

Formerly Known As: Township of Osnabruck, Township of Cornwall, as at December 31, 1997.

Area Not Served By Networks: The area served by Cornwall Street Railway Light and Power Company Ltd. described as part of the former Township of Cornwall and part of the former Township of Osnabruk as more particularly set out in Licence No. ED-1999-0273.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Southgate

Formerly Known As: Village of Dundalk, Township of Egremont, Township of Proton, Police Village of Holstein, as at December 31, 1999.

Area Not Served By Networks: The area served by Wellington North Power Inc. described as the former Police Village of Holstein as more particularly set out in Licence No. ED-2002-0511.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: The Township of South-West Oxford

Formerly Known As: Township of West Oxford, Township of Dereham, Village of Beachville, as at December 31,. 1974.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corp. described as the former Village of Beachville as more particularly set out in Licence No. ED-2002-0516.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Strathroy-Caradoc

Formerly Known As: Town of Strathroy, Township of Caradoc, as at December 31, 2000.

Area Not Served By Networks: The area served by Middlesex Power Distribution Corp. described as the former Police Village of Mount Brydges (in the former Township of Caradoc) and the former Town of Strathroy as more particularly set out in Licence No. ED-2003-0059.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Township of Tay

Formerly Known As: Village of Port McNicoll, Village of Victoria Harbour, the Township of Medonte, Township of Tay, Township of Tiny, Township of Flos, Police Village of Waubesaushene, as at December 31, 1996.

Area Not Served By Networks: The area served by Tay Hydro Electric Distribution Company Inc. described as the former Village of Port McNicoll, the former Village of Victoria Harbour, the former Police Village of Waubesaushene and part of the former Township of Tay as more particularly set out in Licence No. ED-2002-0519.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

Name of Municipality: Town of Tecumseh

Formerly Known As: Town of Tecumseh, Village of St. Clair Beach, Township of Sandwich South, as at December 31, 1998.

Area Not Served By Networks: The area served by Essex Powerlines Corporation described as the former Town of Tecumseh and the former Village of St. Clair Beach as more particularly set out in Licence No. ED-2002-0499.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

80

Name of Municipality: Township of Terrace Bay as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Terrace Bay Superior Wires Inc. described as part of the Township of Terrace Bay as more particularly set out in Licence No. ED-2002-0543.

Networks assets within area not served by Networks: No

Customer(s) within area not served by Networks: No

81

Name of Municipality: Township of Uxbridge

Formerly Known As: Town of Uxbridge, Township of Scott, Township of Uxbridge, as at December 31, 1973.

Area Not Served By Networks: The area served by Veridian Connections Inc. described as the former Town of Uxbridge as more particularly set out in Licence No. ED-2002-0503.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

82

Name of Municipality: Town of Warwick

Formerly Known As: Village of Watford, Township of Warwick, as at December 31, 1997.

Area Not Served By Networks: The area served by Bluewater Power Distribution Corp. described as the former Village of Watford as more particularly set out in Licence No. ED-2002-0517.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

83

Name of Municipality: Township of Wellington North

Formerly Known As: Town of Mount Forest, Village of Arthur, Township of Arthur, Township of West Luther, as at December 31, 1998.

Area Not Served By Networks: The area served by Wellington North Power Inc. described as the former Village of Arthur and the former Town of Mount Forest as more particularly set out in Licence No. ED-2002-0511.

Networks assets within area not served by Networks: No

Customer(s) within area not served by Networks: No

84

Name of Municipality: Township of West Grey

Formerly Known As: Township of West Grey, Town of Durham (Jan 2000 Township Bentinck, Township of Glenelg, Town Normanby, Village of Neustadt amalgamated into the Township of West Grey), as at December 31, 1999.

Area Not Served By Networks: The area served by Westario Power Inc. described as the former Village of Neustadt and a portion of the former Police Village of Elmwood (in the former Township of Bentinck) as more particularly set out in Licence No. ED-2002-0515.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

85

Name of Municipality: Municipality of West Nipissing

Formerly Known As: Town of Cache Bay, Town of Sturgeon Falls, Township of Caldwell, Township of Field, Township of Springer, as at December 31, 1998.

Area Not Served By Networks: The area served by West Nipissing Energy Services Ltd. described as the former Town of Cache Bay and the former Town of Sturgeon Falls as more particularly set out in Licence No. ED-2002-0562.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

86

Name of Municipality: Municipality of West Perth

Formerly Known As: Township of Logan, Township of Fullarton, Town of Mitchell, Police Village of Dublin, as at December 31, 1997.

Area Not Served By Networks: The area served by West Perth Power Inc. described as the former Town of Mitchell and the former Police Village of Dublin as more particularly set out in Licence No. ED-2002-0508.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

87

Name of Municipality: Township of Whitewater Region

Formerly Known As: Township of Ross, Township of Westmeath, Village of Beachburg, Village of Cobden, as at December 31, 2000.

Area Not Served By Networks: The area served by Ottawa River Power Distribution Corp. described as the former Village of Beachburg as more particularly set out in Licence No. ED-2003-0033.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

88

Name of Municipality: City of Woodstock as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Woodstock Hydro Services Inc. described as the City of Woodstock as more particularly set out in Licence No. ED-2003-0011.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

89

Name of Municipality: Township of Zorra

Formerly Known As: Township of West Zorra, Township of East Nissouri, Township of North Oxford, Village of Embro, Village of Thamesford , as at December 31, 1997.

Area Not Served By Networks: The area served by Erie Thames Powerlines Corp. described as the former Village of Embro and the former Village of Thamesford as more particularly set out in Licence No. ED-2002-0516.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

90

Name of Municipality: Town of East Gwillimbury as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Newmarket Hydro Ltd. described as part of the south side of Green Lane as more particularly set out in Licence No. ED-2002-0553.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

91

Name of Municipality: The Town of Penetanguishene as at March 31, 1999.

Formerly Known As: Same.

Area Not Served By Networks: The area served by Barrie described as part of the Town of Penetanguishene as more particularly set out in Licence No. ED-2002-0534.

Networks assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: No

**Tab 5 - MUNICIPALITIES NOT SERVICED BY NETWORKS BUT WHERE
NETWORKS' ASSETS AND CUSTOMERS EXIST**

1

2

Name of Municipality: City of Cornwall

Assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: The customers located at 800 Second Street West and 501 Wallrich Avenue.

3

Name of Municipality: County of Haldimand

Assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: I customer located in Caledonia, Ontario.

4

Name of Municipality: City of Niagara Falls

Assets within area not served by Networks: Yes

Customer(s) within area not served by Networks: Three customers located at 8001 Daly Street, 7780 Stanley Ave, 6225 Progress Street.

SECTION - 1.3.2

Map of Hydro One Networks Distribution Service Territory

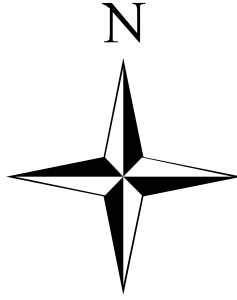
Electric Distribution Territory

- Legend:**
- Private/Non-Municipal LDCs
 - Municipal LDCs
 - Hydro One

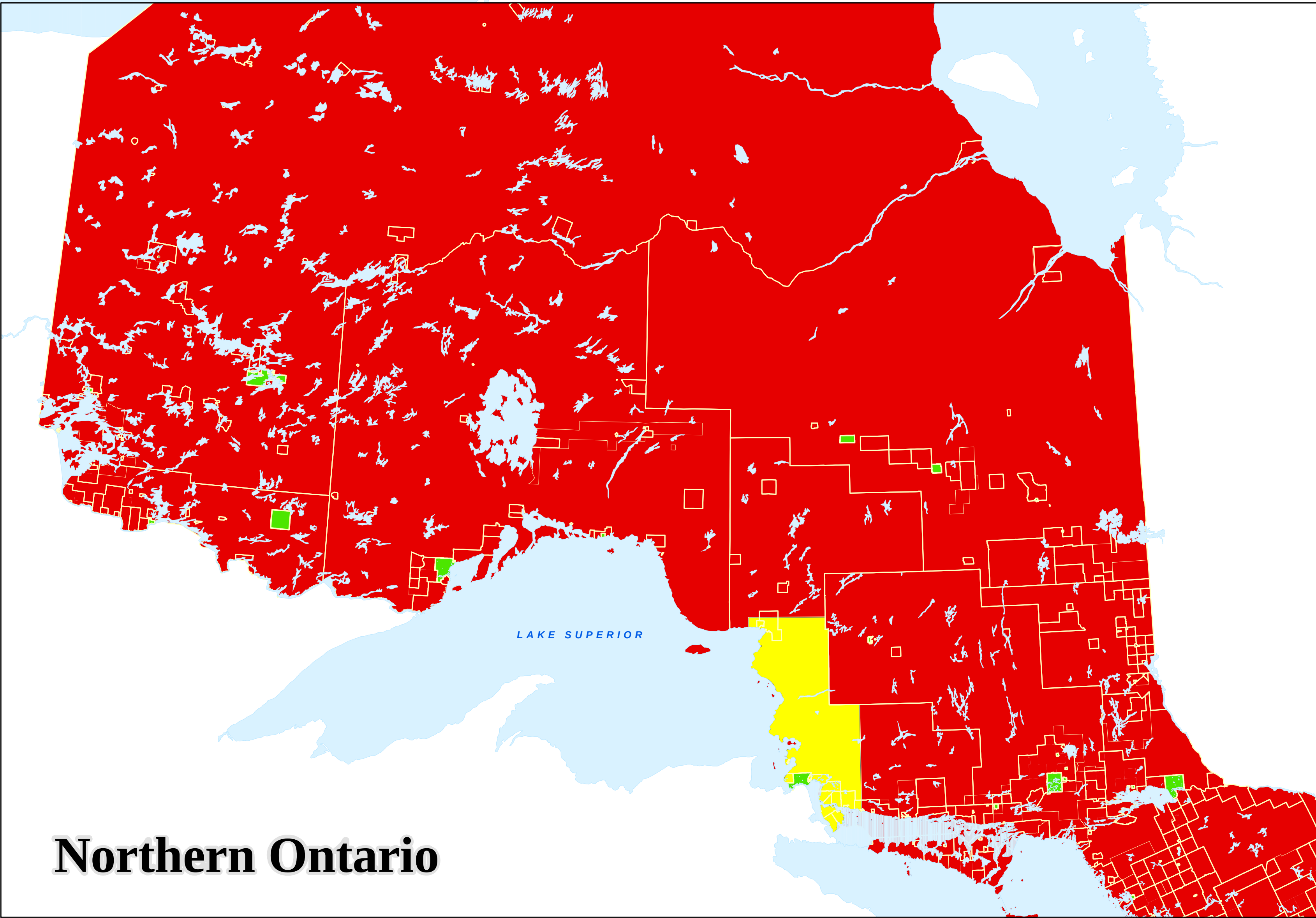


MAP PRODUCED BY GIS SERVICES
Inergi LP
Contact: (416) 345-5546 
Map 05-0043_rev_OEB
Date: April 2005

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0 200 400 800 Kilometers
1:700,000



SECTION - 1.3.3

**Hydro One Networks Inc.
Number of Customers by Rate Class - 2006**

Hydro One Networks Inc.

Number of Customers by Rate Class – 2006 (Excludes Hydro One Brampton and Hydro One Remotes)

Rate Class	Count	Subtotals by Main Class	Subtotal
U2	83895		
R1	308549		
R2	275218		
Acquired Residential	143693	Year Round Residential	811355
R3	71034		
R4	83724	Seasonal Residential	154758
F1	89087		
F3	1218	Farm	90305
UG2	6370		
G1	63551	Lights	5738
G3	15176		
T	365		
Acquired General Service	21998		
Directs	48	General Service & Directs	107508
LDCs – (represents delivery points to LDCs, NOT number of LDCs)	389	LDCs	389
Sentinel Lights (represents accounts with sentinel light tariff only - separately metered)	908		na
Streetlights - (represents accounts, NOT number of streetlights)	4830		Na
TOTALS	1170053	TOTALS	1170053

SECTION - 1.3.3

**Terrace Bay Superior Wires Inc.
Number of Customers by Rate Class**

Terrace Bay Superior Wires Inc.

Number of Customers by Rate Class

Rate Class	Count
Residential	833
General <50kw	97
General >50kw	11
Street Lights	1

SECTION - 1.4.3

**Terrace Bay Superior Wires Inc.
Financial Statements – 2005 and 2006**

31
Terrace Bay Superior Wires Inc.
Financial Statements
December 31, 2005

Grant Thornton 

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Statement of Operations and Retained Earnings	4
Statement of Cash Flows	5
Notes to the Financial Statements	6 - 13

Grant Thornton LLP
Chartered Accountants
Management Consultants

Auditors' Report

To the Shareholder of
Terrace Bay Superior Wires Inc.

We have audited the balance sheet of **Terrace Bay Superior Wires Inc.** as at December 31, 2005 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our 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 Corporation as at December 31, 2005 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Thunder Bay, Canada
February 16, 2006

Chartered Accountants

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ThunderBay@GrantThornton.ca
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Terrace Bay Superior Wires Inc.

Balance Sheet

December 31	2005	2004
	\$	\$
ASSETS		
Current		
Cash and cash equivalents	438,969	204,716
Accounts receivable	130,282	184,559
Unbilled revenue	187,843	170,926
Prepaid expenses	1,663	7,951
Total current assets	758,757	568,152
Long-term		
Regulatory assets	230,969	140,389
Organization costs <i>[note 3]</i>	—	1,333
Total long-term assets	230,969	141,722
Capital		
Building - PCB shed	11,642	11,642
Computer hardware	34,922	32,663
Computer software	1,304	1,304
Distribution meters	101,381	101,389
Distribution system - overhead	2,070,333	2,054,379
- underground	27,784	27,784
Distribution transformers	251,995	231,082
Equipment and tools	7,603	7,603
	2,506,964	2,467,846
Less accumulated amortization	1,283,657	1,189,620
	1,223,307	1,278,226
Capital contributions, net	(67,014)	(34,179)
Total capital	1,156,293	1,244,047
	2,146,019	1,953,921

Contingency *[note 11]*

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

	2005	2004
	\$	\$
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable	231,784	201,785
Customer deposits	53,776	15,125
Payable to the Township of Terrace Bay	118,473	97,938
Current portion of due to Hydro One	43,836	—
Total current liabilities	447,869	314,848
Promissory note [note 4]	844,107	844,107
Due to Hydro One	54,791	—
Shareholder's equity		
Share capital		
Authorized		
Unlimited Class A common shares		
Unlimited Class B common shares		
Unlimited Class C common shares		
Unlimited Class D preferred shares, non-voting, non-cumulative		
Unlimited Class E preferred shares, non-voting, non-cumulative		
Unlimited Class F preferred shares, non-voting, non-cumulative		
Issued		
750 Class A common shares	750,000	750,000
Retained earnings	49,252	44,966
Total shareholder's equity	799,252	794,966
	2,146,019	1,953,921

Terrace Bay Superior Wires Inc.

Statement of Operations and Retained Earnings

Year ended December 31

2005

2004

	\$	\$
Revenue from the sale of energy <i>[note 6]</i>	1,612,110	1,669,227
Cost of bulk power purchased	1,170,052	1,271,284
Gross margin on energy sales	442,058	397,943
Other operating revenue <i>[note 7]</i>	26,439	21,466
	468,497	419,409
EXPENSES		
Administrative		
Billing and collecting	121,786	110,343
General	137,705	107,381
	259,491	217,724
Operating and maintenance		
Distribution	52,189	30,669
Metering	13,185	17,600
	65,374	48,269
	324,865	265,993
Earnings before the following	143,632	153,416
Amortization <i>[note 8]</i>	93,346	93,779
Interest on promissory note <i>[note 4]</i>	46,000	—
Earnings for year	4,286	59,637
Retained earnings (deficit), beginning of year	44,966	(14,671)
Retained earnings, end of year	49,252	44,966

See accompanying notes to the financial statements.

Terrace Bay Superior Wires Inc.

Statement of Cash Flows

Year ended December 31	2005	2004
	\$	\$
OPERATING ACTIVITIES		
Earnings for year	4,286	59,637
Add charges to earnings not involving a current payment of cash		
Amortization	93,346	93,779
	97,632	153,416
Net change in non-cash working capital balances related to operations <i>[note 10]</i>	132,833	(22,025)
Cash provided by operating activities	230,465	131,391
INVESTMENT ACTIVITY		
Additions to capital assets, net	(40,022)	(10,397)
Cash used in investment activity	(40,022)	(10,397)
FINANCING ACTIVITIES		
Contributions in aid of construction	35,763	—
Decrease (increase) in regulatory assets	(90,580)	4,091
Due to Hydro One	98,627	—
Cash provided by financing activities	43,810	4,091
Increase in cash and cash equivalents during year	234,253	125,085
Cash and cash equivalents, beginning of year	204,716	79,631
Cash and cash equivalents, end of year	438,969	204,716

See accompanying notes to the financial statements.

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2005

GENERAL

Terrace Bay Superior Wires Inc. is a wholly-owned subsidiary company of the Corporation of the Township of Terrace Bay, providing electrical distribution services to the inhabitants of the Township of Terrace Bay, as regulated by the Ontario Energy Board ("OEB").

1. REGULATION

The electricity market opened to competition on May 1, 2002 [note 14]. Upon market opening, the cost of power and all costs related to the operations of the electricity grid including transmission, connection and administration costs are to be flowed through to the consumer. Rates are typically established each year as set out in the Distribution Rate Handbook.

Bill 210 became law on December 9, 2002 and effectively implemented a rate cap for the cost of electricity consumed (as well as for delivery costs) by low-volume and designated customers. Retail settlement variance accounts and certain other accounts prescribed by the OEB have been defined as "Regulatory Assets" under Bill 210.

Bill 4, the Ontario Energy Board Amendment Act, 2003 came into effect December 18, 2003 and replaced the commodity rate cap with a two-tiered pricing structure, which was implemented April 1, 2004. This pricing structure remained in place until the OEB introduced a Regulated Rate Plan (fixed pricing) on April 1, 2005.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities", and reflect the significant accounting policies summarized below.

Rate setting

The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers, and the responsibility for ensuring the distribution companies fulfil obligations to connect and service customers. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments that have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non-regulated environment:

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2005

[a] Costs incurred to align systems and practices with the requirements of the future competitive electricity market in Ontario (Transition costs or Market Ready costs) may be deferred in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the Accounting Procedures Handbook for Electric Distribution Utilities. Under such regulation, certain costs are allowed to be deferred that would be expensed when incurred under Canadian GAAP. Terrace Bay Superior Wires Inc. is able to apply for the recovery of these costs in accordance with the guidelines and timetable for this process which is established each year by the OEB during the rate application process.

[b] Terrace Bay Superior Wires Inc. provides for payments-in-lieu ("PILs") of corporate income taxes relating to its regulated business using the taxes payable method as recommended for rate-regulated enterprises which expect that future income taxes will be included in the approved rate charged to customers in the future and are expected to be recovered by future customers.

[c] Regulatory assets

Retail settlement variance accounts track the differences between the amount billed plus accrued unbilled revenue and the purchased cost of power since market opening. Adjustments to record the variances have been added (deducted) from gross revenue or cost of power as appropriate to reflect the "flow-through" nature of the costs.

Cash and cash equivalents

Cash and cash equivalents consist of cash on deposit and cashier float.

Capital assets

Capital assets are stated at cost. Gains or losses at retirement or disposition of such assets are credited or charged to other income. Amortization is provided on a straight-line basis for capital assets over their estimated service lives at the following annual rates:

General plant	2% to 4%
Other capital assets	10% to 20%

Pension plan

Terrace Bay Superior Wires Inc. provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (the "Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund [note 9]. Terrace Bay Superior Wires Inc. recognizes the expense related to this plan as contributions are made.

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2005

Revenue recognition

Revenue is recorded on the basis of regular meter readings. Estimates of customer usage since the last meter reading date to the end of the year are recorded as unbilled revenue.

Capital contributions

Capital contributions are required contributions received from outside sources, used to finance additions to capital assets. Capital contributions are treated as a "credit" contra account included in the determination of capital assets. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related capital assets.

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates.

Organization costs

Organization costs are legal and other professional costs associated with the corporate restructuring and the transfer of assets from the Electrical Utility. The organization costs are being amortized on a straight-line basis over five years.

Corporate income taxes and capital taxes

The current tax-exempt status of Terrace Bay Superior Wires Inc. under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) reflects the fact that Terrace Bay Superior Wires Inc. is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of Terrace Bay Superior Wires Inc., or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of Terrace Bay Superior Wires Inc.

Commencing October 1, 2001, Terrace Bay Superior Wires Inc. was required, under the Electricity Act, 1998, to make PILs of corporate taxes to the 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 Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2005

Terrace Bay Superior Wires Inc. provides for PILs relating to its rate regulated enterprise using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Terrace Bay Superior Wires Inc. at that time.

3. ORGANIZATION COSTS

	2005 \$	2004 \$
Balance, beginning of year	6,672	6,672
Less accumulated amortization	6,672	5,339
Balance, end of year	—	1,333

Amortization for the year is \$1,333 [2004 - \$1,335].

4. PROMISSORY NOTE

Demand promissory note is secured by a general security agreement and payable to The Corporation of the Township of Terrace Bay, with interest to be established annually at a variable rate per annum between 0% and 7-1/4%. Principal repayment in the next twelve months is expected to be \$nil.

5. BANK CREDITS

[a] Terrace Bay Superior Wires Inc. has a letter of credit available to them in the amount of \$128,000 through the Canadian Imperial Bank of Commerce ("CIBC") of which \$nil was utilized at December 31, 2005. This credit will be used by Terrace Bay Superior Wires Inc. to assist in meeting its prudential obligations to the Independent Electricity System Operator ("IESO"). The letter of credit is subject to an annual fee [1.3% at year-end]. An interest rate has not been established on future drawings as this would be negotiated with the CIBC at the time of such drawings.

[b] Terrace Bay Superior Wires Inc. has a revolving term credit available to them in the amount of \$100,000 [2004 - \$100,000] of which \$nil was utilized at December 31, 2005. This credit will be used by Terrace Bay Superior Wires Inc. to assist in making power purchases from the IESO. The credit bears interest at bank prime. Prime at December 31, 2005 was 5.25%.

Security for the bank credits include a general security agreement over all assets of Terrace Bay Superior Wires Inc. and a subordination agreement with respect to the promissory note payable to the Township of Terrace Bay.

Terrace Bay Superior Wires Inc.
Notes to the Financial StatementsDecember 31, 2005

6. REVENUE FROM THE SALE OF ENERGY

	2005 \$	2004 \$
Residential	578,920	626,133
Commercial	394,768	417,069
Street lighting	13,301	15,656
Wholesale market services	102,097	120,915
Connection charges	82,777	91,511
Distribution services	440,247	397,943
	1,612,110	1,669,227

7. OTHER OPERATING REVENUE

	2005 \$	2004 \$
Late payment charges	5,101	6,947
Interest	10,810	9,940
Miscellaneous	10,528	4,579
	26,439	21,466

8. AMORTIZATION

Amortization provided during the year consists of:

	2005 \$	2004 \$
Amortization of general plant	94,941	93,941
Amortization of capital contributions	(2,928)	(1,497)
Amortization of organization costs	1,333	1,335
	93,346	93,779

9. PENSION PLAN

Terrace Bay Superior Wires Inc. incurred current service pension costs for the year ended December 31, 2005 of \$4,374 [2004 - \$3,822].

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2005

10. STATEMENT OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2005 \$	2004 \$
Decrease (increase) in current assets		
Accounts receivable	54,277	(42,399)
Unbilled revenue	(16,917)	23,312
Prepaid expenses	6,288	(3,124)
	43,648	(22,211)
Increase (decrease) in current liabilities		
Accounts payable	29,999	30,029
Customer deposits	38,651	(7,204)
Payable to the Township of Terrace Bay	20,535	(22,639)
	89,185	186
	132,833	(22,025)

11. CONTINGENCY

A class action claiming \$500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association ("EDA"), formerly known as the Municipal Electric Association ("MEA"), is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Corporation.

12. RELATED PARTY TRANSACTIONS

Due to the nature and volume of transactions between Terrace Bay Superior Wires Inc. and The Corporation of the Township of Terrace Bay, the sole shareholder, it is impractical to detail the transactions that take place between these organizations. The majority of the transactions are related to the pass through of water collections to the Township.

Terrace Bay Superior Wires Inc. Notes to the Financial Statements

December 31, 2005

13. CORPORATE INCOME AND CAPITAL TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between Terrace Bay Superior Wires Inc.'s reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2005 \$	2004 \$
Earnings before provision for taxes	4,286	59,637
Statutory Canadian federal and provincial income tax rate	18.62%	18.62%
Expected provision	800	11,104
Decrease in income taxes due to losses carried forward from prior years	(3,685)	(12,815)
Timing differences		
Amortization and capital cost allowance	3,240	1,807
Amortization and eligible capital expenditure amortization	(355)	(96)
Effective tax rate	0%	0%

Future income taxes relating to Terrace Bay Superior Wires Inc. have not been recorded in the accounts as they are expected to be recovered through future revenues. As a result, a current year income tax recovery of \$3,685 has not been recorded. As at December 31, 2005, future income tax assets of \$47,700 based on substantively enacted income tax rates, have not been recorded. Of this amount, \$nil relates to non-capital losses.

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2005

14. ELECTRIC INDUSTRY RESTRUCTURING AND REGULATION

The Energy Competition Act, 1998 (the "Act") was given Royal Assent on October 30, 1998. The Act provides for a competitive market in the sale of electricity, in addition to the regulation of the monopoly electricity delivery system in the Province of Ontario, by the OEB. The electricity marketplace has been deregulated. Open Access commenced on May 1, 2002, the date on which transmitters and distributors were required to provide generators, retailers and consumers with non-discriminatory access to the transmission and distribution systems in Ontario in accordance with their licences under the Electricity Act, 1998. Terrace Bay Superior Wires Inc. was obligated to provide a letter of credit to the IESO in the amount of \$128,000, two weeks prior to Open Access.

The OEB has regulatory authority over the electricity distribution sector. The Act sets out the OEB's powers to issue a distribution licence which must be obtained by any person owning or operating a distribution system under the revised Ontario Energy Board Act, 1998 (the "new OEB Act" - a component of the new Act). The new OEB Act allows the OEB to prescribe licence requirements and conditions to electricity distributors which may include, among other considerations, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing/process requirements for rate-setting purposes.

15. COMMITMENT

On November 30, 2001, Terrace Bay Superior Wires Inc. entered into an agreement with Thunder Bay Hydro Electricity Distribution Inc. ("TBHEDI"), whereby TBHEDI is to provide billing functions to Terrace Bay Superior Wires Inc. for a term of five years. Terrace Bay Superior Wires Inc. is entitled to terminate this agreement prior to the end of the term on 180 days prior written notice and a cancellation fee based on a fixed amount and a percentage of the present value of future payments that would have been paid had the contract not been cancelled.

16. CONTINGENT LIABILITY

Terrace Bay Superior Wires Inc. will incur future costs associated with the disposal of hazardous waste products. Although these costs cannot be reasonably determined at this time a contingent liability exists.

Grant Thornton

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Grant Thornton LLP
Chartered Accountants
Management Consultants

Auditors' Report

To the Shareholder of
Terrace Bay Superior Wires Inc.

We have audited the balance sheet of **Terrace Bay Superior Wires Inc.** as at December 31, 2006 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our 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 Corporation 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.

Grant Thornton LLP

Thunder Bay, Canada
February 16, 2007

Chartered Accountants
Licensed Public Accountants

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Terrace Bay Superior Wires Inc. Balance Sheet

December 31	2006	2005
	\$	\$
ASSETS		
Current		
Cash and cash equivalents	387,120	438,969
Accounts receivable	228,839	130,282
Unbilled revenue	151,398	187,843
Prepaid expenses	4,559	1,663
Total current assets	771,916	758,757
Long-term		
Regulatory assets	366,240	230,969
Total long-term assets	366,240	230,969
Capital		
Building - PCB shed	11,642	11,642
Computer hardware	35,147	34,922
Computer software	1,304	1,304
Distribution meters	101,178	101,381
Distribution system - overhead	2,091,233	2,070,333
- underground	27,784	27,784
Distribution transformers	251,995	251,995
Equipment and tools	7,603	7,603
	2,527,886	2,506,964
Less accumulated amortization	1,376,862	1,283,657
	1,151,024	1,223,307
Capital contributions, net	(64,086)	(67,014)
Total capital	1,086,938	1,156,293
	2,225,094	2,146,019

Contingency [note 10]

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

	2006	2005
	\$	\$
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable	293,240	231,784
Customer deposits	16,333	53,776
Payable to the Township of Terrace Bay	40,000	118,473
Current portion of due to Hydro One	84,696	43,836
Payments in lieu of income taxes payable	11,694	—
Total current liabilities	445,963	447,869
Promissory note [note 3]	844,107	844,107
Due to Hydro One	101,867	54,791
Shareholder's equity		
Share capital		
Authorized		
Unlimited Class A common shares		
Unlimited Class B common shares		
Unlimited Class C common shares		
Unlimited Class D preferred shares, non-voting, non-cumulative		
Unlimited Class E preferred shares, non-voting, non-cumulative		
Unlimited Class F preferred shares, non-voting, non-cumulative		
Issued		
750 Class A common shares	750,000	750,000
Retained earnings	83,157	49,252
Total shareholder's equity	833,157	799,252
	2,225,094	2,146,019

Terrace Bay Superior Wires Inc. **Statement of Operations and Retained Earnings**

Year ended December 31	2006	2005
	\$	\$
Revenue from the sale of energy <i>[note 5]</i>	1,587,286	1,612,110
Cost of bulk power purchased	1,157,315	1,170,052
Gross margin on energy sales	429,971	442,058
Other operating revenue <i>[note 6]</i>	42,638	26,439
	472,609	468,497
EXPENSES		
Administrative		
Billing and collecting	116,797	121,786
General	120,325	137,705
	237,122	259,491
Operating and maintenance		
Distribution	47,496	52,189
Metering	11,913	13,185
	59,409	65,374
	296,531	324,865
Earnings before the following	176,078	143,632
Amortization <i>[note 7]</i>	90,479	93,346
Interest on promissory note <i>[note 3]</i>	40,000	46,000
Earnings before income taxes	45,599	4,286
Provision for payments in lieu of income taxes	11,694	—
Earnings for year	33,905	4,286
Retained earnings, beginning of year	49,252	44,966
Retained earnings, end of year	83,157	49,252

See accompanying notes to the financial statements.

Terrace Bay Superior Wires Inc.

Statement of Cash Flows

Year ended December 31	2006	2005
	\$	\$
OPERATING ACTIVITIES		
Earnings for year	33,905	4,286
Add charges to earnings not involving a current payment of cash		
Amortization	90,479	93,346
	124,384	97,632
Net change in non-cash working capital balances related to operations <i>[note 9]</i>	(107,774)	132,833
Cash provided by operating activities	16,610	230,466
INVESTMENT ACTIVITY		
Additions to capital assets, net	(21,124)	(40,022)
Cash used in investment activity	(21,124)	(40,022)
FINANCING ACTIVITIES		
Contributions in aid of construction	—	35,763
Increase in regulatory assets	(135,271)	(90,580)
Due to Hydro One	87,936	98,627
Cash (used in) provided by financing activities	(47,335)	43,810
Increase (decrease) in cash and cash equivalents during year	(51,849)	234,253
Cash and cash equivalents, beginning of year	438,969	204,716
Cash and cash equivalents, end of year	387,120	438,969

See accompanying notes to the financial statements.

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2006

GENERAL

Terrace Bay Superior Wires Inc. is a wholly-owned subsidiary company of the Corporation of the Township of Terrace Bay, providing electrical distribution services to the inhabitants of the Township of Terrace Bay, as regulated by the Ontario Energy Board ("OEB").

1. REGULATION

The electricity market opened to competition on May 1, 2002 [note 13]. Upon market opening, the cost of power and all costs related to the operations of the electricity grid including transmission, connection and administration costs are to be flowed through to the consumer. Rates are typically established each year as set out in the Distribution Rate Handbook.

Bill 210 became law on December 9, 2002 and effectively implemented a rate cap for the cost of electricity consumed (as well as for delivery costs) by low-volume and designated customers. Retail settlement variance accounts and certain other accounts prescribed by the OEB have been defined as "Regulatory Assets" under Bill 210.

Bill 4, the Ontario Energy Board Amendment Act, 2003 came into effect December 18, 2003 and replaced the commodity rate cap with a two-tiered pricing structure, which was implemented April 1, 2004. This pricing structure remained in place until the OEB introduced a Regulated Rate Plan (fixed pricing) on April 1, 2005.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), including accounting principles prescribed by the OEB in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities", and reflect the significant accounting policies summarized below.

Rate setting

The Ontario Energy Board Act, 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers, and the responsibility for ensuring the distribution companies fulfil obligations to connect and service customers. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments that have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non-regulated environment:

Terrace Bay Superior Wires Inc.

Notes to the Financial Statements

December 31, 2006

[a] Costs incurred to align systems and practices with the requirements of the future competitive electricity market in Ontario (Transition costs or Market Ready costs) may be deferred in accordance with the criteria set out in the OEB's Electricity Distribution Rate Handbook and the Accounting Procedures Handbook for Electric Distribution Utilities. Under such regulation, certain costs are allowed to be deferred that would be expensed when incurred under Canadian GAAP. Terrace Bay Superior Wires Inc. is able to apply for the recovery of these costs in accordance with the guidelines and timetable for this process which is established each year by the OEB during the rate application process.

[b] Terrace Bay Superior Wires Inc. provides for payments-in-lieu ("PILs") of corporate income taxes relating to its regulated business using the taxes payable method as recommended for rate-regulated enterprises which expect that future income taxes will be included in the approved rate charged to customers in the future and are expected to be recovered by future customers.

[c] Regulatory assets.

Retail settlement variance accounts track the differences between the amount billed plus accrued unbilled revenue and the purchased cost of power since market opening. Adjustments to record the variances have been added (deducted) from gross revenue or cost of power as appropriate to reflect the "flow-through" nature of the costs.

Cash and cash equivalents

Cash and cash equivalents consist of cash on deposit and cashier float.

Capital assets

Capital assets are stated at cost. Gains or losses at retirement or disposition of such assets are credited or charged to other income. Amortization is provided on a straight-line basis for capital assets over their estimated service lives at the following annual rates:

General plant	2% to 4%
Other capital assets	10% to 20%

Pension plan

Terrace Bay Superior Wires Inc. provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (the "Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund [note 8]. Terrace Bay Superior Wires Inc. recognizes the expense related to this plan as contributions are made.

Terrace Bay Superior Wires Inc. Notes to the Financial Statements

December 31, 2006

Revenue recognition

Revenue is recorded on the basis of regular meter readings. Estimates of customer usage since the last meter reading date to the end of the year are recorded as unbilled revenue.

Capital contributions

Capital contributions are required contributions received from outside sources, used to finance additions to capital assets. Capital contributions are treated as a "credit" contra account included in the determination of capital assets. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related capital assets.

Use of estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenue and expenses for the year. Actual results could differ from those estimates.

Organization costs

Organization costs are legal and other professional costs associated with the corporate restructuring and the transfer of assets from the Electrical Utility. The organization costs are being amortized on a straight-line basis over five years.

Corporate income taxes and capital taxes

The current tax-exempt status of Terrace Bay Superior Wires Inc. under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) reflects the fact that Terrace Bay Superior Wires Inc. is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of Terrace Bay Superior Wires Inc., or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of Terrace Bay Superior Wires Inc.

Commencing October 1, 2001, Terrace Bay Superior Wires Inc. was required, under the Electricity Act, 1998, to make PILs of corporate taxes to the 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 Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Terrace Bay Superior Wires Inc. Notes to the Financial Statements

December 31, 2006

Terrace Bay Superior Wires Inc. provides for PILs relating to its rate regulated enterprise using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Terrace Bay Superior Wires Inc. at that time.

3. PROMISSORY NOTE

Demand promissory note is secured by a general security agreement and payable to The Corporation of the Township of Terrace Bay, with interest to be established annually at a variable rate per annum between 0% and 7-1/4%. Principal repayment in the next twelve months is expected to be \$nil.

4. BANK CREDITS

Terrace Bay Superior Wires Inc. has a revolving term credit available to them in the amount of \$100,000 [2005 - \$100,000] of which \$nil was utilized at December 31, 2006. This credit will be used by Terrace Bay Superior Wires Inc. to assist in making power purchases. The credit bears interest at bank prime. Prime at December 31, 2006 was 5.25%.

5. REVENUE FROM THE SALE OF ENERGY

	2006 \$	2005 \$
Residential	465,467	481,957
Commercial	383,121	394,768
Street lighting	16,968	13,301
Energy resale	1,664	—
Wholesale market services & low voltage billed	129,239	102,097
Network revenue	86,246	96,963
Connection charges	74,610	82,777
Distribution services	429,971	440,247
	1,587,286	1,612,110

6. OTHER OPERATING REVENUE

	2006 \$	2005 \$
Late payment charges	5,749	5,101
Interest	22,866	10,810
Miscellaneous	14,023	10,528
	42,638	26,439

Terrace Bay Superior Wires Inc. Notes to the Financial Statements

December 31, 2006

7. AMORTIZATION

Amortization provided during the year consists of:

	2006 \$	2005 \$
Amortization of general plant	93,407	94,941
Amortization of capital contributions	(2,928)	(2,928)
Amortization of organization costs	—	1,333
	90,479	93,346

8. PENSION PLAN

Terrace Bay Superior Wires Inc. incurred current service pension costs for the year ended December 31, 2006 of \$4,384 [2005 - \$4,374].

9. STATEMENT OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2006 \$	2005 \$
Decrease (Increase) in current assets		
Accounts receivable	(98,557)	54,277
Unbilled revenue	36,445	(16,917)
Prepaid expenses	(2,896)	6,288
	(65,008)	43,648
Increase (decrease) in current liabilities		
Accounts payable	61,456	29,999
Customer deposits	(37,443)	38,651
Payable to the Township of Terrace Bay	(78,473)	20,535
Payments in lieu of income taxes payable	11,694	—
	(42,766)	89,185
	(107,774)	132,833

Terrace Bay Superior Wires Inc. Notes to the Financial Statements

December 31, 2006

10. CONTINGENCY

A class action claiming \$500 million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electricity Distributors Association ("EDA"), formerly known as the Municipal Electric Association ("MEA"), is undertaking the defence of this class action. At this time, it is not possible to quantify the effect, if any, on the financial statements of the Corporation.

11. RELATED PARTY TRANSACTIONS

Terrace Bay Superior Wires Inc. is related to the following companies:

The Township of Terrace Bay

Wholly-owned subsidiary of The Corporation of the Township of Terrace Bay

[a] Due to the nature and volume of the revenue transactions between Terrace Bay Superior Wires Inc. and The Corporation of the Township of Terrace Bay, the sole shareholder, it is impractical to detail the revenue transactions that take place between these organizations.

[b] Included in these financial statements are expenditure transactions with The Township of Terrace Bay as follows:

	2006 \$	2005 \$
Operational expenses		
Management and emergency back-up	10,200	10,000
Billing	8,160	8,000
Collections	45,900	45,000
	64,260	63,000
Supplies and resources		
Rental of storage space	2,575	2,575
Rental of operating space	4,080	4,000
Supplies, postage and phone	5,585	5,475
	12,240	12,050
Financing expenses		
Interest on promissory note	40,000	46,000

Terrace Bay Superior Wires Inc. Notes to the Financial Statements

December 31, 2006

[c] The year-end due to related party balances included in accounts payable are as follows:

	2006 \$	2005 \$
Due to the Township of Terrace Bay	40,000	118,473
Promissory note	844,107	844,107

[d] There are no balances due from a related party included in accounts receivable.

12. INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between Terrace Bay Superior Wires Inc.'s reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2006 \$	2005 \$
Earnings before provision for taxes	45,599	4,286
Statutory Canadian federal and provincial income tax rate	18.62%	18.62%
Expected provision	8,490	800
Decrease in income taxes due to losses carried forward from prior years	—	(3,685)
Timing differences		
Amortization and capital cost allowance	3,804	3,240
Amortization and eligible capital expenditure amortization	(600)	(355)
Effective tax rate	18.62%	0%

Future income taxes relating to Terrace Bay Superior Wires Inc. have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax assets of \$48,000 based on substantively enacted income tax rates, have not been recorded. Of this amount, \$nil relates to non-capital losses.

Terrace Bay Superior Wires Inc.
Notes to the Financial Statements
 December 31, 2006

13. ELECTRIC INDUSTRY RESTRUCTURING AND REGULATION

The Energy Competition Act, 1998 (the "Act") was given Royal Assent on October 30, 1998. The Act provides for a competitive market in the sale of electricity, in addition to the regulation of the monopoly electricity delivery system in the Province of Ontario, by the OEB. The electricity marketplace has been deregulated. Open Access commenced on May 1, 2002, the date on which transmitters and distributors were required to provide generators, retailers and consumers with non-discriminatory access to the transmission and distribution systems in Ontario in accordance with their licences under the Electricity Act, 1998. Terrace Bay Superior Wires Inc. was obligated to provide a letter of credit to the IESO in the amount of \$128,000, two weeks prior to Open Access.

The OEB has regulatory authority over the electricity distribution sector. The Act sets out the OEB's powers to issue a distribution licence which must be obtained by any person owning or operating a distribution system under the revised Ontario Energy Board Act, 1998 (the "new OEB Act" - a component of the new Act). The new OEB Act allows the OEB to prescribe licence requirements and conditions to electricity distributors which may include, among other considerations, specified accounting records, regulatory accounting principles, separation of accounts for separate businesses and filing/process requirements for rate-setting purposes.

14. CONTINGENT LIABILITY

Terrace Bay Superior Wires Inc. will incur future costs associated with the disposal of hazardous waste products. Although these costs cannot be reasonably determined at this time a contingent liability exists.

15. SUBSEQUENT EVENTS

Subsequent to the year-end, the following occurred:

- [i] The Corporation of the Township of Terrace Bay (sole shareholder), has passed a resolution to enter into negotiations with Hydro One Networks Inc. that is expected to result in a sale of the utility. If an agreement is reached the sale is expected to close in the 2007 calendar year.
- [ii] It was discovered that Hydro One has incorrectly invoiced Terrace Bay Superior Wires Inc. for Retail Transmission Service Connection Charges for the period from May, 2002 to April, 2007.

The amount of the over billing is not determinable at this time and will be recorded at the time the amount can be reasonably determined and the OEB approves the repayment plan. Since the costs associated with this correction are pass through costs, it is expected that the impact of this adjustment will not affect the financial position of the company.

Terrace Bay Superior Wires Inc.
Notes to the Financial StatementsDecember 31, 2006

16. FINANCIAL INSTRUMENTS**[a] Financial instruments**

Management estimates that the fair values of all financial assets and liabilities are not materially different from their carrying values.

[b] Credit risk

Credit risk is the risk that a counter party will fail to discharge its obligation to Terrace Bay Superior Wires Inc. reducing the expected cash inflow from the Corporation assets recorded at the balance sheet date. Credit risk can be concentrated in debtors that are similarly affected by economic or other conditions. The Corporation provides for an allowance for doubtful accounts to absorb credit losses. The Corporation has assessed that there are no significant concentrations of credit risk with respect of any class of financial assets.

[c] Interest rate risk

The Corporation is exposed to interest rate risk for certain of its financial assets and liabilities. Under the revolving terms of credit, the Corporation may have short-term borrowings for working capital purposes, which would expose the Corporation to fluctuations in short-term interest rates (borrowings in the form of prime rate loans in Canadian dollars).

SECTION - 1.5.1

**Hydro One Networks Inc.
Annual Reports – 2005 and 2006
Annual Information Forms – 2005 and 2006**



We start every day with
100 years of experience



2005 Annual Report

1906–2005

Powering Ontario for 100 years.

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Standing Tall

Front Cover: Line maintainer Dan Butters does maintenance on a tower outside of London, Ontario.



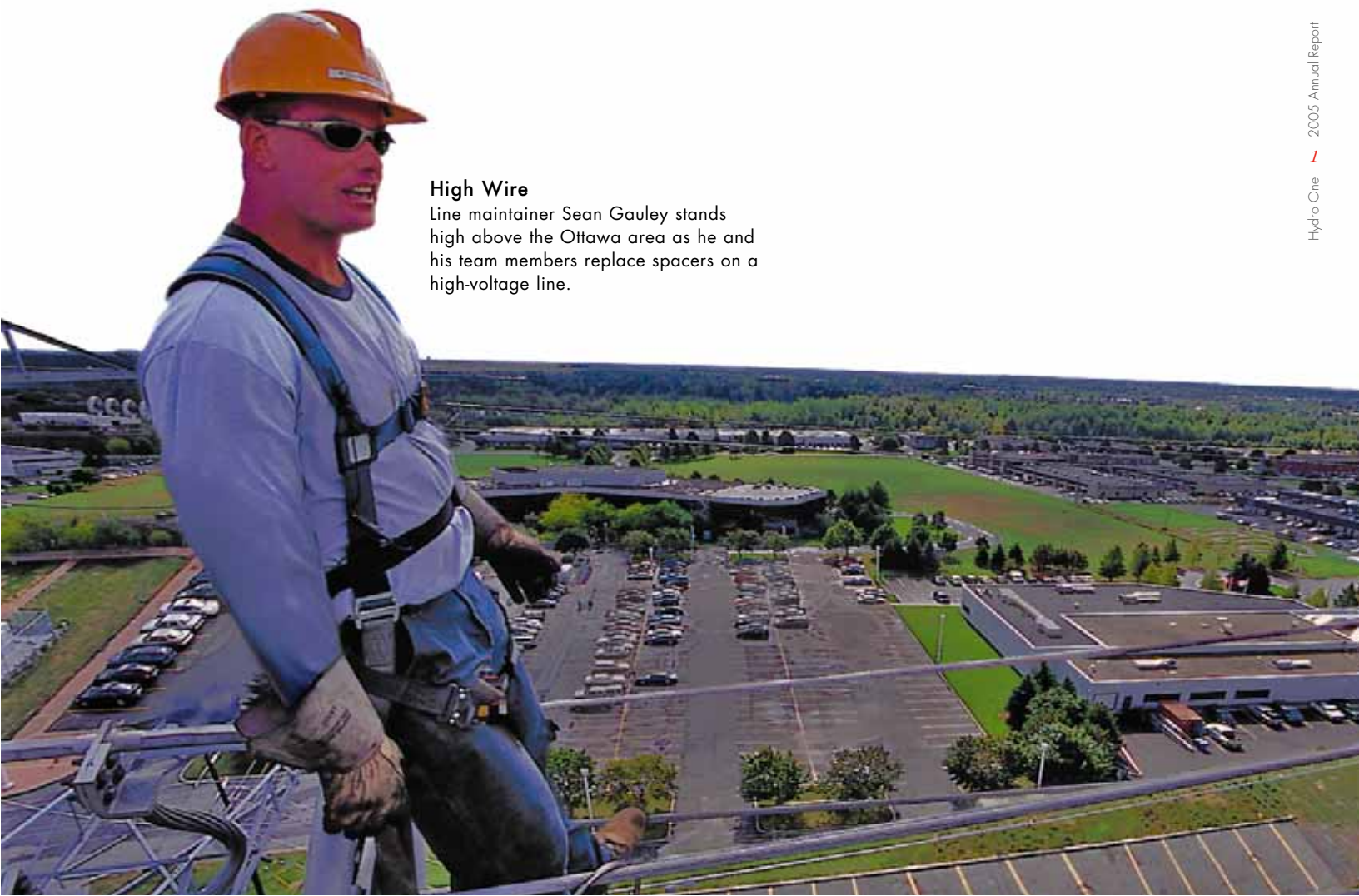
Safety Service Reliability Pride Value

At the flick of a switch electricity arrives safely and reliably in your homes. It powers your businesses and helps you keep them growing. Our job is to take care of the system that enables electricity to flow to you, no matter where you live in Ontario. We work to make sure this vital resource is there when you need it. With your help, we're ensuring Ontario gets the most out of its electricity system.

We do this by focusing on our five values.

High Wire

Line maintainer Sean Gauley stands high above the Ottawa area as he and his team members replace spacers on a high-voltage line.





Hydro One Inc.

Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom. The subsidiaries are necessary to meet legislative and regulatory requirements.

Hydro One Networks Inc.

Represents the significant majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Inc.

Distributes electricity to one of the fastest growing urban centres in Canada, just 30 km outside of Toronto.

Hydro One Remote Communities Inc.

Operates and maintains the generation and distribution assets used to supply electricity to 18 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.

Markets our fibre optic capacity to business customers and represents less than 1 per cent of our total assets.

— Accomplishments in 2005 —

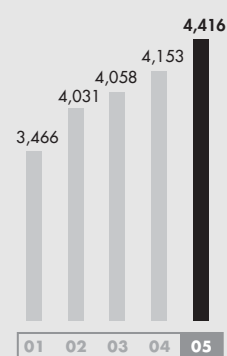
- Completed the Parkway transformer station on time and budget. This facility improves the reliability of the transmission system serving the electricity demand in the Greater Toronto Area (GTA) and helped facilitate the shut down of the Lakeview generating station.
- To better serve Canada's largest city, we began construction of two underground cable circuits to reinforce our electricity transmission facilities in downtown Toronto.
- To improve reliability and supply in southern Ontario, we started construction of a new 76-kilometre 230-kV line in the Niagara region.
- To secure necessary rates for future distribution work programs investments and system costs, Hydro One prepared and filed evidence with the Ontario Energy Board (OEB).
- Significantly improved or maintained customer satisfaction across all of our customer segments.
- Improved efficiency through an increasingly flexible workforce which is reflected in our strong financial results and our ability to achieve more for our customers and the people of Ontario.

— Key Credit Strengths —

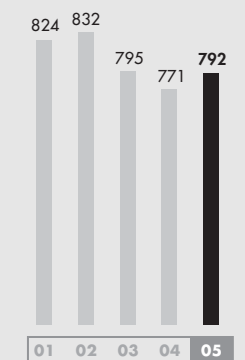
- Hydro One owns and operates the largest electricity delivery system in Ontario and one of the largest in North America
- Experienced management team focused on the core electricity delivery business
- Highly skilled and experienced workforce with first-class operating systems
- Recognized industry leader in the development and implementation of a safe workplace
- A track record of stable and predictable earnings from our regulated transmission and distribution businesses
- Conservative capital structure and strong cash flow performance



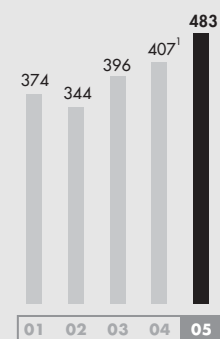
Year ended December 31 (Canadian dollars in millions)	2005	2004	\$ Change	% Change
Revenues	4,416	4,153	263	6
Purchased power	2,131	1,987	144	7
Operating costs	1,279	1,251	28	2
Net income	483	407 ^{1,2}	76 ²	19 ²
Net cash from operations	1,170	911	259	28
Statistics				
Transmission – units transmitted (TWb) ³	157.0	153.4	3.6	2
Average Ontario 60-minute peak demand (MW) ³	23,074	22,375	699	3
Distribution – units distributed to Hydro One customers (TWb) ³	29.7	28.5	1.2	4



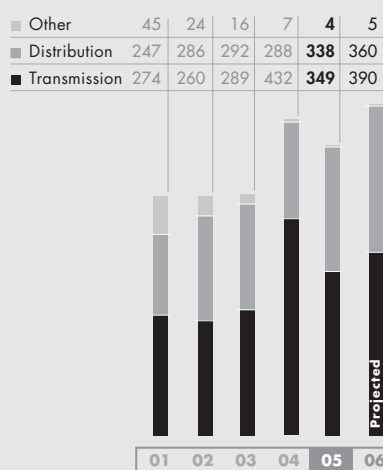
Revenues
Year ended December 31
(Cdn \$ millions)



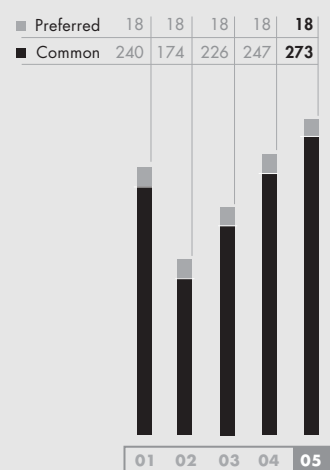
Operation, Maintenance and Administration Costs
Year ended December 31
(Cdn \$ millions)



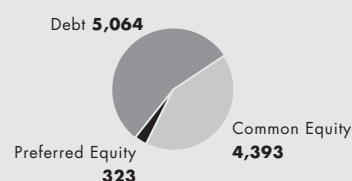
Net Income
Year ended December 31
(Cdn \$ millions)



Capital Expenditure
Year ended December 31
(Cdn \$ millions)



Dividends
Year ended December 31
(Cdn \$ millions)



Capital Structure
December 31, 2005
(Cdn \$ millions)

¹ Net income for 2004 was \$498 million, including a one-time regulatory recovery of \$91 million.

² Based on 2004 net income of \$498 million, which includes a one-time regulatory recovery of \$91 million, 2005 net income was lower by \$15 million, or 3%.

³ System-related statistics include preliminary figures for December.

The Company's excellent results reflect Hydro One's continued commitment to transparent, prudent management of this vital provincial asset.

In 2005, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, skillfully navigating the operational challenges posed by one of the hottest summers on record that set new record peaks for demand. Hydro One's previous investments in its system paid off and the Company embarked on several large projects to ensure reliable supply for the people of Ontario.

In 2005, Hydro One continued its track record of strong financial performance. The Company's net income in 2005 increased \$76 million, or 19%, to \$483 million compared to 2004, putting aside the impact of last year's one-time regulatory recovery. This increase primarily reflects higher revenues within our transmission and distribution businesses, including the impact of the summer's record heat. During the heat wave, Hydro One

maintained an intense focus on its operations over the summer months to ensure the reliable delivery of electricity across the province.

As Chair of Hydro One, it's my role to ensure that the Company operates in a transparent, accountable and responsible way. Hydro One conforms to the highest standards of corporate governance in our relationship with our shareholder and in the fulfillment of our fiduciary responsibilities as a Board. The Board of Directors in 2005 was highly engaged, ensuring Hydro One remains focused on maintaining a strong, fiscally responsible and reliable electricity system that meets today's needs and is prepared for the challenges that lay ahead. This year, Hydro One focused on new securities regulations and is well positioned to meet these new requirements set out by the Ontario Securities Commission.

The Company's excellent results reflect Hydro One's ongoing commitment to the transparent, strong and focused leadership of our CEO, Tom Parkinson and our ongoing commitment to prudent management of this vital provincial asset. Hydro One made critical investments both in transmission and distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Total capital and operation, maintenance and administrative expenditures for 2005 were \$1,483 million. In addition, Hydro One paid its shareholder, the Province of Ontario, dividends of \$291 million, and recorded \$198 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province. The Board expects continued strong, stable financial performance.



I would like to take this opportunity to express my thanks to the Board members for their contribution and dedication. I would also like to especially thank retiring Board members Geoffrey Beattie, Adam Zimmerman and Dr. Murray Frum. As directors, each of them made outstanding contributions to the continued success of Hydro One.

On behalf of the Board of Directors, I would like to thank all of Hydro One's people for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.

A handwritten signature in black ink, appearing to read 'R. Burak'.

Rita Burak

Chair, Hydro One Inc.

Our goal is to be the best transmission and distribution business in North America.

We start every day with 100 years of experience.

I look at the black and white photographs on the walls of our boardroom and I see a proud history. Using draught horses, steam power and raw force of will, the people of Hydro Electric Power Commission (H.E.P.C.) connected the power of Niagara Falls to Ontario communities. Those first transmission lines brought more than electricity. They brought prosperity. They brought a higher standard of living. They brought a better future. The power delivery system that gradually spread to connect almost every community in Ontario meant that Ontario businesses, communities and families have prospered and grown in the last century. Today we continue that work. We deliver the electricity that is the very lifeblood of Ontario's economy.

In 2005, we worked hard to integrate new sources of generation into the system. We've begun construction of our Niagara Reinforcement Project to upgrade the transmission line that delivers the power produced in Niagara Falls to the rest of Southern Ontario. By upgrading this line, we will be able to deliver an additional 800 MW of electricity to where it needs to be. The new Parkway transformer station in the GTA was completed on time and on

budget, safely facilitating the decommissioning of the coal-fired Lakeview generating station. Work has also begun on an underground cable in downtown Toronto to improve supply flexibility to Canada's largest city.

In 2005, Hydro One faced one of the hottest summers on record. With 45 days with temperatures above 30 degrees, the aging transmission system was stretched to its very capacity. But it held. It held because we've invested wisely in our systems over the years. It held because our team knows how to get the very most out of Ontario's electricity highway. While I'm proud that our system and our people were able to meet the challenges of the summer, I also believe that as demand increases we need to find better ways of doing things. Part of the answer will be found in working with our customers to find conservation solutions that work. In 2005, we had some success with conservation pilot projects and in 2006 we are looking to achieve more.

2005 was a dynamic year for our company. Hydro One earned a profit of \$483 million and we paid our shareholder, the Province of Ontario an excellent dividend. We remain committed to earning a healthy return for our shareholder while ensuring Ontario's electricity delivery



system can continue to perform at an optimal level long into the future. Our stable and strong financial results this year were consistent with our expectations.

By 2010, our goal is to be the best transmission and distribution business in North America. What does this mean? We want to have the best safety record in the world, with zero serious injuries and zero serious near misses. We have top quartile reliability in transmission and are working towards the same in distribution when compared against similar utilities. Customer satisfaction, where major gains have been made in the last two years, is targeted to reach 90 per cent across all segments. We will continue to deliver shareholder value through fair transmission and distribution rates, prudent expenditures, employee productivity improvements and excellent operating efficiency.

Stable and strong are not euphemisms for static or stationary. The electricity industry, after 100 years of rich history in Ontario, is possibly at one of its most critical junctures. New transmission facilities are needed to facilitate the delivery of new supply to customers, to reduce constraints on the system, and improve our ability to import electricity. Only by improving cooperation and

coordination between communities, regulators and industry partners can we continue to reliably deliver the electricity that Ontario depends upon. Only by realizing that we are all working towards the same goal – safe reliable electricity and continued prosperity for Ontarians – can we move quickly enough to put the necessary and proper assets in place.

I'd like to thank the people of Hydro One for their commitment to our strategic direction, and for the fantastic job they do everyday. It shows in our results and in the satisfaction of our customers. Much has changed in the last century. We do things differently, we use different tools and we work much more safely. But one thing has not changed. We continue to focus on providing the people of Ontario with an electricity delivery system that allows them to prosper now and long into the future.

Tom Parkinson

President and Chief Executive Officer, Hydro One Inc.



Connecting Ontario

Left: Stringing the first transmission lines on steel towers to connect the Niagara area to southern Ontario communities. February, 1910.

Broad Shoulders

Above: Hydro One's high-voltage system includes more than 28,000 circuit kilometres of lines supported by nearly 48,000 towers all over Ontario. In 2005, work was started to upgrade 76 km of line to allow more electricity to flow from the Niagara region.

“We are off now, just let anyone try and stop us.”

With that sentence, Sir Adam Beck opened the Wasdell Falls generating station. Beck, also known as the father of Ontario’s electricity system, had a vision that electricity was the way to a bright future for everyone in Ontario. He pushed for the construction of generating stations to produce electricity on a massive scale.

But it wasn’t enough to just produce power. Beck believed that only by delivering power to all parts of Ontario would everyone share in the economic prosperity that electricity brings.

He oversaw the development of a network of transmission and distribution lines that has now grown to stretch more than 150,000 kilometres across all parts of Ontario.

His vision and energy helped make Ontario the economic engine of Canada. Without electricity, our world would be a very different place. Hydro One continues to focus on delivering electricity and economic prosperity to the people of Ontario.

1906

The Hydro-Electric Power Commission is created to build transmission lines to carry power generated at Niagara Falls. Adam Beck, is named chairman.

1910

The first 110,000-volt electric power lines deliver electricity to municipalities in southwestern Ontario, starting with Kitchener (then known as Berlin).

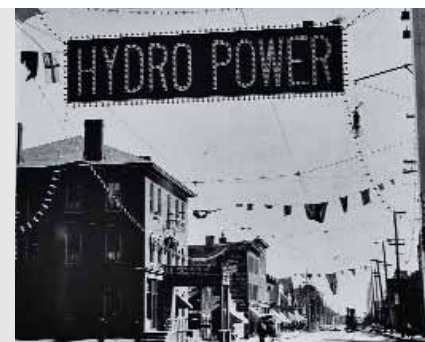
1912

The Beck Electric Circus tours the countryside showcasing the wonders of electricity.



Left: From the very early days, London was at the forefront in promoting hydro, as demonstrated by this photograph taken on the occasion of the Labour Parade in that city on September 1, 1913.

Right: This is a close-up of one of the displays that formed part of the colourful decorations in Kitchener on October 11, 1910, marking the first time power was switched on in that community.



1922

What would come to be known as the Sir Adam Beck 1 generation site on the Niagara River goes into service. At completion it's the largest generation facility in the world, requiring five times the excavation of the largest of the Great Pyramids.

Wiring Ontario for Delivery

Right: Workers at an early distribution station ready the wiring for commissioning. In the early days of building Ontario's electricity system, building and commissioning equipment was a major part of Ontario Hydro's work.

Making Connections

Below right: Leaside transformer station in Toronto is a major hub in our electricity delivery system. Transformer stations not only convert high-voltage electricity to lower voltages, they also expedite the delivery of electricity between stations.



building reliability

In the first 70 years of its existence, Ontario's electricity company focused as much on new construction to keep up with growing demand as it did on the actual business of generating and delivering electricity.

While we're solidly focused on operating and maintaining our transmission and distribution assets, we are now entering a phase that will bring much more new construction. In 2005, Hydro One invested more than \$700 million in upgrades, construction and maintenance for our transmission network. With the lengthy approval process for new construction, we are often working with our customers and industry partners to plan our work schedule years in advance.





Power People

Left and above: Highly skilled professionals, like Cathy Freskiw, are at the heart of Hydro One's system. Even though the equipment has changed a great deal, our commitment to delivering a reliable supply of electricity to the people of Ontario has not.

Taking Care of Distribution

In 2005, we increased our capital investments in our distribution system by \$50 million over 2004, from \$288 million to \$338 million.

This includes investment in new mechanical brushing equipment that will greatly enhance our ability to keep our distribution rights-of-way clear. Better brushing techniques will translate directly into improved service and productivity by decreasing the number of outages and allowing our crews easier access to remote equipment.

Pole replacement projects targeting communities across the province, from Kemptville to Moosonee, replaced 3,600 poles nearing the end of their service life. This work will continue in 2006 and beyond to ensure ongoing reliable supply to our approximately 1.3 million Hydro One distribution customers.

Niagara *Reinforcement* Project

In 1910, the power of Niagara Falls was first connected to Ontario's electricity consumers along the province's first transmission lines. Those first lines delivered more than electricity. They delivered a new way of living, working and doing business. They changed our world.

This year, we began a major upgrade of transmission facilities so that even more of the Falls' awesome power can reach Ontario's homes and businesses by the summer of 2006. Engineering and construction crews are taking down an old 115 kV line and replacing it with a new 230 kV double-circuit line across 76 kilometres. This project will allow us to deliver 800 MW more power – enough for 300,000 homes – from the Niagara Falls area to where it needs to be.

This project will also make new generation development possible in the Niagara Falls area, reduce the risk of supply shortages, allow for more efficient use of existing generation resources and reduce transmission line losses. It also improves Ontario's ability to import power from New York State when we need it. The start of construction in 2005 followed years of hard work on planning and approvals by employees across the Company. It has been included in our 10-year plan for several years. With the urgent need and the tight timeline, teams are working closely together to make sure the project stays on target. We are confident it will be delivered on time and on budget.

1930s

The Great Depression slows the demand for electricity.

1939

WAR! Ontario powers up to produce enough electricity to meet wartime production needs. Links with Quebec are established.



Left: Ontario Hydro linemen up the pole on June 11, 1947, were using hot line tools to work on "live" lines.

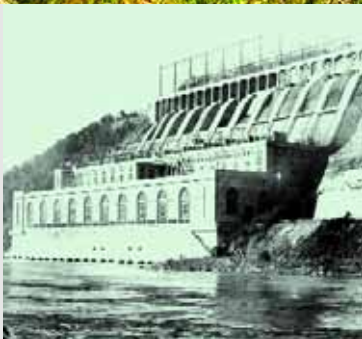


Left: Using single-horse power, these men made good progress in laying cable near Beamsville, Ontario, on November 22, 1923.



Growing Stronger

Above: Upgrading our system, like our Niagara Reinforcement project, is part of our core strategy for the years ahead. The Niagara project is expected to be completed by the summer of 2006 and will bolster our ability to deliver power from the Niagara region to southern Ontario.



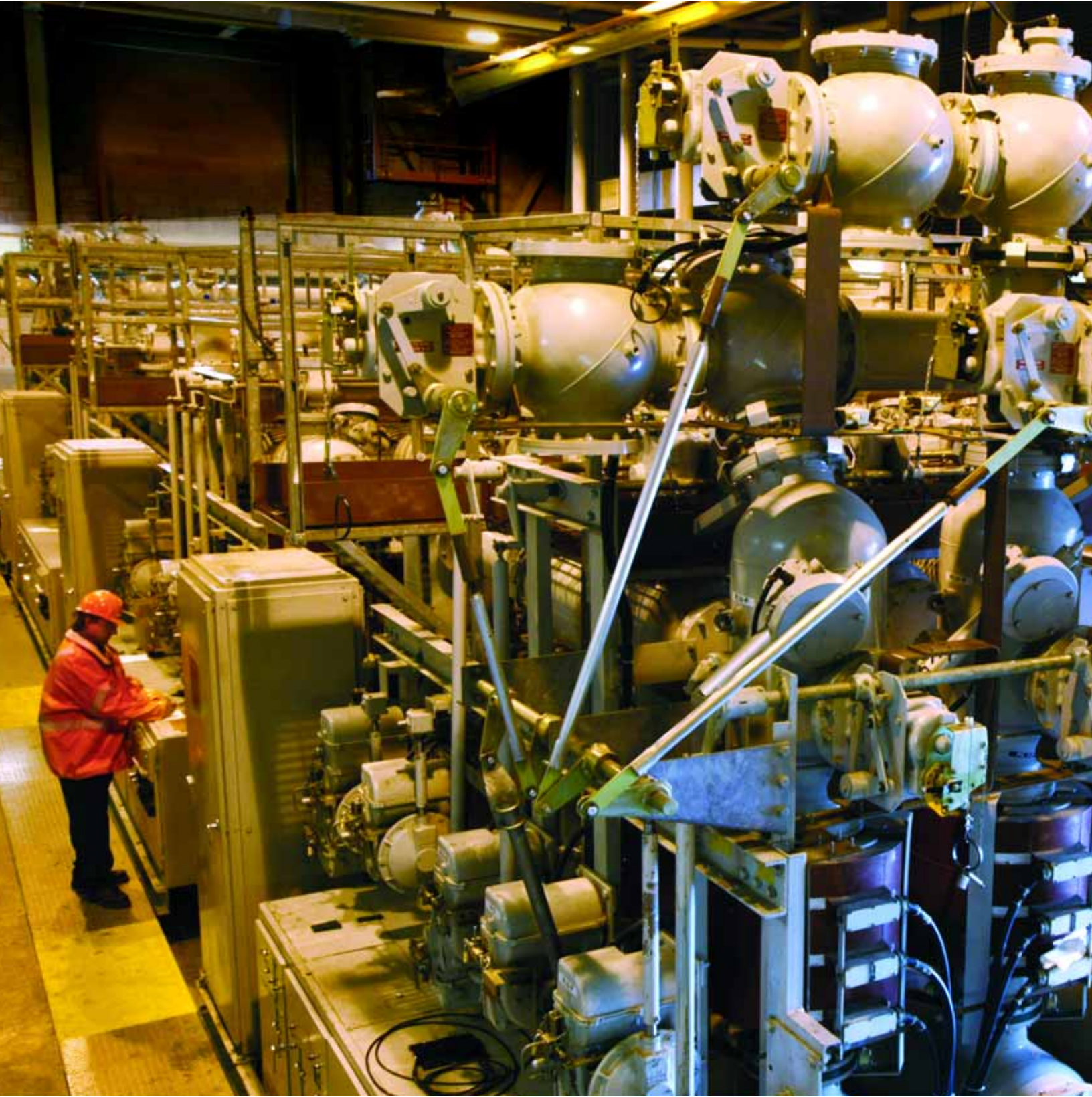
Left: The power of Ontario's waterways was the major source of electricity in the first half of the 20th Century.

1941

As part of the war effort, the first conservation program is started and customers are urged to "Save Hydro in Your Home: Help Win the War!"

1949 to mid 1950s

Power stations and transmission systems are centralized into one network for efficiency and flexibility. Ontario becomes compatible with the frequency of neighbouring provinces and states.





Vital Hub

Left: John Wright inspects equipment at the Cecil transformer station, a vital part of Hydro One's delivery system to downtown Toronto. Discreetly enclosed inside of a brick building, most people walking by wouldn't even notice the facility.

Feeding the System

Above: Water-powered generation plants like this one have been providing Ontarians with clean sources of electricity for more than a century.

Parkway transformer station

Parkway transformer station came into service in 2005, significantly strengthening the system supplying power to the GTA. It is part of our efforts to ensure power supply reliability to the GTA and to accommodate future growth. It strengthens the transmission system and supported the shutdown of the Lakeview generating station. The design, construction and start-up of this project on time and on budget is a tribute to the excellence of our employees.

Esplanade Cable Project

On March 11, 2005, the OEB approved our application to reinforce our electricity transmission facilities in downtown Toronto by constructing two new underground cable circuits between the John and Esplanade transformer stations. This project will reinforce existing infrastructure and allow us to deliver electricity to Toronto through a more flexible system. We began work in the fall, boring the tunnel beneath Toronto's subway system 30 metres underground connecting the two transformer stations, which are about 10 city blocks apart. We expect to have the cable in service in 2007.

forestry

Hydro One's lines traverse Ontario's roughest terrain. With 640,000 square kilometres of service territory we invest considerable time and effort to keep our lines clear of brush and trees. Downed trees and falling branches are a major cause of outages and keeping our lines clear improves reliability during stormy weather. In 2005, our forestry crews cleared 11,863 hectares of brush along our transmission corridors and 3,216 km of trees along transmission lines. We also cleared 9,076 km of our distribution lines.

In 2005 we moved further towards our target of returning our provincial clearing cycle on to a well-defined, seven-year clearing cycle for transmission lines and an eight-year clearing cycle for distribution lines. Carrying out our forestry program efficiently and consistently means fewer power outages caused by trees down on the lines.



Above: Forestry apprentices Jason Swant (front) and Frank Graves train in Cloyne, Ontario, to use Hydro One's advanced rigging system.

1950s

Hydro workers go door-to-door replacing more than 7 million appliance motors to match the new frequency.

1954-1958

The 1328-megawatt Sir Adam Beck 2 plant is built on the Niagara Gorge adjoining Sir Adam Beck 1.

1958

The 912-megawatt R.H. Saunders plant in Cornwall, Ontario is declared in service by Queen Elizabeth and American Vice-President Richard Nixon.



Left: This motor sled was used by a maintenance crew in the North Country in April 1942.



Left: Taken in 1943, this photo shows the transformer at the rear of the municipal office at Paris and a Hydro service truck.



Treetop Trimmers

Above: Hydro One foresters are highly trained to work on trees near live lines. Trimming and removing trees and brush helps prevent the inconvenience of power outages for our customers. Since 1999, we've reduced the number of outages by 10 per cent, largely through preventative measures like our forestry program.



Left: Before Ontario Hydro foresters could quickly rise to great heights in hydraulically operated buckets, they could rise to most occasions with the safety-tested equipment shown in this June 1947 photo.

1960

Construction of Canada's first 500,000-volt transmission line begins, connecting supply between northern Ontario and southern Ontario.



High Life

Left: Working on both our distribution and transmission system requires years of training and expertise.



working *safely*

In the last century, a quantum leap has been made in workplace safety. Early work on Ontario's electricity system exacted a significant human cost. From 1918 to 1928, the first decade of record keeping, 244 workers lost their lives building generating stations, stringing power lines and erecting towers. In the last decade, four workers died on the job working for Ontario Hydro's successor companies. Much of the credit for this dramatic improvement can be directly linked to the innovative ideas of the bright and dedicated employees of our company's predecessor. Today, the men and women of Hydro One proudly carry on that tradition. In recent years, we have introduced better work procedures, improved fall arrest equipment and techniques, arc-resistant clothing and advanced rigging techniques and improved design/equipment standards, to name a few.

While the evolution of safety is moving in the right direction, to Hydro One, zero is the only acceptable number. And we did not achieve it this year. On April 9, 2005, a Hydro One electrician was killed while working at our Cooksville transformer station. His loss is deeply felt and our sympathy goes out to his family.

While much has changed over the last 100 years, our primary hazards haven't. We work around and with electricity. We often work high above the ground. Annually, we log millions of kilometres driving on Ontario's highways and back roads, often in the worst weather conditions.

Front cover & page 20: Dan Butters



Left: This lineman was twisting absorber rods on cables when this picture was taken on January 18, 1932.

Airborne Line Maintainers

Left: Working on towers that are sometimes more than 200-feet tall either requires long hours of climbing or the expertise to step down from our AirStair device. The AirStair allows our helicopter to safely drop off and pick up line maintainers on top of our structures and was developed by Hydro One employees.

Know the Job

Right: From Left—Derrick Bridges, Mike Reid, John Bosomworth and Scott Punsit break down the job ahead. Before any work starts, each member of the team is briefed on the entire job and understands their role, the hazards and the role of everyone on the team.



On the Road

Left: Our crews spend countless hours driving and working alongside Ontario's roads. Driving and road safety training are a mandatory part of being on our team.



Our focus remains on achieving zero injuries caused by electrical incidents, falls and falling objects and those resulting from the operation of vehicles and equipment. Although we did not achieve our aspirational safety targets for 2005, we are closing the gap. The number of serious incidents was 12 per cent lower than 2004 and 28 per cent lower than 2003. Since 1999 our lost-time accident frequency rate has dropped by about half, putting us in the top quartile of Canadian transmission and distribution companies.

We continue to change our safety culture and infuse safety into every project and every decision, every day. From head office to the field, from Ottawa to Pigeon Lake, safety is our top priority and the entire company is committed to this goal.



Left: Stringing of transmission line on steel towers in the Niagara area is shown in this photo, dated February, 1910.

In Towers We Trust

Above: Line maintainers see our beautiful province from a perch like this one on a tower in the London area. Maintaining the transmission system requires inspection with thermal reading equipment from trucks and helicopters and then repairing weak spots in the system.

a workforce that *delivers*

By 2008, about a quarter of our workforce will be eligible for retirement. We are preparing for turnover in our workforce by actively identifying successors inside the company and drawing in new talent from outside. We are promoting careers in skilled trades and our recruitment efforts of university graduates are highly successful.

Hydro One is working with the Power Workers Union and our industry partners to recruit apprentices in lines and forestry so a skilled workforce is always there to take care of our system. We're also supporting co-op engineering programs at the University of Waterloo and other post-secondary institutions in Ontario.

Hydro One's labour relations strategy focuses on protecting shareholder value and providing for future economic stability for the Company. In 2005, we ratified collective agreements with

four different unions. We were unable to reach an agreement with The Society of Energy Professionals, resulting in a 15-week strike that ended with an arbitrated settlement. In the arbitration award, the company achieved two-tier pensions, one of its key bargaining objectives. The less provident pension plan applies to future hires into Society-represented positions and translates into a 25 per cent cost-savings compared with the existing pension plan. This is in line with the reduced pension plan instituted for management employees hired after January 1, 2004.

We remain focused on increasing operational flexibility and decreasing labour costs so we can continue to deliver electricity to Ontarians at a fair price.

1970

One synchronized, province-wide grid is created, with the exception of remote communities.

1971

Pickering nuclear generating station delivers nuclear powered electricity to Ontarians for the first time.

1977

The Bruce nuclear generating station comes into service.



Left: At the C.N.E. in 1936, Ontario Hydro "played up" the theme of "Better Light Better Sight."



Left: December 7, 1921. An early method of spooling out cable.

1989

The first unit of the Darlington nuclear generating station comes into service.



Left: Ontario Hydro's rural exhibit at the 1946 International Plowing Match at Port Albert.

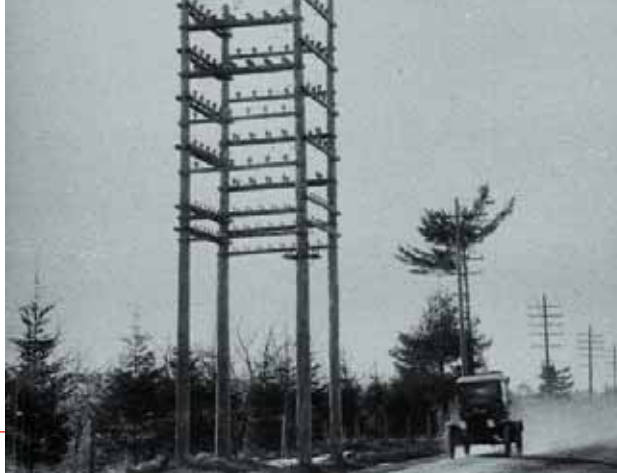
community and conservation

In the 1940s, Ontario Hydro asked Ontarians to conserve electricity to help with the war effort. In 2005, with demand almost outstripping supply and the system running at maximum capacity at peak hours, we're once again encouraging our customers to use electricity wisely.

With the cost of electricity rising, conservation has never been more important. Hydro One introduced several programs in 2005 to help Ontario communities cope with rising costs of electricity and reduce usage.

Low-income energy efficiency grant

Hydro One has teamed up with Canada Mortgage and Housing Corporation and Natural Resources Canada to provide financial incentives for energy-efficiency upgrades to low-income Hydro One customers who heat their homes with electricity. This is the first initiative of its kind in Canada, where three different organizations have come together to provide substantial benefits to homeowners who might not otherwise be able to afford upgrades. Under the Home Energy Efficiency Grant initiative, Hydro One is offering up to \$3,000 per qualifying household.



Above: Taken at Cooksville in March 1918, this photo shows what was known as a right angle structure.



Left: Community education at fairs and in schools is a vital part of Hydro One's corporate sponsorship program. We've dedicated \$20,000 in each of three years towards energy and electricity workshops through Scientists in Schools and we've also committed to \$150,000 over three years to expand the Advanced Coronary Treatment CPR programs in schools.

Below: Hydro One supports employees who volunteer with youth sports teams by providing sponsorship grants that make it easier for kids to get outside and play.



knowledge is *using less power*

Hydro One's engineers had a question. If people know how much electricity is costing them on a real-time basis, does it affect the way they use this valuable commodity? To answer this question, our staff conducted a year-long real-time monitoring pilot-program. One of the largest studies of its kind undertaken in Canada, 500 of our residential customers volunteered to have their meters fitted with sensors that captured real-time electricity usage and transmitted it to a small screen in the house. The screen showed exactly how much electricity was being used that month and what it was going to cost the family. They could see the projected monthly amount go lower when they turned off the air conditioner. They could see it go up when they switched on every appliance in the house. By knowing the dollars and cents of their daily usage, our customers used less. Compared to the previous year, the

pilot program families reduced their usage between 7 and 10%. Sometimes, knowledge means using less power.

Holiday LED exchange

Hydro One delivered holiday cheer in the form of energy savings to communities across Ontario by exchanging a new string of energy efficient Light Emitting Diode (LED) lights for two strings of old holiday lights. Using LEDs instead of traditional incandescent bulbs adds up to big energy savings over the holiday season. Compared to traditional lights, LEDs use up to 95% less energy, last at least 7 times longer, are more durable, with no filaments or glass bulbs to break and produce very little heat, reducing the risk of fire. Safe, smart and good value; now that's a great idea.

1997

We launch our first Web site, now called HydroOne.com.

1998

Heroic hydro workers toil in icy, freezing conditions to replace 10,750 poles, 1,800 transformers and 2,800 km of power lines destroyed by the Ice Storm.

1998

Ontario Hydro is broken up into five companies: Ontario Power Generation, Ontario Hydro Services Company, the IMO, OEFC and the ESA.



Left: Ontarians took great pride in the electricity delivery system in the 1950s and public tours of then "futuristic" control rooms were often in high demand.



Left: When the first nuclear plants were planned, Ontario Hydro spent a great deal of time on public information and education. When Hydro One embarks on a major project, community consultation is an important part of the plan.



Delivering Quality of Life

Left and above: Hydro One serves approximately 1.3 million distribution customers across Ontario. The electricity we deliver powers businesses, communities and families.

2000

Ontario Hydro Services Company is renamed Hydro One Inc.

2000 – 2002

Under a new legislative framework, Hydro One acquires 89 local distribution companies, increasing its customer base by 25 per cent to 1.2 million.

2002

Hydro One's Charity Trust program raises \$650,000 for Ontario charities.

2003

A tree on a transmission line in Ohio causes a power outage that affects the entire Eastern Seaboard of North America. Hydro One crews worked rapidly to be able to deliver all available power within 24 hours.



Founding Father of Power in Ontario

Sir Adam Beck was a prosperous London, Ontario, manufacturer, who was simultaneously the Mayor of London and a member of the provincial legislature. Beck was an early champion of public power and lobbied hard to have the hydro-electric power resources at Niagara connected to communities across Ontario. In 1906, Beck became "Power Minister" and chairman of the Hydro-Electric Power Commission of Ontario, the world's first publicly-owned utility.

His initial project was to build a 110,000-volt transmission line from Niagara Falls to carry power to southwestern Ontario municipalities, including Toronto and 13 other communities. On October 11, 1910, Beck held his first ceremonial "switch-on" in Berlin (now Kitchener) to celebrate the completion of this line. When he pressed a switch and lit a street sign that read "For the People", the town went wild.

Before he died in 1925, Beck was instrumental in developing the 450-megawatt Queenston Chippawa power station at Niagara Falls. When it was commissioned, it was the largest power station in the world. In 1950, this station was renamed Sir Adam Beck I to honour his memory.



Above: Two units of the Adam Beck "Circus," which carried various appliances to the farms of Ontario to provide on-the-spot demonstrations, can be seen in the background of this photo taken in 1912. When they saw how easy it was to saw wood with Hydro, fewer and fewer farmers had axes to grind.

— Review of Operations —

2004

Hydro One opens the Ontario Grid Control Centre, centralizing operation of the province's transmission and distribution centre in one facility.

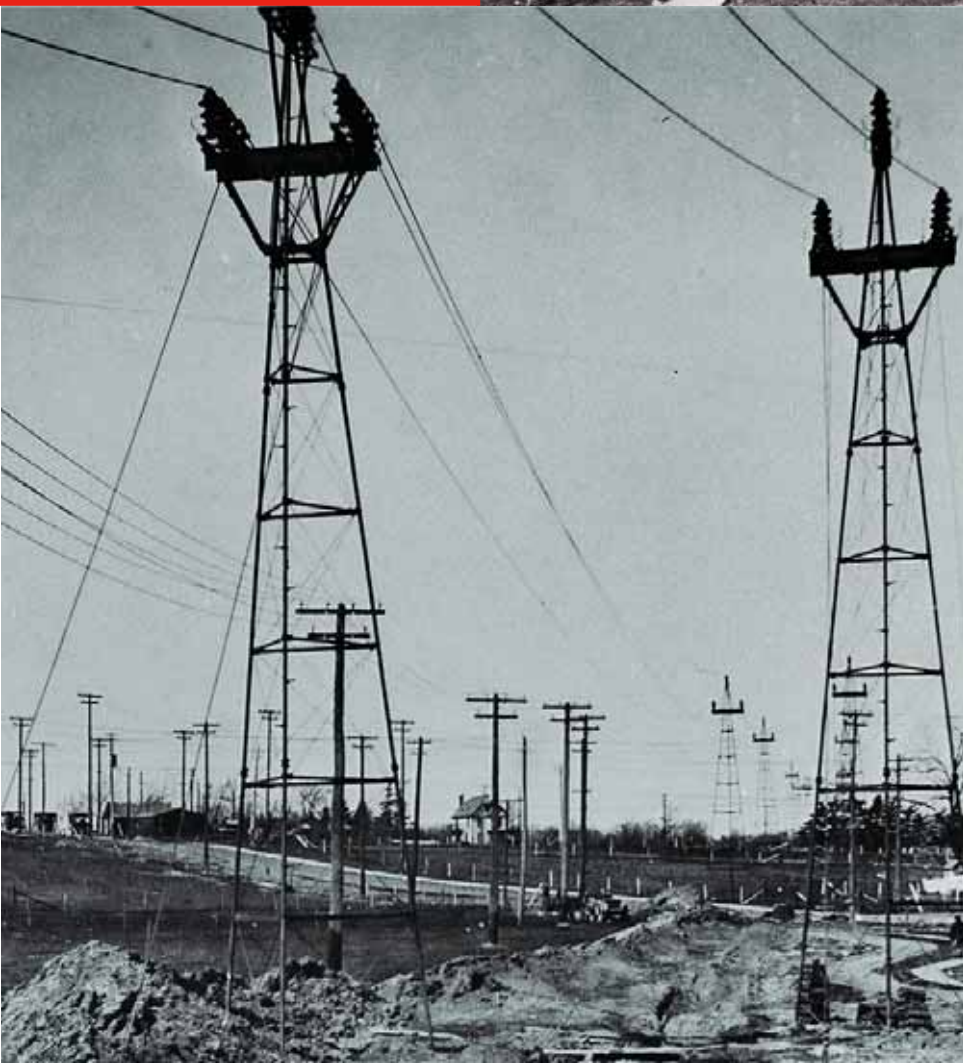
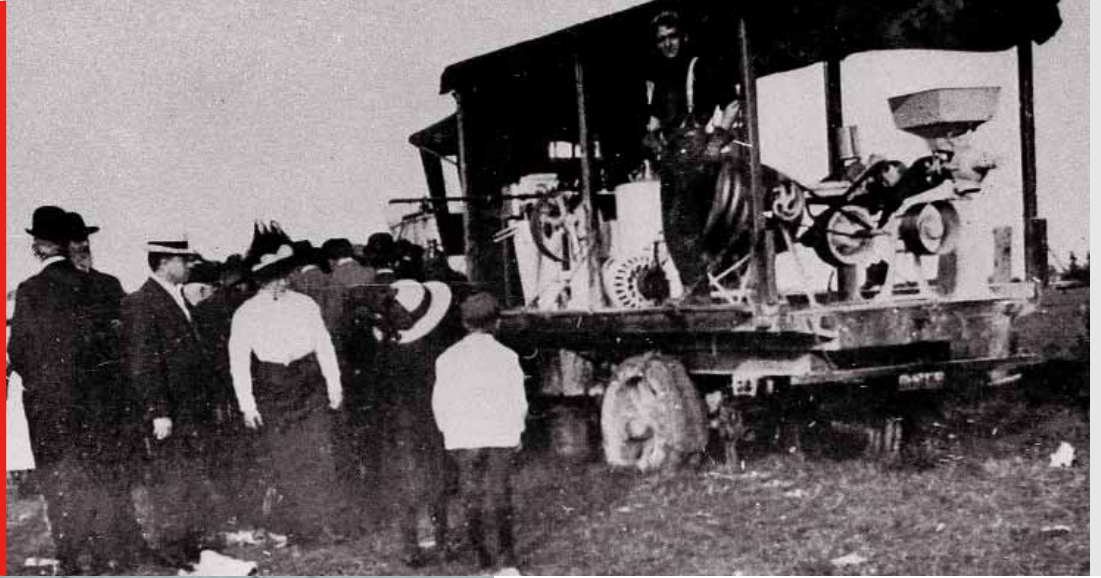
2005

Work is completed on the Parkway transformer station to improve supply reliability and enable the shutdown of the coal-fired Lakeview generating station.

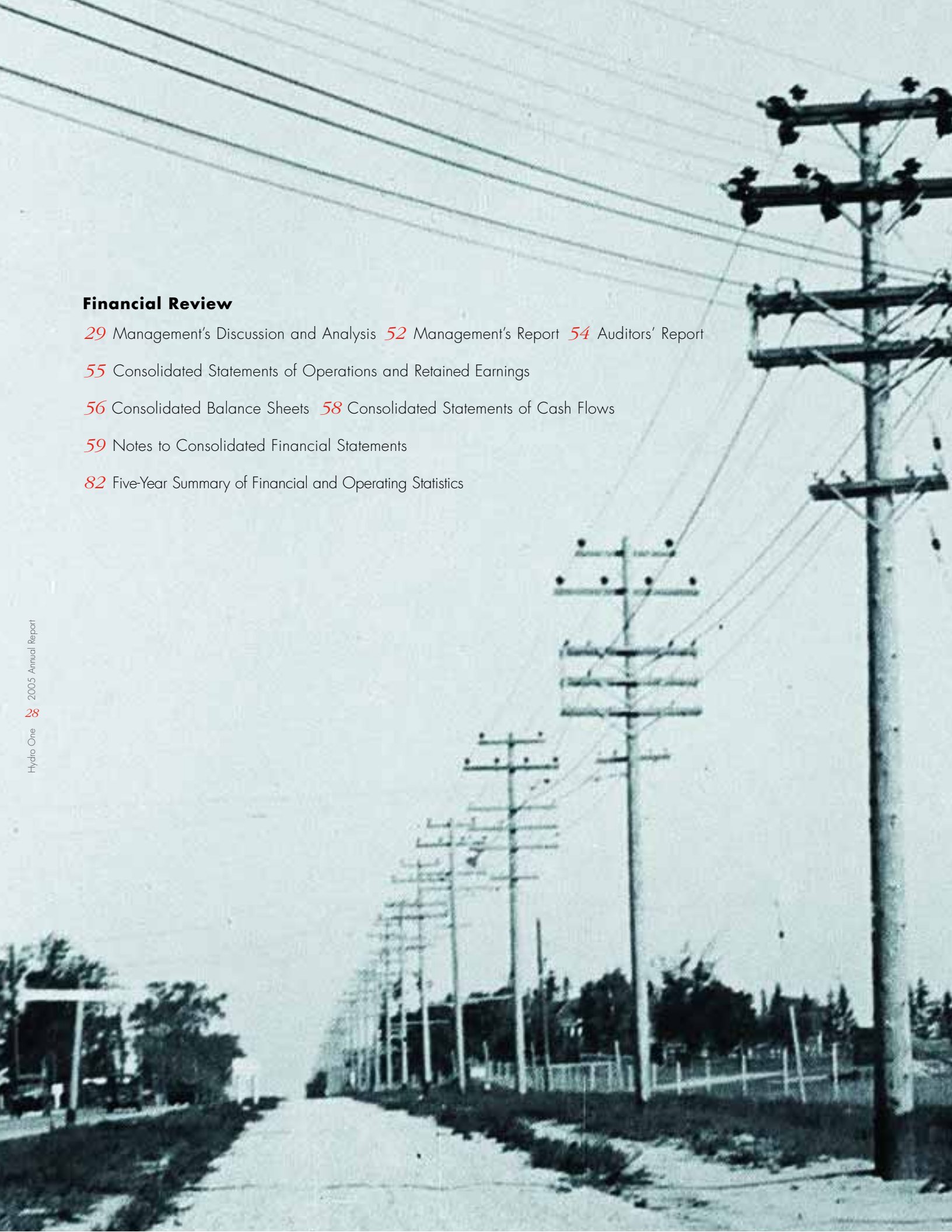
Present Day

As it was a century ago, it is today. The government of Ontario fully owns Hydro One, one of North America's largest transmission and distribution companies with almost 30,000 km of transmission lines, and approximately 1.3 million distribution customers.

Right: When the Adam Beck Circus was on the move, crowds would gather at its stops to see the latest electrically powered equipment.



Left: The earliest steel towers and high-voltage lines were quite a different shape than the one's we use today. This photo was taken in 1910, near Niagara Falls.



Financial Review

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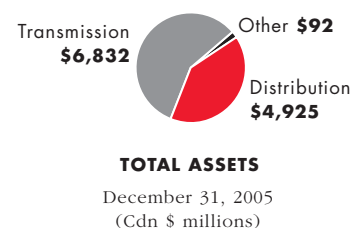
We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2005 and 2004.

OVERVIEW

We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario. Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2005, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

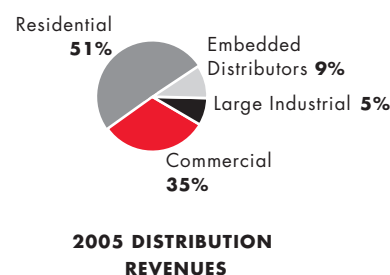
Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2005, we earned total transmission revenues of \$1,310 million primarily by transmitting approximately 157 TWhs of electricity, directly or indirectly, to more than 4 million customers. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MWs and exports of approximately 5,800 MWs of electricity. In terms of assets, our transmission business is our largest segment, representing more than 50% of our total assets.



Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, approximately half of our distribution revenues are earned from our residential customers.



Other

Our other business segment contributed revenues of \$21 million in 2005 and has assets of about \$92 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. We are currently in the process of assessing our strategy with respect to these operations.

OVERVIEW (continued)

Our Strategy

In 2005, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value. We seek to achieve these goals by continuing our focus on the following strategies:

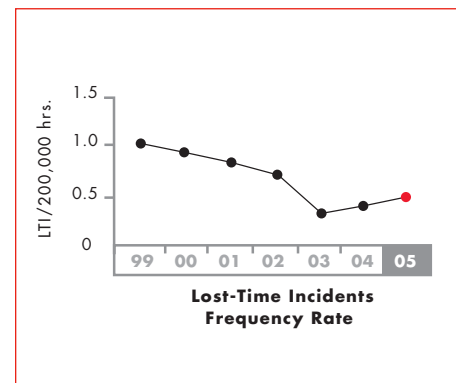
- *Safety*: Create and maintain an injury-free workplace with a concentrated focus on prevention of serious injury.
- *Customer Service*: Become a leading customer-focused company. We will undertake initiatives and deliver on actions in a timely manner to improve our customers' level of satisfaction. In particular, we will strive to build positive relationships with all of our customer segments, acknowledging the commercial requirements of our large and mid-sized customers.
- *Reliability*: Enhance the reliability of our transmission and distribution systems while continuing to develop and expand the transmission system to meet Ontario's future needs.
- *Financial*: Ensure our actions contribute towards maximizing the value of our company, while maintaining an effective borrowing capability through stable credit quality and delivering appropriate financial returns to our shareholder.

Performance Measures and Targets

We measure and target our performance in all the above strategic areas. We largely met our challenging 2005 objectives, improving in a number of areas over 2004 levels, and are moving forward to meet our strategic goals.

As we work in an environment with significant hazards, safety is our top priority. In 2005, we experienced an employee fatality at a transformer station. This unfortunate occurrence is a painful reminder of the workplace hazards that we deal with on a daily basis. Consequently, our focus remains on the goal of achieving zero injuries by 2006 for categories such as electrical incidents, falls and motor vehicle accidents where there is a high potential for serious injury. The number of serious lost time injuries has consistently remained at four per year over the last number of years. Although we did not achieve our aggressive safety targets for the year, the number of serious incidents in 2005 was 12% lower than 2004 and 28% lower than 2003.

As shown in the accompanying chart, since 1999 our lost-time incident frequency rate has dropped by about 50%, placing us in the top quartile of Canadian transmission and distribution companies. The majority of our 2005 lost-time incidents were related to minor injuries such as strains and slips. Going forward, we will continue to emphasize the importance of safety, with the goal of further improving our safety performance. This involves a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned safety initiatives include an injury and exertion prevention program, a coaching and mentoring program, developmental rotations, and a fleet safety program.



By addressing service issues, focusing on key areas of importance for our customers and upgrading our assets, we have made tangible improvements in customer satisfaction. We met all OEB targets for customer service. As shown in the accompanying chart, the level of satisfaction of our large transmission and local distribution company (LDC) customers improved by 14% over 2004 levels and 57% over 2003 results. Residential customer satisfaction levels remained consistently strong at 82%. Building on this momentum, we will continue to focus on improving the level of satisfaction of all our customers by undertaking initiatives which will streamline their points of contact and reduce our response time to customer requests.



We achieved all of our OEB targets for frequency and duration of interruptions. In particular, our transmission system reliability for frequency of interruptions out-performed our 2005 target and our 3-year average. The average duration of interruptions was within OEB targets, although slightly higher than the 3-year average (2002-2004), as a result of a late April freezing rainstorm in Southwestern Ontario and two outages on a remote line with limited accessibility. We continue to focus on the reliability of our distribution system. However reliability improvements are more challenging due to the rural nature of our system. Considering the impact of severe storms, we met our distribution reliability target for frequency and duration of interruptions and maintained the previous 3-year average (2002-2004). A number of key initiatives were undertaken during the year to enhance our performance, including improved crew scheduling to allow faster restoration response to unplanned outages. We also carried out detailed line reliability and customer impact analysis for use in developing investment requirements.

Strong financial performance again characterized our 2005 results and we maintained or improved our credit ratings on both our short and long-term debt.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates in proceedings through oral or written public hearings. These rates are based on the required level of revenue that the OEB allows for us to operate our regulated businesses, plus an approved rate of return.

Our industry has undergone significant restructuring over the past several years. On May 1, 2002, Ontario's wholesale and retail electricity markets were opened to competition (Open Access). Under Open Access, most consumers paid the wholesale spot market price for electricity as determined by demand and supply in the wholesale spot market administered by the Independent Electricity System Operator (IESO). In response to price volatility, the *Electricity Pricing, Conservation and Supply Act, 2002* was enacted to cap transmission and distribution rates and to fix the commodity price of electricity at 4.3 cents per kWh for low-volume and designated consumers.

As a result of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, the transmission and distribution rate caps were lifted. The fixed commodity price was replaced with a two-tiered pricing structure, effective April 1, 2004. Under this structure, low-volume and designated consumers paid 4.7 cents per kWh for the first 750 kWh of electricity consumed each month and 5.5 cents per kWh for electricity consumed over this threshold each month.

REGULATION (continued)

On December 9, 2004, the Ontario Legislature passed the *Electricity Restructuring Act, 2004* to provide consumers with stable prices that better reflect the true cost of electricity, facilitate new supply, and promote conservation and demand management. The act also created the Ontario Power Authority (OPA), which has a mandate to ensure an adequate, long-term supply of electricity in Ontario. The IESO continues to be responsible for overseeing and running the wholesale markets and ensuring the reliability of the integrated power system.

Under the new market structure, wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices for electricity. At the retail level, the OEB approved a Regulated Price Plan (RPP) for certain low-volume and designated consumers. The RPP maintained a two-tiered pricing structure, set new commodity prices, and introduced seasonal consumption thresholds for residential customers. The commodity price was based on an OEB forecast of the price of electricity over the period from April 1, 2005 to March 31, 2006 and was set at 5.0 cents per kWh for the lower tier and 5.8 cents per kWh for the upper tier. The consumption thresholds for residential customers were 750 kWh for the 2005 summer months (April 1 to October 31) and 1,000 kWh for the winter months (November 1 to April 30). For the 2006 summer months (May 1 to October 31), the threshold for residential customers will be 600 kWh. For all other RPP customers, the consumption threshold is 750 kWh year-round. The OEB intends to review these prices semi-annually starting May 1, 2006. The price plan also introduced time-of-use pricing for those customers with smart meters. Unexpected shortfalls or overpayments will be administered by the OPA and passed through to customers over the course of a year, starting on a price resetting date. As a result, our distribution business does not have commodity price risk.

On November 3, 2005, the Government of Ontario (Government) introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by 2007, with installation in all homes and businesses to be completed by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. LDCs, including our distribution businesses owned and operated by our wholly-owned subsidiaries Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton), will own, install, operate and maintain the meters.

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. Existing rates were set based on cost of service rate regulation. The OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity, which in the last rate-setting period was targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB will consider options to track net income excesses or deficiencies from OEB-approved returns for the period from January 1, 2006 until the revised transmission rates are implemented. The options identified by the OEB include the possible use of a regulatory deferral account or an earnings-sharing mechanism.

On November 23, 2005, we submitted a proposal to the OEB that any excess earnings be returned to customers in the form of transmission system expansion projects that are critical to the economic health of Ontario and to the secure operation of the system. The approval of any earnings sharing mechanism could have a significant impact on our net income. We participated in an oral hearing on this matter and we anticipate a decision from the OEB in the first quarter of 2006. We also anticipate submitting evidence this summer in preparation for a transmission rate hearing expected to be held this fall. A 1% change in the return on deemed common equity of the transmission business, would affect our net income by about \$22 million.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue will decrease by approximately \$13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates are approved by the OEB, based on a revenue requirement that includes a rate of return. Our distribution rates continue to be set based on cost of service rate regulation. Our current rates include a targeted return of 9.88% on deemed common equity. In August 2005, we filed a distribution rate application seeking approval for a \$160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. If approved, customers would see an average increase of 6% on their monthly bills starting in May 2006. This rate application is currently in the evidentiary phase. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006.

In December 2004, we received OEB approval to recover certain distribution-related deferral account balances, over the period ending April 30, 2008. The recovery of these prudently incurred costs was originally suspended by the *Electricity Pricing, Conservation and Supply Act, 2002*. These deferred amounts primarily include charges for low-voltage services to embedded LDCs and direct customers, market-ready transition costs, retail settlement variance account balances, and certain environmental costs. In March 2005, the OEB also approved our application to implement the final installment of a rate increase associated with moving toward our allowable return on equity that was originally to be effective for all LDCs on March 1, 2003. Our distribution rates were increased on April 1, 2005 to reflect these decisions.

We also filed a distribution rate application seeking approval for a \$3 million increase in the 2006 distribution revenue requirement of Hydro One Brampton, which would result in customers seeing an average increase of 1% on their monthly bills starting in May 2006. This rate application is subject to a separate OEB process, independent of the Hydro One Networks' distribution application.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	2005	2004	\$ Change	% Change
Transmission	1,310	1,262	48	4
Distribution	3,085	2,874	211	7
Other	21	17	4	24
	4,416	4,153	263	6
Average annual Ontario 60-minute peak demand (MW) ¹	23,074	22,375	699	3
Distribution – units distributed to customers (TWh) ¹	29.7	28.5	1.2	4

¹ System related statistics include preliminary figures for December.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover the necessary revenues to support a transmission system that has sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

The increase in transmission revenues in 2005 primarily reflects the extreme weather conditions experienced during the summer of 2005, which was one of the hottest on record. Temperatures in excess of 30°C were common, resulting in the previous record for electricity consumption of 25,414 MW being exceeded on seven occasions. In July, the new record peak demand was set at 26,160 MW. Only the summers of 2002 and 1998 have been comparable since 1970. Peak demand increases, compared to 2004, were also experienced in some of the remaining months of the year. Ancillary transmission revenues were marginally lower this year.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include minor amounts of ancillary distribution services revenues, such as fees for the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased in 2005 compared to last year mainly due to the recovery of higher purchased power costs of \$144 million, as described below under “Purchased Power.” The remaining increase primarily reflects an OEB-approved distribution tariff rate increase effective April 1, 2005, the recognition of low-voltage services revenues, and increased demand. The approved tariff increase was originally scheduled to be effective March 1, 2003, but was subsequently suspended for all LDCs by the *Electricity Pricing, Conservation and Supply Act, 2002*. During 2004, the low-voltage services revenues were deferred until a December 2004 prudence decision by the OEB allowed for regulatory recovery starting in 2005. Ancillary distribution revenues were lower this year primarily due to a lower level of assistance required by Florida Power and Light Company to repair hurricane damage in 2005. In 2004, our crews were called upon twice to provide hurricane recovery assistance, compared to once in 2005. Such assistance is carried out under a North American mutual-assistance agreement.

Under a new regulation issued in October 2005, RPP customers received the *Ontario Price Credit*, reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter, revenue and cost of power were both reduced by approximately \$140 million, representing the amount refunded to customers. The application of the *Ontario Price Credit* did not result in any adjustment to net income in the current period or in previously reported periods.

Other

Other revenues were higher by \$4 million compared to 2004 due to increased lit fibre revenues within our telecommunications business.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. Prior to April 1, 2004, for certain low-volume and designated customers, the commodity price of electricity was fixed at 4.3 cents per kWh. On April 1, 2004, this fixed rate was replaced by an interim two-tiered pricing structure of 4.7 cents per kWh for the first 750 kWh consumed each month and 5.5 cents per kWh for electricity consumed over this threshold each month. On April 1, 2005, the interim pricing structure was replaced by the OEB's RPP which consists of a two-tiered pricing structure of 5.0 cents per kWh for the first 750 kWh consumed each month and 5.8 cents per kWh for any additional consumption. Effective November 1, 2005, the first 750 kWh threshold was increased to 1,000 kWh during the winter months for residential customers. Customers who are not eligible for the RPP continue to pay market prices for electricity, adjusted for the difference between market price and regulated and contract prices paid to generators under the *Electricity Restructuring Act, 2004*.

Purchased power costs increased by \$144 million, or 7%, to \$2,131 million in 2005 compared to last year. This increase primarily reflects higher demand of \$84 million and higher commodity prices of approximately \$60 million. Commodity prices reflect higher wholesale prices for customers who are not eligible for the RPP, partially offset by lower net prices for RPP customers. The increased commodity prices due to the implementation of the April 2004 and April 2005 pricing structures for RPP customers, were more than offset by the mandated *Ontario Price Credit* associated with lower commodity prices between April 1, 2004 and March 31, 2005 as described above under "Distribution Revenues."

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004	\$ Change	% Change
Transmission	353	356	(3)	(1)
Distribution	413	392	21	5
Other	26	23	3	13
	792	771	21	3

RESULTS OF OPERATIONS (continued)

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way were marginally lower than in 2004. Overall we maintained our necessary work program levels consistent with our safety and reliability standards at our transmission sites. We did experience lower station maintenance costs across our system as conditions, primarily caused by the abnormally high temperatures during the summer months, constrained our ability to take our equipment out of service for maintenance. As a result, additional maintenance is expected to be required in future periods. The reduction in these work program expenditures was substantially offset by higher expenditures from increased brush and line clearing activities, higher preventive maintenance on certain of our facilities and higher costs related to the reassignment of resources to support maintenance activities due to the smaller transmission capital program this year. Other cost reductions resulted from a labour disruption and from cost recoveries associated with insurance settlements and bad debts.

Distribution

Operation, maintenance and administration expenditures required by our distribution business to serve communities across Ontario were \$21 million higher than last year. We maintained an enhanced forestry work program on our province-wide rights-of-way to improve reliability by reducing our trimming cycles. We also incurred increased expenditures to restore power due to intense storm activity this year. As required by the OEB, we also initiated our conservation and demand management programs in support of developing a conservation culture. These overall cost increases were partially offset by lower costs resulting from a labour disruption and lower costs required to provide emergency hurricane relief to Florida Power and Light Company.

Other

Other operation, maintenance and administration costs were \$3 million higher this year compared to 2004. This result reflects the higher level of lit fibre service revenues.

Depreciation and Amortization

Depreciation and amortization expense for 2005 increased by \$7 million, or 1%, to \$487 million relative to the comparative period. This change primarily results from increased fixed asset removal costs, including such costs attributable to our Niagara Reinforcement Project which started in the last quarter of 2005.

Financing Charges

Financing charges decreased by \$6 million, or 2%, to \$325 million compared to last year. The reduction was due to the effect of higher interest capitalization on our regulatory assets associated with the OEB's December 9, 2004 rate decision, partially offset by the impact of higher average debt levels.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by \$21 million, or 12%, to \$198 million compared to 2004. A higher tax provision on higher income this year was partially offset by the recognition of a tax benefit of approximately \$21 million relating to accumulated tax losses of a subsidiary. The tax benefit was recognized during the second quarter of 2005 after an agreement was reached to settle an outstanding legal claim that allowed for the dissolution of the subsidiary.

Net Income

Net income in 2005 increased \$76 million, or 19%, to \$483 million compared to 2004, excluding the impact of last year's one-time regulatory recovery. This increase primarily reflects higher tariff revenues within our transmission and distribution businesses. We maintained an intense focus on the operation of our equipment during the abnormally hot summer to ensure continuous, reliable delivery of electricity to Ontarians. In addition, we experienced a favourable impact on our results due to the recognition of a tax benefit related to the accumulated tax losses of one of our subsidiaries. These impacts were partially offset by higher operations, maintenance and administration expenditures, primarily within our province-wide distribution business. Including last year's one-time regulatory recovery, which was caused by the suspension of an approved rate increase under the *Electricity Pricing, Conservation and Supply Act, 2002*, our net income decreased by \$15 million, or 3%, compared to 2004.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2004 through December 31, 2005. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2005				2004			
Quarter ended	Dec. 31	Sep. 30	Jun. 30	Mar. 31	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues ^{1, 2, 3}	1,025	1,179	1,018	1,194	1,074	1,018	960	1,101
Net income ^{1, 2, 3, 4}	104	133	115	131	186	133	59	120
Net income to common shareholder ^{1, 2, 3, 4}	99	129	110	127	181	129	55	115

¹ Both the revenue and the net income amounts reported in the first and second quarter of 2004 have been reduced by \$5 million and \$6 million, respectively, to reflect a change in interperiod allocations.

² The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

³ Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately \$140 million. The application of the one-time credit did not result in any adjustment to net income in the current period or previously reported periods.

⁴ As a result of submitted oral and written evidence, on December 9, 2004 the OEB issued a ruling citing prudence and approving recovery of amounts, previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought in our May 31, 2004 submission. Consequently, net income for the fourth quarter of 2004 includes a regulatory recovery of \$91 million.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	2005	2004
Operating activities	1,170	911
Investing activities		
Capital expenditures	(691)	(727)
Financing activities		
Long-term debt issued	500	540
Long-term debt retired	(648)	(472)
Short-term notes payable	(40)	15
Dividends paid	(291)	(265)
Other financing and investing activities	—	26
Net change in cash and cash equivalents	—	28

Operating Activities

Net cash generated from operations increased by \$259 million compared to 2004. This increase is primarily attributable to lower working capital requirements and a higher level of net income this year, excluding last year's one-time non-cash regulatory recovery. Our working capital requirements have primarily been affected by funding received from the IESO to process the mandated credit for RPP customers. This funding had a positive impact on working capital due to the timing of customer billing cycles. In addition, changes in our trade accounts payable balances reflecting our work program and the timing of tax payments contributed to the reduction in our working capital requirements.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to \$1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a \$750 million committed revolving credit facility with a syndicate of banks which matures in August 2006 and has a two-year extension option. As at December 31, 2005, we had no short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2006 and 2043. We currently plan to refinance maturing debt principally through our medium-term note program, which was renewed in June 2005. The maximum authorized principal amount of medium-term notes issuable under this program is \$2,500 million, of which the full amount is remaining and is currently available until July 2007.

Rating Agency	Rating	
	Short-term Debt	Long-term Debt
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (low)	A
Moody's Investors Service Inc.	Prime-1	Aa3

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement that supports our \$750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. As at December 31, 2005, we were in compliance with all of these covenants and limitations.

During 2005, we issued \$500 million in long-term debt prior to the renewal of our medium-term note program and we repaid \$648 million in maturing long-term debt. In comparison, during 2004 we issued \$540 million in debt under our medium-term note program and we repaid \$472 million in maturing long-term debt. In 2005, we decreased our short-term notes by \$40 million compared to an increase of \$15 million in 2004.

In 2005, we paid dividends to the Province in the amount of \$291 million, consisting of \$273 million in common dividends and \$18 million in preferred dividends. In the comparative period, we paid common dividends of \$247 million and preferred dividends of \$18 million.

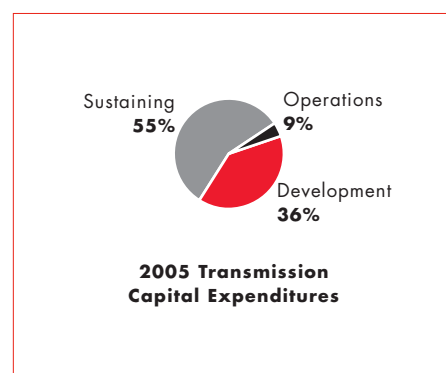
Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004	\$ Change	% Change
Transmission	349	432	(83)	(19)
Distribution	338	288	50	17
Other	4	7	(3)	(43)
	691	727	(36)	(5)

Transmission

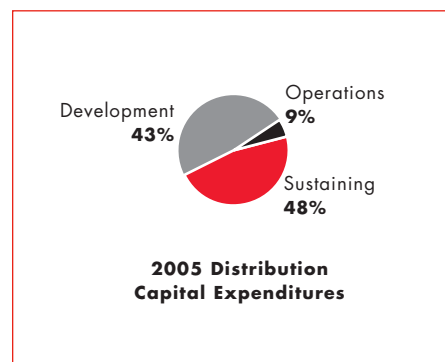
Transmission capital expenditures were \$349 million and \$432 million in 2005 and 2004, respectively. Capital expenditures to expand and reinforce our transmission system decreased by \$98 million to \$125 million, primarily due to the completion of the Parkway transformer station this year. This project was initiated last year in response to growing loads and the closure of the Lakeview generating station. In 2004, we also completed our Ontario Grid Control Centre, enabling us to access cost efficiencies and allowing for improved customer response and advanced monitoring and analysis of our system. Late in the current year, we began construction of our Niagara Reinforcement Project. This critical infrastructure project includes a new transmission line which will alleviate transmission constraints in the Niagara region and allow additional clean energy from Niagara Falls and electricity imports to reach consumers. Cost recovery will be subject to the provision of evidence regarding the economic benefits of this project. Capital expenditures incurred to sustain our transmission lines and stations, and to maintain reliability, increased by \$17 million to \$193 million, reflecting refurbishment and minor component replacement projects which did not require our equipment to be taken out of service. However, due to constraints, such as the effect of an abnormally hot summer, we did not fully complete our planned sustainment program this year and we anticipate completing such projects in future periods. Our other capital expenditures decreased marginally by \$2 million to \$31 million.



LIQUIDITY AND CAPITAL RESOURCES (continued)

Distribution

Distribution capital expenditures were \$338 million in 2005 compared to \$288 million in 2004. Capital expenditures to sustain our distribution system increased by \$46 million to \$162 million, primarily due to increased investments related to storm damage recovery and transport and work equipment, including new brushing equipment expected to further enhance productivity within our forestry program. In addition, other capital expenditures to support our distribution network increased by \$14 million to \$29 million, primarily as a result of increased investments in information technology assets. Capital expenditures to expand and reinforce the low-voltage distribution system declined by \$10 million to \$147 million. This reduction reflects the reprioritization of work during the labour disruption, partially offset by increased demand for new connections.

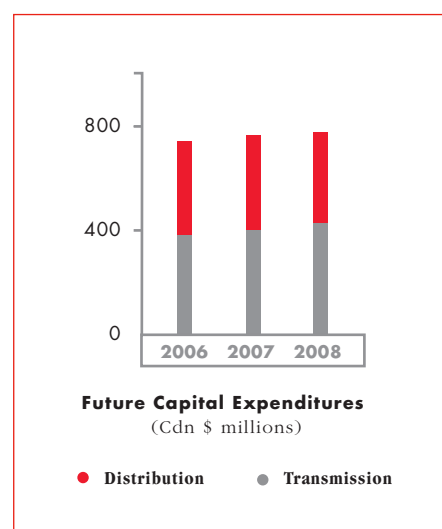


Other

Other capital expenditures decreased by \$3 million to \$4 million. The level of expenditures reflects the timing of projects to meet customer demand for new services.

Future Capital Expenditures

Our capital expenditures in 2006 are budgeted at about \$755 million, an increase of approximately \$65 million over 2005 actual levels but consistent with 2005 budgeted levels. Capital expenditures for 2005 were lower than budget due to constrained outage availability resulting from the hot summer, as well as the impact of a labour disruption and our efforts to focus on delivering the capital projects with the highest priority. The 2006 capital budgets for our transmission and distribution businesses are about \$390 million and \$360 million, respectively. Other capital expenditures are budgeted at \$5 million and are largely minor enhancements to our fibre-optic network in support of our telecommunications business. Capital expenditures, as shown in the accompanying chart, are expected to increase marginally over the next few years, primarily reflecting investments in transmission infrastructure. There is also the potential for large-scale transmission infrastructure projects and conservation initiatives not included within our current investment plan due to the level of uncertainty, complexity and cost. These potential investments, together with our planned capital expenditures program, are discussed below.



Transmission

Transmission system capital expenditures are expected to increase marginally over the period 2006 to 2008. Given continuing supply constraints, we will focus on critical transmission assets that support generation facilities, such as our 500kV lines and high-voltage switch yards. The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Key transmission investment areas are power equipment, protection and control equipment, ancillary systems and overhead and underground lines.

In addition, increased expenditure levels reflect transmission development work identified in our 10-year transmission plan, *Transmission Solutions 2005-2014*. These investments ensure that growing area supply needs, reliability requirements, and needs for increased access to the Ontario market are successfully met. A number of specific development initiatives are nearing completion or are well underway, including the Niagara Reinforcement Project and the construction of underground transmission cables to improve reliability in downtown Toronto.

At the local level, we continue to proactively address supply needs with our customers. For projects required to provide reliable supply to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes continues to be essential for maintaining the safe and reliable delivery of electricity. Examples of projects initiated to meet the growing needs of our customers include: Holland transformer station to serve northern York Region; Belle River transformer station to serve areas in Essex County; and Everett transformer station to serve southern Simcoe County. In addition, we are in discussions with a number of customers in the areas of Kingston, Durham Region, Burlington, and in a number of communities in Western and Northwestern Ontario.

The timing of many of these projects and others is uncertain as they are dependent upon need and, in some instances, require approvals by various regulatory bodies, as well as negotiations with customers, neighbouring utilities and other stakeholders. In addition, the OPA is expected to file an Integrated Power System Plan (IPSP) with the OEB during the summer of 2006. The IPSP will detail how Ontario's medium and long-term electricity needs will be met, consistent with the public interest. Using our 10-year transmission plan as a basis, we continue to work closely with the OPA on transmission solutions to address these needs.

The IPSP could include additional large-scale projects which are not currently included in our investment plan. These major initiatives may be necessary to increase the supply of electricity and to support the closure of coal-fired generation. We are actively participating in various working groups involving key government and electricity industry stakeholders in this respect. In particular, we continue to develop interconnection enhancement possibilities with our neighbouring utilities, including those required to support the Government's existing and future power purchase agreements with the Province of Manitoba which could increase transmission capacity by up to 1500 MW. Planning also continues on a number of other major initiatives, including the development of a major new supply line between Central and Western Ontario to accommodate new power developments and enable the shutdown of the Nanticoke coal-fired generation station. As well, planning continues on the development of a major new supply line to Toronto to enhance reliability. We would not undertake these large complex projects without a reasonable expectation that such expenditures would be recoverable in our rates.

Distribution

We continue to replace and improve our aging distribution asset base in order to improve system reliability. Increasing investments will be made within the distribution business, in particular reflecting increased wood pole replacements, feeder sectionalization and defect management. Across Ontario, we are continuing the replacement of older distribution systems with higher voltage and more current-standard installations. In addition, we are constructing new lines and stations in response to system growth forecasts or high load relief requirements, and will focus our efforts on making the distribution system more efficient. Examples of some of these initiatives include a new station to serve northern King Township and various projects to reduce losses on our distribution system.

LIQUIDITY AND CAPITAL RESOURCES (continued)

In addition, we are moving forward with initiatives to improve the reliability performance of our distribution system. Cost-effective improvements can be achieved by enhancing maintenance practices and the operability of the system by continuing to add sectionalizing capability at selected locations to reduce the number of customers affected by system outages. We will continue to implement a range of conservation and demand management programs consistent with our OEB-approved program.

In November, 2005, the Government introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be complete by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. LDCs will own, install, operate and maintain the meters and continue to bill their customers. This program is expected to increase our expenditure levels and reduce our tariff revenues. It is estimated that our costs could range from \$600 million to \$1.2 billion, depending on the technology platform selected and the associated infrastructure requirements. This estimate includes not only the acquisition and installation costs of smart meters, but also the costs of necessary billing system upgrades, telecommunication infrastructure and data management systems. Although there continues to be a high level of uncertainty surrounding the implementation details of the smart meters program, we anticipate that the resulting expenditures will be recoverable. The OEB is examining how to address any negative impacts associated with load reductions.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2005 (Canadian dollars in millions)	Total	2006	2007/2008	2009/2010	After 2010
Contractual Obligations <i>(due by year):</i>					
Long-term debt	5,084	589	895	800	2,800
Inergi LP (Inergi) outsourcing agreement ¹	600	110	205	183	102
Operating lease commitments	17	5	8	4	—
Total Contractual Obligations	5,701	704	1,108	987	2,902
Other Commercial Commitments <i>(by year of expiry):</i>					
Bank line ²	750	750	—	—	—
Letters of credit ³	106	106	—	—	—
Guarantees ³	275	275	—	—	—
Pension ⁴	89	81	8	—	—
Total Other Commercial Commitments	1,220	1,212	8	—	—

¹ On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

² As a backstop to our commercial paper program, we have a \$750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2006, with a two-year extension option.

³ We currently have bank letters of credit of \$82 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of \$21 million and parental guarantees of \$275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

⁴ Contributions to the pension fund are made one-month in arrears. Contributions after 2006 will be based on an actuarial valuation effective no later than December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, the company currently estimates annual pension contributions for 2007 and beyond to be in the range of \$100 million.

The long-term debt amounts in the above table are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or within our capital expenditures, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our statement of operations or within our capital expenditures.

RISK MANAGEMENT

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. The Hydro One Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices and our Chief Financial Officer for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Regulatory Risk

On August 17, 2005, we filed a rate application seeking approval for a \$160 million increase in the 2006 revenue requirement of Hydro One Networks' distribution business. As this is our first full cost of service rate submission since 1999 and as recent rate increases and commodity price increases have increased customer bills, we expect this submission to be closely examined by the OEB and intervenors. This could result in increased regulatory risk. For example, past or future expenditures could be disallowed or elements of the approved revenue requirement could be delayed. In addition, within the scope of this review, the OEB will examine the recoverability of certain pension costs incurred within our distribution business and recorded in a regulatory asset account. In accordance with an order from the OEB, we deferred the non-capital portion of our distribution-related pension costs incurred in 2004 and 2005 as a regulatory asset. These deferred expenditures amounted to \$76 million as at December 31, 2005, inclusive of interest. Should the OEB determine that some of these expenditures are not recoverable from customers, any disallowed amount will be charged to the results of operations when the decision is rendered.

RISK MANAGEMENT (continued)

The OEB's December 9, 2004 decision, which allowed for regulatory recovery of the majority of the regulatory asset amounts we applied for, has significantly reduced the proportion of our total regulatory asset balance at risk for future disallowance. However, there may still be some residual risk of future OEB disallowance of unreviewed account balances. In the event that some of these amounts are disallowed by the OEB during our 2006 rate review, any disallowed amount will be charged to the results of operations when the decision is rendered.

On October 26, 2005, the OEB initiated a proceeding to approve revenue requirements for our transmission business for the years 2006, 2007 and 2008. For the period from January 1, 2006 until revised rates are implemented, the OEB intends to track net income in excess of the currently approved returns. Tracking options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism. This results in a risk of having some of our transmission revenues (for the period from January 1, 2006 until new rates are implemented) recaptured if excess earnings occur. We have proposed an earnings-sharing mechanism that would result in any over earnings being returned to customers in the form of transmission system expansion projects that are critical to the economy of Ontario and to the secure operation of the system. Our proposal is consistent with practices recently utilized in other North American jurisdictions requiring significant system investments. A hearing on our proposal was held on November 25, 2005 and a decision is expected by the OEB in the first quarter of 2006. The initiation of a transmission proceeding also results in similar risks to those faced by our distribution business as a result of our recent rate application.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful conservation and demand management programs. The OEB has recognized the need to compensate utilities for any resulting lost revenue, but the approach, level and timing of any such compensation mechanism are yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets and compensating us by paying the net book value of bypassed assets as well as costs of removal and environmental remediation. This code revision could result in compensation that is not consistent with the value of retaining the assets. The *Transmission System Code* enables us to challenge investments by utility customers that may strand our assets. We intend to use this avenue to mitigate any substantive financial risks.

There is also a risk that we could be required to invest in large-scale transmission infrastructure projects and conservation initiatives, such as smart meters. While we expect these expenditures to be fully recoverable, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment in value and charges to our results of operations. We have no insurance for naturally occurring damage or catastrophe impacting our assets located outside of our transmission and distribution stations.

Ownership by the Province

The Province owns all of our outstanding shares and therefore controls our company. The Province has the power to determine the composition of our Board of Directors and may directly influence our major corporate decisions and business plans. As such, in making decisions that affect us, the Province can be expected to consider the best interests of all of the residents of Ontario as well as the specific interests of our company and our customers. Examples of areas where this balance must be exercised include structuring and regulating our company and Ontario's electricity industry, regulating environmental issues and determining the amounts to be paid by us as dividends.

Labour Risk

Approximately 25% of our staff are eligible for retirement by 2008. We expect the skilled labour market for our industry to be highly competitive in the future. If we are not able to attract or retain sufficient qualified staff, our operations and financial condition could be adversely affected.

We have a defined benefit registered pension plan for the majority of our employees. Our contributions to the pension plan are based on periodic actuarial valuations. Our most recent actuarial valuation, covering the period January 1, 2004 to December 31, 2006 inclusive, was filed with the Financial Services Commission of Ontario in September 2004. Under this valuation, we are obligated to make annual cash contributions to the pension plan of approximately \$80 million per year. The amount of the contributions that may be required after December 31, 2006 will depend on future investment returns, changes in benefits or actuarial assumptions.

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (The Society). As a result, in the case of future labour disputes we could face some degree of operational risk related to continued compliance with our license requirements of providing service to customers. We could also face financial risk related to our ability to negotiate collective agreements consistent with our rates. Existing collective agreements with the PWU and The Society expire in 2008.

Environmental Risk

We are subject to federal, provincial and municipal environmental regulations that are subject to change. Failure to comply could lead to government orders requiring us to take specific actions or could subject us to fines, penalties, or claims by third parties. Conducting environmental assessments and seeking government approvals for the construction of facilities could result in delays and cost increases.

Future changes in environmental regulations may result in material changes to the expenditure estimates used to calculate the carrying values of our environmental liabilities and associated regulatory assets. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet.

International scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to relocate some of our facilities, or face difficulties in locating and building new facilities.

RISK MANAGEMENT (continued)

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses on April 1, 1999 did not result in a transfer of title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Under the terms of our transfer orders, the OEFC will continue to hold these assets until we receive the federal and Indian band consents required for title transfer. After completion of title transfer, we expect our annual costs to exceed the amounts included in existing rate orders. If title transfer cannot be achieved, we expect that either the OEFC will continue to hold these assets or we will be required to relocate them, likely at significant expense. Such additional costs could have an adverse effect on our results of operations in the event we were unable to recover them in future rates.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2006 and 2007 would have an impact on net income of approximately \$2 million in 2006 and \$5 million in 2007.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of \$40 million. The fair value of the swap contract is not significant.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2005 amounted to \$430 million and principally relate to employee future benefits other than pension, the regulatory asset recovery account (RARA), environmental costs, pension costs and low-voltage services. We have also recorded regulatory liabilities amounting to \$525 million as at December 31, 2005. These amounts pertain primarily to pension costs, export and wheeling fees and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for the employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARA, or if future OEB direction is judged to be probable. Most of the regulatory asset amounts have been reviewed by the OEB and confirmed as recoverable and any remaining balances will be reviewed as part of the OEB's 2006 review of our distribution business. If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately \$80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs on an accrual basis are also disclosed in the notes to the financial statements. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 7.00% per annum is based on current expectations of long-term rates of return and reflects a pension asset mix consistent with the fund's investment policy of 57% held in equity securities, 38% held in corporate and government debt securities and 5% held in alternative assets consisting of hedge funds and private equity funds. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets exceeded this long-term assumption in 2005.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year-end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2005 have been reduced by 0.5% and 1.0%, varying by benefit plan, from those at December 31, 2004 in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

CRITICAL ACCOUNTING ESTIMATES (continued)

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in the service cost and interest cost of about \$12 million per year.

Employee future benefits are included in labour costs and charged to results of operations or are capitalized as part of the cost of fixed assets. Changes in the assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2005. As a result of our review, we determined that the carrying value of our goodwill has not been impaired.

EMERGING ACCOUNTING PRONOUNCEMENTS

Canadian Accounting Standards Board's Strategic Plan

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with International Financial Reporting Standards over an expected five-year transitional period. The AcSB will develop and publish a detailed implementation plan for achieving convergence later in 2006. At the end of that period, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we will begin our transition preparations early.

Accounting for Rate Regulated Operations

The AcSB has an active project to review GAAP applicable to enterprises with rate-regulated operations. The first phase resulted in the issue of Accounting Guideline AcG-19, *Disclosures by Entities Subject to Rate Regulation*. Our disclosures reflect these new requirements. In the second phase of its project, the AcSB plans to review whether regulatory accounting treatments, which are commonly applied throughout our industry, meet the definition of an asset or liability as defined by Canadian Institute of Chartered Accountants (CICA) Handbook Section 1000, *Financial Statement Concepts*. If the AcSB concludes that they do not, we would be required to discontinue the application of rate-regulated accounting. Specifically, we would no longer be able to recognize our regulatory assets and liabilities, which amounted to \$430 million and \$525 million, respectively at December 31, 2005. As well, we may be required to account for payments in lieu of corporate income taxes related to our regulated business on a liability basis. The net effect of these changes would be charged to either retained earnings or results of operations once the new accounting standard became effective, dependent on the transition rules. At this time, it is uncertain what decision the AcSB will reach. However, we do not believe that the outcome of this project will have a material financial impact on our company.

Financial Instruments

During 2005, the AcSB completed its project on the recognition and measurement of financial instruments by issuing new recommendations dealing with financial instruments and hedging and by introducing the concept of other comprehensive income. Under the new accounting standards, which come into effect for our 2007 fiscal year, all financial instruments, including derivatives, must be included on a company's balance sheet and measured at fair value or, in limited circumstances when fair value may not be the most relevant basis, at cost or amortized cost. The standards also specify when gains and losses resulting from changes in fair value are to be recognized in the Statement of Operations. Existing requirements for hedge accounting are extended and clarified. In addition, certain gains and losses will be reported as other comprehensive income. We are assessing the overall impact of the new accounting standards, but do not believe that their application will have a material financial impact on our company.

Accounting for Conditional Asset Retirement Obligations

In December 2005, the Emerging Issues Committee (EIC) of the CICA issued EIC-159, *Conditional Asset Retirement Obligations*. This pronouncement governs the accounting for asset retirement obligations where the method or timing of disposal of an asset is conditional on some future event. The new pronouncement is effective for annual and interim periods ending after March 31, 2006. We have reviewed the new EIC pronouncement and do not expect that it will have a material impact upon our company.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a reporting issuer, we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. We completed our initial evaluation of our disclosure controls during the fourth quarter of 2005 and we anticipate completing our evaluation of our internal controls over financial reporting in 2006. Evaluations will continue to be conducted on an ongoing basis to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the consolidated financial statements for the year ended December 31, 2005, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been put in place, and that these controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

OUTLOOK

We will continue to concentrate on our top strategic priorities, which are to create and maintain an injury-free workplace with a concentrated focus on the elimination of serious injuries or close calls having the potential to cause serious injury; to further enhance the reliability of our transmission and distribution networks; and to improve our customers' levels of satisfaction. To these ends, we have renewed our focus on incident prevention and proactive applications, and we are making significant investments to address asset condition and improve reliability by maintaining and selectively increasing work program spending levels. In particular, we will ensure

OUTLOOK (continued)

that Ontario's needs for performance from our aging transmission system under tight generation supply conditions are met. Key transmission investment areas include assets critical to supporting generating stations and reducing congestion on the main transmission grid, such as key transformer station upgrades and high-voltage line replacements, and protection and control equipment replacements. Key distribution investment areas include vegetation management, increased wood pole replacements, feeder sectionalization and defect management, as well as customer care programs and the conservation and demand management program.

Consistent with our 10-year transmission plan, *Transmission Solutions 2005–2014*, we will make the necessary investments in our transmission infrastructure to ensure that growing area supply needs, and system configuration and reliability requirements, are successfully met. In particular, we intend to make area supply improvements in the Greater Toronto Area (including central Toronto and adjoining communities) as well as across Ontario. Further, we will complete the Niagara Reinforcement Project and we expect to undertake other reinforcement projects as the needs for transmission system investments are further identified by the OPA in its pending IPSP. As part of these initiatives, we will work closely with the OPA, the OEB, and other stakeholders, related or affected parties.

There is significant potential for the IPSP to include large scale transmission infrastructure investments not currently included within our investment plans. Examples include the Manitoba-Ontario high capacity lines, major new supply lines to Toronto, and new generation investment projects including those related to the retirement of coal-fired generation. Funding is also not included for the implementation of smart meters. We would need to reach agreements with all affected parties and have a reasonable expectation of recovery before proceeding with such large, complex undertakings.

The Province is continuing to examine the state of the electricity market and industry within Ontario. While we are not anticipating structural changes, such changes are possible, for example in the form of electricity distribution sector rationalization or as the result of municipal border dispute settlements. We will continue to work with the Government to assist them in their deliberations and will work cooperatively to implement any changes. In the interim, the Government expects us not to enter into further transactions involving the acquisition or divestment of LDCs or distribution assets.

With the amendments to the legislation affecting the electricity industry and the OEB's mandate, the approval for recovery of distribution regulatory assets in December 2004 and the anticipated distribution rate increases in 2006, we anticipate a stable regulatory environment for our distribution business going forward. However, the OEB has initiated a review of our revenue requirement for the transmission business and we are anticipating a decision in the first quarter of 2006 regarding a proposed earnings sharing mechanism. Given the need for transmission infrastructure across the province to ensure reliability and economic vitality, we proposed that any excess earnings subject to a sharing mechanism be utilized to fund these projects. We will prepare our regulatory evidence in the interest of all Ontarians.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

FORWARD LOOKING STATEMENTS AND INFORMATION

We have included forward-looking statements in this report that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. Any statement contained in this document that is not current or historical is a forward-looking statement. We have based these forward-looking statements on historical experience, current conditions and various assumptions believed to be reasonable in the circumstances. Actual results could differ materially from those projected in the forward-looking statements. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or otherwise.

This management's discussion and analysis is dated as at February 15, 2006. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 15, 2006.

In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 54, outlines the scope of their examination and their opinion.

— Management's Report —

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:



Tom Parkinson
President and Chief Executive Officer



Beth Summers
Chief Financial Officer



Executive Committee

Beth Summers
Chief Financial Officer

Tom Parkinson
President and Chief Executive Officer

Laura Formosa
General Counsel and Secretary

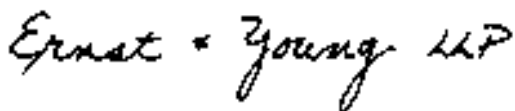
—Auditors' Report—

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2005 and December 31, 2004, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2005. 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 audits.

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

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and December 31, 2004, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2005, in accordance with Canadian generally accepted accounting principles.



Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 15, 2006

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Revenues		
Transmission (Note 15)	1,310	1,262
Distribution (Notes 3 and 15)	3,085	2,874
Other	21	17
	4,416	4,153
Costs		
Purchased power (Notes 3 and 15)	2,131	1,987
Operation, maintenance and administration	792	771
Depreciation and amortization (Note 5)	487	480
	3,410	3,238
Regulatory recovery (Note 4)	—	91
Income before financing charges and provision for payments in lieu of corporate income taxes	1,006	1,006
Financing charges (Note 6)	325	331
Income before provision for payments in lieu of corporate income taxes	681	675
Provision for payments in lieu of corporate income taxes (Notes 7 and 15)	198	177
Net income	483	498
Basic and fully diluted earnings per common share (Canadian dollars) (Note 14)	4,652	4,798

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Retained earnings, January 1	887	654
Net income	483	498
Dividends (Note 14)	(291)	(265)
Retained earnings, December 31	1,079	887

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2005	2004
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - \$18 million; 2004 - \$18 million) <i>(Note 15)</i>	622	707
Materials and supplies	56	47
	678	754
Fixed assets <i>(Note 8)</i> :		
Fixed assets in service	15,553	14,940
Less: accumulated depreciation	5,818	5,475
	9,735	9,465
Construction in progress	381	348
	10,116	9,813
Other long-term assets:		
Deferred pension asset <i>(Note 12)</i>	449	534
Regulatory assets <i>(Note 9)</i>	430	443
Goodwill	133	133
Long-term accounts receivable and other assets	20	25
Deferred debt costs	23	23
	1,055	1,158
Total assets	11,849	11,725

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

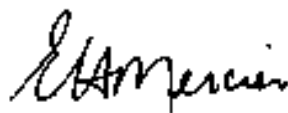
December 31 (Canadian dollars in millions)	2005	2004
Liabilities		
Current liabilities:		
Bank indebtedness	9	9
Accounts payable and accrued charges (Note 15)	700	630
Accrued interest	43	44
Short-term notes payable (Note 10)	—	40
Long-term debt payable within one year (Note 10)	589	539
	1,341	1,262
Long-term debt (Note 10)	4,466	4,613
Other long-term liabilities:		
Regulatory liabilities (Note 9)	525	576
Employee future benefits other than pension (Note 12)	716	654
Environmental liabilities (Note 13)	64	74
Long-term accounts payable and accrued charges	21	22
	1,326	1,326
Total liabilities	7,133	7,201
Contingencies and commitments (Notes 11, 17 and 18)		
Shareholder's equity (Note 14)		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,079	887
Total shareholder's equity	4,716	4,524
Total liabilities and shareholder's equity	11,849	11,725

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:



Rita Burak
Chair



Eileen Mercier
Chair, Audit and Finance Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Operating activities		
Net income	483	498
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	446	446
Amortization of discount	59	62
Low-voltage services	(24)	—
Retail settlement variance accounts	12	29
Regulatory recovery (Note 4)	—	(91)
	976	944
Changes in non-cash balances related to operations (Note 16)	194	(33)
Net cash from operating activities	1,170	911
Investing activities		
Capital expenditures	(691)	(727)
Other assets	9	19
Net cash used in investing activities	(682)	(708)
Financing activities		
Long-term debt issued	500	540
Long-term debt retired	(648)	(472)
Short-term notes payable	(40)	15
Dividends paid	(291)	(265)
Termination of interest rate swap	(10)	—
Other	1	7
Net cash used in financing activities	(488)	(175)
Net change in cash and cash equivalents	—	28
Cash and cash equivalents, January 1	(9)	(37)
Cash and cash equivalents, December 31 (Note 16)	(9)	(9)

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario). The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB will consider options to track net income excesses or deficiencies compared to approved returns for the period from January 1, 2006 until revised transmission rates are implemented. The options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. Current distribution rates are based on a cost of service rate regulation model, which also includes a targeted return of 9.88% on deemed common equity. In August 2005, Hydro One Networks filed a distribution rate application seeking approval for a \$160 million increase in the 2006 revenue requirement for its distribution business. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting,

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 9.

On December 9, 2004, the OEB issued its decision on the prudence of various regulatory deferral accounts incurred prior to December 31, 2003, plus related interest. As a result of the OEB's decision, the proportion of our regulatory assets subject to potential future OEB disallowance has been significantly reduced. However, regulatory asset amounts included in approved accounts that were recognized after December 31, 2003 have not yet been reviewed by the OEB. Similarly, the Company's deferred distribution-related pension expenditures have not yet been reviewed by the OEB for prudence. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2005 amounted to \$377 million (2004 - \$318 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the 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 *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2005 – 6.8%; 2004 - 7.0%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Transmission	12 - 100	57
Distribution	15 - 75	41
Communication	7 - 40	21
Administration and service	5 - 50	41

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies (LDCs) in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Under Canadian Institute of Chartered Accountants Handbook Section 3062, *Goodwill and Other Intangible Assets*, goodwill impairment is assessed based on a comparison of the fair value of the

reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Derivative Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations.

The Company does not engage in derivative trading or speculative activities.

Discounts, Premiums and Hedging

Discounts, premiums and hedging gains and losses are amortized over the period of the related debt.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. ELECTRICITY CREDITS TO CUSTOMERS

Under a new regulation issued in October 2005, Regulated Price Plan customers receive a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by \$140 million. The application of the one-time credit did not result in any adjustment to net income in the current or previously reported periods.

4. REGULATORY RECOVERY

The *Electricity Pricing, Conservation and Supply Act, 2002*, suspended a previously approved rate increase related to annual low-voltage services costs for embedded LDCs and direct customers. The associated costs are charged annually to the Company's results of operations. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002*, also allowed for establishment of a regulatory deferral account to record suspended low-voltage services amounts to be recovered from future customers. Due to uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 9, 2004 were not previously recognized as regulatory assets. Similarly, the Company did not reflect certain other costs, such as interest, as regulatory assets in prior years' financial statements.

On May 31, 2004, Hydro One applied for recovery of approximately \$156 million included within various regulatory deferral accounts prior to December 31, 2003. The requested recovery primarily included the low-voltage services amounts not previously recognized as regulatory assets, as well as interest on all of the requested balances. As a result of the oral and written evidence submitted by Hydro One, the OEB issued a decision on December 9, 2004 regarding the prudence of the distribution-related deferral account balances included in the application. The OEB approved all but approximately \$12 million of the requested amount for recovery over the period ending April 30, 2008. As a result of this successful regulatory recovery, the Company recorded an increase in its regulatory asset balance, which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue.

The 2004 regulatory recovery consisted of the following components:

Year ended December 31 (Canadian dollars in millions)	2004
Low-voltage services – 2002	17
Low-voltage services – 2003	25
Low-voltage services – 2004	23
Interest accretion	18
Other	8
	91

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	2005	2004
Depreciation of fixed assets in service	369	370
Fixed asset removal costs	41	34
Amortization of regulatory and other assets	77	76
	487	480

6. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	2005	2004
Interest on short-term notes payable	1	1
Interest on long-term debt payable	297	286
Amortization of discount	58	62
Other	5	7
Less: Interest capitalized on construction in progress	(21)	(23)
Interest capitalized on regulatory assets	(10)	—
Interest earned on investments	(5)	(2)
	325	331

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004
Income before provision for PILs	681	675
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	246	244
(Decrease) increase resulting from:		
Net temporary differences:		
Pension contribution in excess of pension expense	(25)	(23)
Subsidiary loss carryforward	(21)	—
Regulatory recovery	—	(33)
Interest capitalized for accounting purposes but deducted for tax purposes	(11)	(8)
Employee future benefits other than pension expense in excess of cash payments	8	9
Environmental expenditures	(5)	(6)
Capital cost allowance less than (in excess of) depreciation and amortization	1	(7)
Other	(9)	(9)
Net temporary differences	(62)	(77)
Permanent differences:		
Large corporations tax	13	16
Other	1	(6)
Net permanent differences	14	10
Provision for PILs	198	177
Effective income tax rate	29.07%	26.22%

In May 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to access the subsidiary's accumulated tax losses and a future tax asset of approximately \$21 million was recognized in the second quarter. As at December 31, 2005, approximately \$9 million of this amount remains available for use in 2006.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2005, future income tax liabilities of \$265 million (2004 - \$224 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized on an accrual basis rather than under the taxes payable method. As a result, the provision for PILs would have been higher by approximately \$41 million.

8. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2005				
Transmission	8,124	2,889	239	5,474
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	—	421
	15,553	5,818	381	10,116
2004				
Transmission	7,833	2,753	249	5,329
Distribution	5,066	1,884	55	3,237
Communication	744	309	31	466
Administration and service	816	471	13	358
Easements	481	58	—	423
	14,940	5,475	348	9,813

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were \$21 million in 2005 (2004 - \$23 million).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities (see Notes 2 and 4):

December 31 (Canadian dollars in millions)	2005	2004
Regulatory assets:		
Employee future benefits other than pension	126	168
Regulatory asset recovery account	88	121
Environmental	79	89
Pension	76	34
Low-voltage services	53	26
Other	8	5
Total regulatory assets	430	443
Regulatory liabilities:		
Deferred pension	449	534
Export and wheeling fees	32	19
Retail settlement variance accounts	30	14
Other	14	9
Total regulatory liabilities	525	576

9. REGULATORY ASSETS AND LIABILITIES (continued)

Regulatory assets

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of \$419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 3 years (2004 - 4 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately \$42 million.

Regulatory asset recovery account (RARA)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by Hydro One in its May 31, 2004 application (see Note 4). Recoverable amounts represent balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately \$20 million. In addition, related financing charges would have been higher by \$7 million.

Environmental

Hydro One provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower and operation, maintenance and administration expense would have been higher by \$14 million. During 2004, the Company identified an increased risk associated with potential offsite migration of contamination in storm water run-off from some of its transmission sites. Given the need to address this issue, in 2004 the Company adjusted its future land assessment and remediation expenditure estimate and increased its regulatory asset and offsetting environmental obligation by approximately \$16 million (see Note 13). The OEB has the discretion to examine and assess the prudence and the timing of recovery of Hydro One's future regulatory expenditures.

Pension

In a July 14, 2004 decision, the OEB approved the Company's establishment of a regulatory account to record the Company's distribution-related pension contributions that would otherwise have been charged to results of operations. The regulatory asset also includes amounts payable to Inergi LP (Inergi) commencing in 2005 in

respect of a risk sharing agreement related to the imbalance between pension fund assets and liabilities in respect of transferred staff (see Note 18). In its decision, the OEB concluded that prudently incurred expenditures of this type are generally recoverable as part of a general rate application. The Company has included a request for recovery as part of its distribution rate application currently under review by the OEB.

Low-voltage services

The OEB's December 9, 2004 decision allows for delayed recovery of previously approved low-voltage system amounts, within the RARA, for the period up to December 31, 2003. Given this decision, the Company has determined that it is probable that, at some future date, the OEB will also approve recovery of the low-voltage amounts attributable to 2004 and 2005, plus interest. As a result, the Company has recognized a regulatory asset reflecting this probable future recovery.

Regulatory liabilities

Deferred pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid to the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately \$38 million, assuming no regulatory deferral of distribution and Inergi pension-related amounts. In addition, related financing charges would have been higher by \$4 million.

Export and wheeling fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of \$1 per MW on electricity exported outside of Ontario. The Company expects that amounts collected in respect of this export and wheeling fee, plus interest, will be taken into consideration by the OEB in assessing the revenue requirement of our transmission business as part of the Company's next general transmission rate application.

Retail settlement variance accounts

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allows for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA. The Company anticipates that OEB will include the net balance of this regulatory account in future rates.

10. DEBT

December 31 (Canadian dollars in millions)	2005	2004
Short-term notes payable	—	40
Long-term debt:		
6.94% debentures due 2005	—	200
4.00% notes due 2005	—	339
4.10% notes due 2006 ¹	—	109
4.15% notes due 2006	280	280
4.20% notes due 2006	168	168
4.30% notes due 2006	141	141
4.45% notes due 2007	282	282
4.55% notes due 2007	73	73
4.10% notes due 2007 ²	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	250
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	350	—
6.59% notes due 2043	315	315
	5,084	5,232
Less: Long-term debt payable within one year	(589)	(539)
Net unamortized discounts	(14)	(73)
Unamortized hedging losses	(15)	(7)
Long-term debt	4,466	4,613

¹ 4.10% notes due 2006 were redeemed on December 16, 2005.

² Step-up coupon, after year 3 from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2004, the notes had a weighted-average interest rate of 2.3%.

Hydro One has a \$750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2006, with a two-year extension option. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's commercial paper program.

The Company issues notes for long-term financing under the medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is \$2,500 million of which the full amount is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2005, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures (Canadian dollars in millions)	Weighted Average Interest Rate (%)
1 year	589	4.2
2 years	395	4.4
3 years	500	4.0
4 years	400	4.0
5 years	400	7.2
	2,284	4.7
6 – 10 years	850	6.0
Over 10 years	1,950	6.6
	5,084	5.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year-end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2005		2004	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt ¹	5,084	5,697	5,232	5,658

¹ The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into forward fixed interest rate swap agreements or forward sale agreements of Government of Canada bonds to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2004, Hydro One entered into a forward interest rate swap agreement with a notional principal amount of \$100 million to lock in the interest rate of a future issuance planned for 2005. In 2005, Hydro One entered into an additional forward interest rate swap agreement to lock in a further \$50 million in notional principal. During 2005, the Company terminated both forward interest rate agreements for a net cash payment of \$10 million that is being amortized on an annuity basis over the thirty-year term of the related debt.

As at December 31, 2005, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of \$40 million.

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2005 (2004 - \$nil).

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2005, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2005, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

12. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately \$1 million annually.

Plan Allocation

Hydro One's pension plan asset allocation at December 31, 2005 and 2004 was as follows:

December 31	% of Plan Assets	
	2005	2004
Equity securities	60.6	59.2
Debt securities	36.2	36.2
Other	3.2	4.6
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities in the Province of \$79 million and \$83 million at December 31, 2005 and 2004 respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, the Company contributed \$83 million to its pension plan in respect of 2005 (2004 - \$74 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation date no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2005, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was \$123 million in 2005 (2004 - \$110 million).

Year ended December 31 (Canadian dollars in millions)	Pension		Employee Future Benefits other than Pension	
	2005	2004	2005	2004
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	4,862	4,323	966	897
Current service cost	83	76	26	24
Interest cost	277	254	57	54
Benefits paid	(248)	(232)	(40)	(36)
Plan amendments	—	—	1	—
Net actuarial loss	381	441	133	27
Accrued benefit obligation, December 31	5,355	4,862	1,143	966
Change in plan assets				
Fair value of plan assets, January 1	4,243	3,939	—	—
Actual return on plan assets	630	458	—	—
Benefits paid	(248)	(232)	—	—
Employer's contributions ¹	83	74	—	—
Employees' contributions	16	16	—	—
Administrative expenses	(11)	(12)	—	—
Fair value of plan assets, December 31	4,713	4,243	—	—
Funded status				
(Unfunded benefit obligation)	(642)	(619)	(1,143)	(966)
Unamortized net actuarial losses	1,069	1,128	385	271
Unamortized past service costs	22	25	6	6
Deferred pension asset (accrued benefit liability)	449	534	(752)	(689)
Less: current portion	—	—	36	35
Deferred pension asset (long-term liability)	449	534	(716)	(654)

¹ In January, 2006, the Company made a contribution of \$8 million in respect of 2005 (2005 - \$7 million in respect of 2004).

12. EMPLOYEE FUTURE BENEFITS (continued)

Year ended December 31 (Canadian dollars in millions)	Pension		Employee Future Benefits other than Pension	
	2005	2004	2005	2004
Components of net periodic benefit cost				
Current service cost, net of employee contributions	67	60	26	24
Interest cost	277	254	57	54
Actual return on plan asset net of expenses	(619)	(446)	—	—
Actuarial loss	381	441	133	27
Other	—	—	—	(1)
Costs arising in the period	106	309	216	104
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	327	174	—	—
Actuarial gain	(268)	(362)	(113)	(11)
Plan amendments	3	3	—	1
Net periodic benefit cost ²	168	124	103	94
Charged to results of operations ²	23	22	64	56
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	—	—	171	124
Service cost and interest cost	—	—	12	11
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	—	—	(133)	(108)
Service cost and interest cost	—	—	(10)	(9)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	7.00%	7.00%	—	—
Weighted-average discount rate	5.75%	6.00%	5.93%	6.18%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.75%	2.25%	2.75%	2.25%
Average remaining service life of employees (years)	10	12	10	11
Rate of increase in health care cost trend ³	—	—	4.40%	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	5.00%	5.75%	4.98%	5.93%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.75%	2.50%	2.75%
Rate of increase in health care cost trend ⁴	—	—	4.40%	4.40%

² The Company follows the cash basis of accounting. During 2005, pension costs of \$83 million (2004 - \$81 million) were attributed to labour, of which \$23 million (2004 - \$22 million) was charged to operations, \$32 million (2004 - \$31 million) was capitalized as part of the cost of fixed assets, and \$28 million (2004 - \$28 million) was attributed to a regulatory asset.

³ 8.47% in 2005 grading down to 4.40% per annum in and after 2014 (2004 - 9.00% in 2004 grading down to 4.40% per annum in and after 2014).

⁴ 7.87% in 2006 grading down to 4.40% per annum in and after 2014 (2004 - 8.47% in 2004 grading down to 4.40% per annum in and after 2014).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	2005	2004
Environmental liabilities, January 1	89	83
Interest accretion	5	5
Expenditures	(14)	(15)
Revaluation adjustment (Note 9)	(1)	16
Environmental liabilities, December 31	79	89
Less: current portion	(15)	(15)
	64	74

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - \$15 million; 2007 - \$14 million; 2008 - \$12 million; 2009 - \$10 million; 2010 - \$9 million; and thereafter - \$40 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

14. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of \$25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of \$18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of \$25.00 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2005, preferred dividends in the amount of \$18 million (2004 - \$18 million) and common dividends in the amount of \$273 million (2004 - \$247 million) were declared.

14. SHARE CAPITAL (continued)

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

15. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2005 includes \$1,276 million (2004 - \$1,228 million) related to these services.

Hydro One received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2005 includes \$21 million (2004 - \$21 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2005 includes \$127 million related to this program. In 2004, the Company also received \$127 million for rural rate protection, of which \$1 million was paid to LDCs in respect of annexation agreements.

In 2005, Hydro One purchased power in the amount of \$2,095 million (2004 - \$1,951 million) from the IESO administered electricity market and \$36 million (2004 - \$36 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2005, Hydro One incurred \$7 million (2004 - \$10 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were \$11 million (2004 - \$11 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than \$1 million in each of 2005 and 2004.

The provision for payments in lieu of corporate income taxes was paid or payable to OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2005	2004
Accounts receivable	116	120
Accounts payable and accrued charges	(263)	(247)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of \$213 million (2004 - \$200 million).

16. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the consolidated statements of cash flows, “cash and cash equivalents” refers to the balance sheet item “bank indebtedness.”

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2005	2004
Accounts receivable decrease (increase)	85	(91)
Materials and supplies increase	(9)	(2)
Accounts payable and accrued charges increase	70	10
Accrued interest (decrease) increase	(1)	6
Long-term accounts payable and accrued charges decrease	(1)	(9)
Employee future benefits other than pension increase	62	57
Other	(12)	(4)
	194	(33)
Supplementary information:		
Interest paid	300	285
Payments in lieu of corporate income taxes	210	207

17. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have an adverse effect on the Company's consolidated financial position, results of operations or cash flows.

As a result of Hydro One's acquisition of certain transmission, distribution and energy services assets, liabilities, rights and obligations of Ontario Hydro, Hydro One has succeeded Ontario Hydro as a party in a number of legal proceedings. On September 1, 1995, Torcom Communications Inc. (Torcom) named Ontario Hydro as one of several defendants in a suit seeking damages of \$150 million, as well as specific performance of certain agreements and interim injunctive relief. Torcom had sought to purchase certain telecommunication devices belonging to a bankrupt company from the court-appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995, when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not yet served a statement of defence. Hydro One believes that there are strong defences to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of the litigation will have a material adverse effect on its business, results of operations, financial position or prospects. Torcom has not proceeded with this claim for almost ten years.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG

17. CONTINGENCIES (continued)

and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty, and compensation for costs incurred in the course of prior negotiations of band grievances with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. This case was consolidated with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than \$850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

18. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period. The initial service level price ranges between \$90 million and \$130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2005, and in total thereafter are as follows: 2006 - \$110 million; 2007 - \$108 million, 2008 - \$97 million; 2009 - \$93 million; 2010 - \$90 million; and thereafter - \$102 million.

Additionally, the outsourcing agreement with Inergi includes a risk sharing agreement involving either Hydro One or Inergi making a payment related to a past imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement was settled based on data available on December 31, 2004, reflecting economic factors and pension fund rates of return. Hydro One is required to pay Inergi approximately \$17 million equally over the next two years.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2005, the Company provided prudential support, using a combination of bank letters of credit of \$21 million (2004 - \$33 million) and parental guarantees of \$275 million (2004 - \$275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2005, Hydro One had bank letters of credit of \$82 million (2004 - \$80 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - \$5 million; 2007 - \$4 million; 2008 - \$4 million; 2009 - \$4 million; 2010 - \$nil; and thereafter - \$nil.

19. SEGMENT REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The “other” segment, which primarily consists of the telecommunications business. Hydro One is currently in the process of assessing its strategy with respect to these operations.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2005				
Segment profit				
Revenues	1,310	3,085	21	4,416
Purchased power	—	2,131	—	2,131
Operation, maintenance and administration	353	413	26	792
Depreciation and amortization	246	236	5	487
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	711	305	(10)	1,006
Financing charges				325
Income before provision for payments in lieu of corporate income taxes				681
Capital expenditures	349	338	4	691
2004				
Segment profit				
Revenues	1,262	2,874	17	4,153
Purchased power	—	1,987	—	1,987
Operation, maintenance and administration	356	392	23	771
Depreciation and amortization	241	234	5	480
Income (loss) before financing charges, provision for payments in lieu of corporate income taxes and regulatory recovery	665	261	(11)	915
Regulatory recovery				91
Income before financing charges and provision for payments in lieu of corporate income taxes				1,006
Financing charges				331
Income before provision for payments in lieu of corporate income taxes				675
Capital expenditures	432	288	7	727

— Notes to Consolidated Financial Statements —

December 31 (Canadian dollars in millions)	2005	2004
Total assets		
Transmission	6,832	6,785
Distribution	4,925	4,845
Other	92	95
	11,849	11,725

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	2005	2004	2003	2002	2001
Statement of operations data					
Revenues					
Transmission	1,310	1,262	1,298	1,317	1,259
Distribution	3,085	2,874	2,734	2,682	2,158
Other	21	17	26	32	49
	4,416	4,153	4,058	4,031	3,466
Costs					
Purchased power	2,131	1,987	1,872	1,858	1,267
Operation, maintenance and administration ¹	792	771	795	832	824
Depreciation and amortization	487	480	454	411	384
	3,410	3,238	3,121	3,101	2,475
Regulatory recovery ²	—	91	—	—	—
Income before financing charges and provision for payments in lieu of corporate income taxes	1,006	1,006	937	930	991
Financing charges	325	331	348	353	350
Income before provision for payments in lieu of corporate income taxes	681	675	589	577	641
Provision for payments in lieu of corporate income taxes	198	177	193	233	267
Net income	483	498	396	344	374
Basic and fully diluted earnings per common share (Canadian dollars)	4,652	4,798	3,779	3,258	3,562
December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	6,832	6,785	6,589	6,638	6,693
Distribution	4,925	4,845	4,623	4,694	4,416
Other	92	95	94	90	122
Total assets	11,849	11,725	11,306	11,422	11,231
Liabilities					
Current liabilities (including current portion of long-term debt)	1,341	1,262	1,192	1,894	1,625
Long-term debt	4,466	4,613	4,539	3,938	4,079
Other long-term liabilities	1,326	1,326	1,284	1,451	1,533
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	1,079	887	654	502	357
Total liabilities and shareholder's equity	11,849	11,725	11,306	11,422	11,231

— Five-Year Summary of Financial and Operating Statistics —

Year ended December 31 (Canadian dollars in millions)	2005	2004	2003	2002	2001
Other financial data					
Capital expenditures					
Transmission	349	432	289	260	274
Distribution ³	338	288	292	286	247
Other	4	7	16	24	45
Total capital expenditures	691	727	597	570	566
Ratios					
Net asset coverage on long-term debt ⁴	1.93	1.88	1.86	1.90	1.88
Earnings coverage ratio ⁵	2.69	2.70	2.43	2.35	2.53
Operating statistics					
Transmission					
Units transmitted (TWh) ⁶	157.0	153.4	151.7	153.2	146.9
Ontario 20-minute system peak demand (MW) ⁶	26,219	25,204	24,849	25,629	25,269
Ontario 60-minute system peak demand (MW) ⁶	26,160	24,979	24,753	25,414	25,239
Total transmission lines (circuit-kilometres)	28,547	28,643	28,621	28,492	28,387
Distribution					
Units distributed to Hydro One customers (TWh) ⁶	29.7	28.5	27.9	27.1	21.3
Units distributed through Hydro One lines (TWh) ^{6,7}	45.6	44.8	44.7	45.1	41.3
Total distribution lines (circuit-kilometres)	122,118	121,736	121,285	120,767	120,448
Customers	1,273,768	1,258,925	1,238,748	1,219,614	1,193,089
Total regular employees	4,189	4,118	3,967	3,933	4,815

¹ Operation, maintenance and administration costs for 2002 included a charge of \$25 million for a staff reduction program.

² As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of \$91 million was recorded.

³ Capital expenditures exclude \$468 million in 2001 associated with acquisitions of LDCs.

⁴ The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

⁵ The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

⁶ System related statistics include preliminary figures for December.

⁷ Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO. Prior to Open Access in 2002, these consumers purchased power directly from the predecessor of OPG.

SENIOR MANAGEMENT TEAM



Tom Parkinson
President and
Chief Executive Officer

Laura Formusa
General Counsel and
Secretary

Geoff Ogram
Vice-president,
Strategy and Development



Wayne Smith
Vice-president,
Grid Operations

Steve Dorey
Vice-president,
External Relations

Peter Gregg
Vice-president, Executive office
and Corporate Communications

— Senior Management Team —



Nairn McQueen

Vice-president,
Engineering and
Construction Services

Rick Kellestine

Vice-president,
Culture

Myles D'Arcey

Senior Vice-president,
Customer Operations



Beth Summers

Chief Financial Officer

John Fraser

Vice-president,
Internal Audit and
Chief Risk Officer

Tom Goldie

Senior Vice-president,
Corporate Services

BOARD OF DIRECTORS



Rita Burak

Chair of the Board of Directors,
Hydro One Inc.



Sami Bébawi

Executive Vice President,
Office of the President,
President, Socotec Inc.,
SNC-Lavalin Group Inc.



Murray J. Elston

President and CEO, Canadian
Nuclear Association



Don MacKinnon

President,
Power Workers' Union



Eileen A. Mercier

Corporate Director



Walter Murray

Corporate Director



Kathleen O'Neill

Corporate Director



Tom Parkinson

President and CEO,
Hydro One Inc.



Hon. Bob Rae

Partner, Goodmans LLP



Douglas E. Speers

Chairman and Director,
Emco Corporation



Kenneth D. Taylor

Chair, Taylor and Ryan Inc.



Blake Wallace, Q.C.

Vice President and Director,
Murray & Company



W. Geoffrey Beattie

President, The Woodbridge
Company Limited
Resigned November 10, 2005



Dr. Murray B. Frum

Chair and CEO,
Frum Development Group
Resigned September 29, 2005



Adam Zimmerman

Corporate Director
Resigned July 18, 2005

BOARD COMMITTEES

Audit and Finance Committee

The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met four times in 2005.

Members: Eileen Mercier, *Chair*. Murray Elston, Walter Murray, Kathleen O'Neill, Douglas Speers

Corporate Governance Committee

The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandates of each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2005.

Members: Blake Wallace, *Chair*. Rita Burak, Eileen Mercier, Hon. Bob Rae

Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met seven times in 2005.

Members: Hon. Bob Rae, *Chair*. Walter Murray, Kathleen O'Neill, Blake Wallace

Regulatory and Environment Committee

The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met five times in 2005.

Members: Murray Elston, *Chair*. Sami Bébawi, Don MacKinnon, Kenneth Taylor, Blake Wallace

Health and Safety Committee

The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2005.

Members: Don MacKinnon, *Chair*. Sami Bébawi, Douglas Speers, Kenneth Taylor

COPORATE INFORMATION

Corporate Address

483 Bay Street
Toronto, Ontario
M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations

(416) 345-6867
investor.relations@HydroOne.com

Media Inquiries

(416) 345-6868
1-877-506-7584

Customer Inquiries

Power outage and emergency number:
1-800-434-1235

Residential, farm & small business accounts:
1-888-664-9376

Business accounts: 1-877-447-4412

Auditors

Ernst & Young LLP



Electricity Highway

Transmission towers reliably deliver electricity all across the province and ensure that businesses, families and communities have the power they need to prosper.



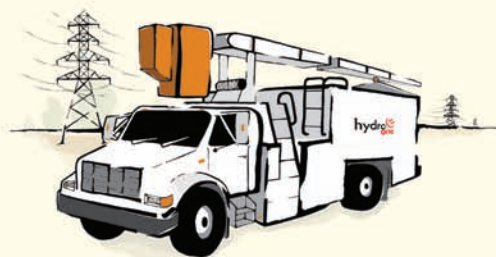
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Hydro One Inc.

483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com



Putting power to work

Hydro One Annual Report 2006

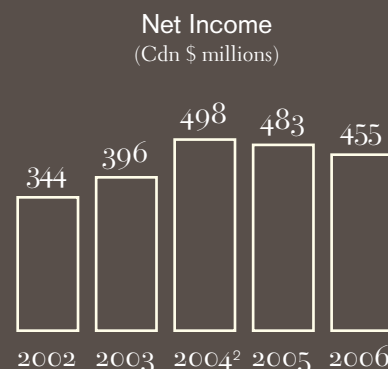
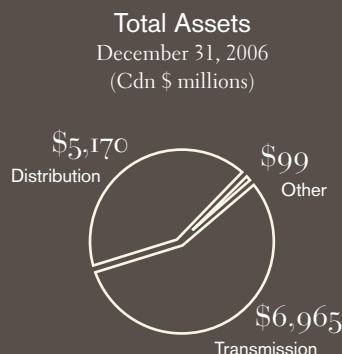
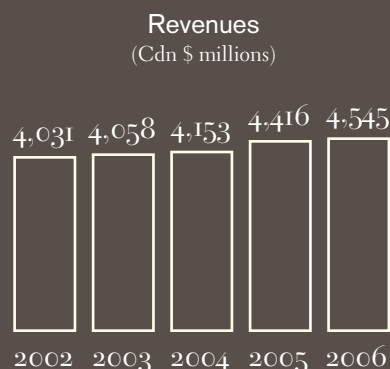
Consolidated financial

highlights and statistics

Year ended December 31
(Canadian dollars in millions)

	2006	2005	Change	% Change
Revenues	4,545	4,416	129	3
Purchased power	2,221	2,131	90	4
Operating costs	1,395	1,279	116	9
Net income	455	483	(28)	(6)
Net cash from operations	896	1,169	(273)	(23)
Average annual Ontario 60-minute peak demand (MW)¹	22,650	23,074	(424)	(2)
Distribution – units distributed to our customers (TWh)¹	29.0	29.7	(0.7)	(2)

¹ System-related statistics include preliminary figures for December.



² Net income for 2004 includes a one-time regulatory recovery of \$91 million.

The Hydro One Family of Companies

Hydro One Inc.

Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom. The subsidiaries are necessary to meet legislative and regulatory requirements.

Hydro One Networks Inc.

Represents the significant majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.

Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.

Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.

Markets our fibre-optic capacity to business customers and represents less than 1% of our total assets.

Our power at work

Customer satisfaction continued to climb in 2006, with

86%

of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

During a two-month period, three intense storms tested Ontario and knocked out power to more than 400,000 of our customers. The excellence of our restoration efforts earned us a prestigious *Emergency Recovery Award* from the Edison Electric Institute. This is the first time this award has gone to a utility based outside of the United States.

The Ontario Energy Board approved an increase of approximately

\$160M

The North American Electric Reliability Council (NERC) awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. NERC's audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

in our annual distribution revenue requirement. This decision demonstrates the OEB's confidence in our ability to maintain and operate Ontario's electricity system. The increased funds will enable us to make important investments we need in our distribution system.



Ensuring that Ontario continues to have the electricity delivery system that it needs and deserves.

This year, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, expertly meeting the operational challenges posed by multiple severe storms that affected many of our customers. The company embarked on several large projects to ensure the delivery of safe, reliable electricity to the people of Ontario.

The company's net income in 2006 decreased by \$28 million, or 6%, to \$455 million compared to 2005. This decrease primarily reflects increased expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, and lower transmission tariff revenues resulting from lower demand and changes to transmission regulations.

As Chair of Hydro One, I understand that the good governance of Hydro One is essential to our shareholder, the Province of Ontario, our bond holders and the people of Ontario who depend upon Hydro One's electricity delivery system. Hydro One was focused on new securities regulations this year and is now fully compliant with the strict new financial control and disclosure requirements.

We take our financial obligations seriously and our financial controls and disclosure practices are solid and undergo regular external scrutiny. We operate in a highly transparent manner. Hydro One has embraced all 13 recommendations of Ontario's Auditor General to improve compliance with our internal policies and procedures.

Hydro One made critical investments both in transmission and in distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Hydro One spent \$1.7 billion in 2006 in total capital and operation, maintenance and administrative expenditures.

Our ability to arrange sufficient and cost-effective financing supports our improving long-term credit rating. This is vital to our ability to refinance maturing debt, fund capital expenditures and address other requirements. In particular, Hydro One has access to long-term funding that better matches our debt to our long-lived assets. The upgrades to our credit ratings reflect the confidence of the rating agencies and investors in the performance and management of the company.

The Board expects continued strong, stable financial performance and is confident in the management team's ability to meet the challenges in the coming year. In the past two years Hydro One has begun a major new construction phase and this will continue in the years ahead. Major projects vital to the economic well-being of Ontario are underway, including a new interconnection with Quebec, transmission upgrades in Toronto and the connection of new sources of generation as they become available across Ontario.

Hydro One paid its shareholder, the Province of Ontario, dividends of \$350 million. Hydro One recorded \$179 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province.

On behalf of the Board of Directors, I would like to thank Hydro One's management and employees for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.



A handwritten signature in black ink, reading "R. Burak".

Rita Burak
Chair

Our work is complex, but the reason we do it is simple: Ontario depends upon Hydro One to deliver the electricity needed to put power to work.

Hydro One exists to ensure that the people, businesses, industries and communities of Ontario have the electricity they need to put power to work for them. Our transmission system represents more than 96% of Ontario's capacity.

We understand that our customers and other stakeholders expect Hydro One to be managed in a responsible manner, respecting the public trust placed in us to ensure the safe and reliable delivery of electricity at reasonable cost.

We take this trust seriously and believe that our performance and achievements of this past year bear this out.

Serving our customers drives everything we do. And our customers are diverse. From industrial giants like mining company Inco, Ontario's largest electricity consumer, to greenhouse operations in Leamington, to summer camps in Deep River and family homes in every corner of the province, we deliver electricity to a wide range of consumers.

In 2006, our customers told us that our service was better than ever. We made an honest appraisal of how we could do a better job of meeting our customers' needs, which enabled us to make major advances in improving our relationships. We have seen double-digit increases in customer satisfaction levels and we aim to reach customer satisfaction levels of 90%, on average, across all customer segments.

NERC gave our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The report singled out our industry-leading physical security procedures, infrastructure and program management as well as our innovative and fully integrated, multi-functional communications system.

We became the first utility based outside of the United States to receive the prestigious Edison Electric Institute *Emergency Recovery Award* recognizing the company's outstanding efforts in restoring power to more than 400,000 customers following three severe storms.

Our financial performance in 2006 was strong, with a net income of \$455 million, and we paid our shareholder a healthy dividend.

As stewards of this province's massive and complex electricity transmission and delivery systems, we made significant progress on a number of critical system investment initiatives. We signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems. This \$124 million investment will add an important new connection between the two grids and increase Ontario's ability to access electricity generated through renewable resources.

In November 2006, construction crews restored the Ontario to Michigan interconnection in the Sarnia area with the transmission operator in Michigan. This interconnection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of the existing high-voltage transmission system. This circuit will increase our import and export capacity by about 400MW and 200MW respectively.

We completed the excavation of a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative \$45 million investment will carry an array of electricity transmission lines to tie the east and west sides of the city together with minimal disruption. This work will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

In 2006, we launched several new conservation and demand management programs in line with the Province's goal to create a culture of conservation in Ontario. Our programs mirror our customer base; some help Ontario families save electricity and money, while others use innovative technology to allow our larger customers to ease strain on the provincial electricity grid during peak demand periods.

While we're proud of our accomplishments, our main focus is on the challenges facing Ontario's electricity transmission system. Meeting these challenges by constructing the necessary transmission infrastructure will require cooperation with all of our stakeholders.

As guardians of the province's electricity transmission system, we have a number of key investment initiatives that require our utmost attention in the year ahead. Most significant of those initiatives is the proposed construction of a new 500-kV transmission line to deliver additional electricity to southern Ontario. We are undertaking consultations with the public and other interested groups about the routing of the line as well as its benefits and impacts.

We will continue to seek approvals for a number of other major projects which are geared to improving the reliability of supply to local areas within Ontario.

My management team and I will continue to ensure that Hydro One works efficiently, effectively and in the best interests of the people of Ontario. I am enthusiastic about the challenges that lie ahead of us and proud of our record of past achievements.

I'd like to thank Hydro One's employees for working safely and with the utmost commitment to our customers. We rely on the work our employees do every day to make sure that the people of Ontario can put power to work.



Laura Formusa
President and Chief Executive Officer (Acting)

Stephanie Oatway, Energy Analyst, CVRD Inco, Sudbury

Power on demand

“Power is useless unless it is there when you need it. That is why reliable transmission is so critical to our business,” says Stephanie Oatway, Energy Analyst, CVRD Inco.

When Ontario’s largest single-point electricity user speaks, Hydro One listens. Every year Inco’s Ontario operations represent about $\frac{3}{4}$ of 1% of Ontario’s total electricity consumption. How much is that? 1,400 Gigawatt hours, enough to power a city the size of Barrie.

While Inco generates about 20% of the electricity that it needs, it depends on the reliability of Hydro One’s transmission system to keep it operating safely and profitably. With as many as 2,000 people working as far as two kilometres underground, having a secure, stable source of electricity is a serious matter.

And with today’s on-demand supply management systems and the booming nickel market, losing time to electricity failures is unacceptable.

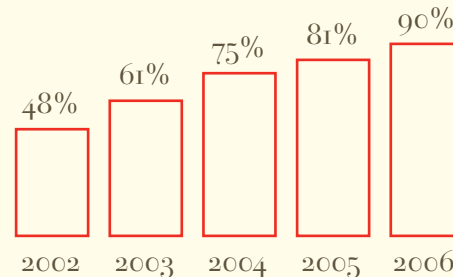
Stephanie Oatway is responsible for making sure Inco has the electricity it needs to produce the 275 million pounds of nickel per year plus copper and other precious metals. As a representative of our largest customer, she is in constant contact with Hydro One to make sure we deliver on our promises.

Last year our customers, big and small, told us we were doing better than ever on communicating and meeting our commitments to them.

275
MILLION POUNDS,

the amount of nickel Inco’s Sudbury operations produce per year.

Large Industrial Customer Satisfaction



Customer satisfaction continued to climb in 2006, with 86% of our Large Transmission Customers saying they were satisfied with our level of service. This is a 4% increase from last year and is moving steadily towards our goal of 90% customer satisfaction. Our Large Industrial Customer satisfaction improved 11% this year, hitting the 90% mark.

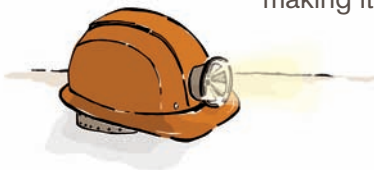
Transmission reliability is a big reason our customers are more satisfied than ever before. The North American Electric Reliability Council awarded our transmission operations facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario’s electricity transmission system. NERC’s extensive audit singled out our industry-leading physical security procedures, infrastructure and communication systems.

Hydro One’s senior management team devotes time and energy to getting to know our Large Customers’ businesses. Each member of the senior management team has direct relationships with our customers. They meet on a regular basis and are available any time if a customer has a question or an issue.

“Hydro One’s people have taken the time to understand our business and they know what’s at stake for us. They get it,” Oatway says.



Inco uses **1,400** Gigawatt hours of electricity per year to power its operations –
making it Ontario's largest single-point user.



The buzz of camp

Shortly after dinner on July 17, dark clouds filled the sky over Camp Lau-Ren on the edge of the Ottawa River.

“The winds came right through the camp toppling trees and knocking down power lines. It was a matter of seconds and the power was out,” says Nicky Nel, a volunteer counsellor for the last 15 years with Camp Lau-Ren. “We rushed around and made sure everyone was safe and after it was all done our first question was, ‘Can camp happen without electricity?’”

The campers at Camp Lau-Ren weren’t the only people asking that question.

Across Ontario, 170,000 Hydro One customers lost electricity. With tens of thousands of trees down, more than a thousand power poles broken and hundreds of kilometres of electricity line buried beneath trees snapped like matchsticks, it was the worst damage we’d seen since the 1998 Ice Storm. It would be more than a week until everyone had their power back on.

120 KM/h

winds during three major storms and eight tornadoes pounded Ontario in the summer of 2006.

Hydro One responded to this storm by mobilizing our highly trained workforce, bringing in partners from other utilities and working long days to safely return electricity service to our customers. Our fleet of helicopters filled the sky and crews worked tirelessly to rebuild Ontario’s electricity delivery system. In the first 24 hours, we restored electricity to 90,000 of the customers that had been affected.

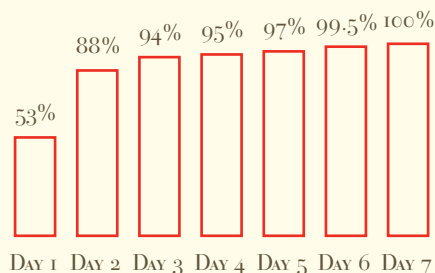
For our work on this storm and two others in a two-month period, the Edison Electric Institute awarded Hydro One the *Emergency Recovery Award*, the first time this honour has been bestowed on a utility based outside of the United States.

While recognition from our peers as one of the best in the business at storm recovery means a lot, it pales in comparison to the way our customers responded. After four days of sharing two outhouses between 60 people, with no electricity, no flush toilets, no electric lights and no running water, Hydro One trucks were treated to a hero’s welcome when they finally pulled into Lau-Ren.

“When we saw the trucks, we knew Hydro One had reached us,” Nicky says. “The campers were yelling and greeting them with signs. It was a great moment. I think for a lot of the campers, they had a whole new appreciation for electricity.”

Storm Recovery

(Percentage of 170,000 affected customers restored)





Hydro One deployed more than **1,000** workers, who worked
16-hour days to restore electricity and repair the worst damage
since the **1998** Ice Storm.



Cole Cacciavillani of CF Group Greenhouses, Leamington

Green power blooms

Keeping a greenhouse's climate at the perfect temperature and humidity depends upon electricity. The summer heat inside the greenhouse is so great that without the electric fans, the plants would never survive to bloom. During Ontario's coldest months, without electricity there'd be no flowers for Valentine's Day.

Backup electricity generation for Ontario's greenhouse industry is truly a matter of life and death.

"If we lose power, we're out of business," says Cole Cacciavillani, whose father Floyd started the family business with a single greenhouse in the 1950s.

In the last decade, CF Group Greenhouses (CF Group) has grown enough potted plants to cover Ontario. It's also developed generator technology to help greenhouses and other critical electricity users meet their own urgent power needs.

"All greenhouses invest in backup generation, but we only need it in emergencies. With help from Hydro One, we've connected that generation to the grid to put it to work for the rest of Ontario," says Cacciavillani.

Working with Hydro One, Cacciavillani has connected close to 4 MW of power that Ontario can call on when it needs more supply. The connection contributes to Ontario's supply reliability, takes stress off of Hydro One's transmission system and helps Ontario greenhouses turn a backup system into an asset.

880,000

Number of our customers who participated in one of our conservation and demand management programs.

Ontario's greenhouses not only contribute about \$2 billion a year to the province's economy, the network of generators managed by the CF Group and connected to Hydro One's grid now contributes about 4 MW of electricity, enough to power 1,300 homes.

Finding new ways for customers to use electricity wisely is the goal of Hydro One's Conservation and Demand Management group. In 2006, Hydro One not only helped enterprises like greenhouses and wind farms connect to the grid, we worked with our approximately 1.3 million residential customers to reduce peak demand.

Programs like SmartStat, the PowerCost Monitor and Appliance Retirement made a concrete difference to the amount of electricity Hydro One customers used. Our team removed more than 4,000 energy-hogging refrigerators from the grid. Our PowerSaver tour, in conjunction with Home Depot, travelled the province and provided customers with vital information on ways to reduce electricity usage and offered advice on energy efficient products.

By working together and encouraging innovation, Hydro One and Ontario energy users and generators can meet future challenges.

4,000

Number of old, energy-sapping refrigerators, freezers and room air conditioners collected from our customers.



Hydro One helped CF Group Greenhouses connect about **4 MW** of electricity to the grid, enough to power about 1,300 homes in times of short supply.



accomplishments



In 2006, Hydro One completed digging a 2.2-kilometre tunnel beneath the streets of Toronto. This innovative project will carry an array of electricity transmission lines to tie the east and west halves of the city together, with minimal disruption to traffic or residents. Expanding the links between east and west by running new transmission lines through the \$45 million investment will let power flow more freely across the city, giving Toronto increased flexibility, reliability and supply.

The project is scheduled for completion late next year with the new 230-kV circuit expected to be operational by early 2008.

Hydro One has signed an agreement with Hydro-Québec TransÉnergie Inc. for construction of state-of-the-art power transmission equipment including new circuits across the Ottawa River connecting the two provincial high-voltage power systems.

The \$124 million investment for Hydro One will add an important new connection between the two grids. The first phase of the project – the new connection with Ontario – will come into service in early 2009, and will have a capacity of 900 MW. The second phase – the addition of a reinforcement line – will be brought into service in the spring of 2010, and will increase the connection's capacity to 1,250 MW.

Highly Rated

Dominion Bond Rating Service raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. In addition, our short-term debt rating was upgraded to R-1 (middle) from R-1 (low).

Construction crews rebuilt the interconnection in the Sarnia area with the transmission operator in Michigan. This connection improves overall supply reliability in Ontario by increasing electricity import/export capacity and maximizes the effectiveness of our existing high-voltage transmission system.





Hydro One is reinforcing the high-voltage transmission system in the Niagara region which will help significantly in meeting electricity needs in Southern Ontario during high-demand periods.

These upgrades will increase power import capacity from New York State up to 800 megawatts – enough power to meet the needs of about 260,000 homes – and accommodate additional power supplied by Ontario Power Generation's Sir Adam Beck stations after completion of a third tunnel at Niagara Falls.

In August, the Kleinburg Training Centre opened its doors to teach Ontario's future electricity workers.

The need for the facility was clear with the number of apprentices needing training doubling from 176 in 2003 to close to 400 in 2006.

This facility allows us to give the next generation of line maintainers, meter readers, distribution technicians, protection and control trainees hands-on experience in a safe environment.

The centre not only provides vital training to Hydro One apprentices, it's a Ministry of Training, Colleges and Universities certified facility. Apprentices from utilities across the province come here to put spurs on for the first time and take those tentative first steps up a wooden pole.

Close to
100
MILLION kWh,

enough electricity to power 8,200 homes for one year, were saved by Hydro One's customers through our conservation and demand management programs.



Customers told us the old system for checking outages on our website was cumbersome, so we improved it. Our redesigned online Power Outage Notification system improves communications between Hydro One and the public and provides real-time information to the media during major storms or other outage situations. The new system paints a very accurate picture of the status of our electricity transmission and distribution system.

\$807,728

was raised by Hydro One employees for charities of their choice in 2006.

Hydro One Senior Management



Laura Formusa
President and Chief Executive Officer
(Acting)
Hydro One Inc.



Joe Agostino
General Counsel
(Acting)



Myles D'Arcey
Senior Vice-president,
Customer Operations



Steve Dorey
Vice-president,
External Relations



John Fraser
Vice-president, Internal Audit
and Chief Risk Officer



Tom Goldie
Senior Vice-president,
Corporate Services



Peter Gregg
Vice-president,
Corporate and Regulatory Affairs
and Executive Office



Rick Kellestine
Vice-president,
Culture



Naim McQueen
Vice-president,
Engineering and
Construction Services



Geoff Ogram
Vice-president,
Asset Management



Wayne Smith
Vice-president,
Grid Operations



Beth Summers
Chief Financial Officer

Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2006 and 2005.

Overview

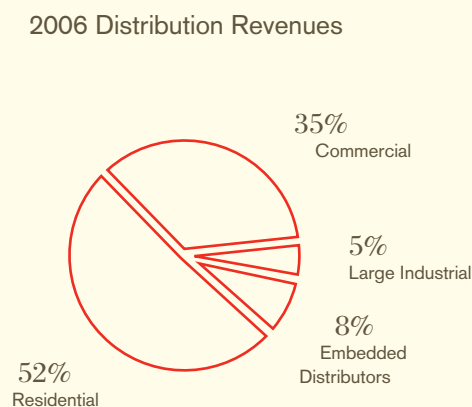
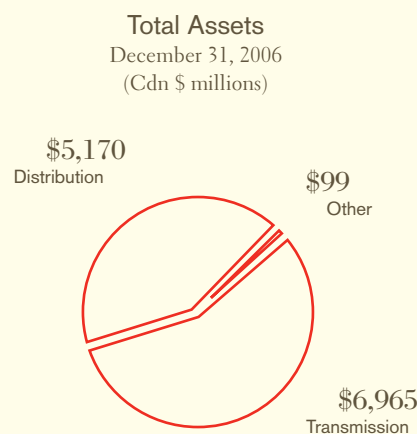
We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2006, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2006, we earned total transmission revenues of \$1,245 million primarily by transmitting approximately 151 TWh of electricity, directly or indirectly, to more than 4 million customers. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our transmission business is our largest segment, representing approximately 60% of our total assets.

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 48 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, over half of our distribution revenues are earned from our residential customers.



Other

Our other business segment contributed revenues of \$27 million in 2006 and has assets of about \$99 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2006, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value, while striving to attract, develop and retain productive employees.

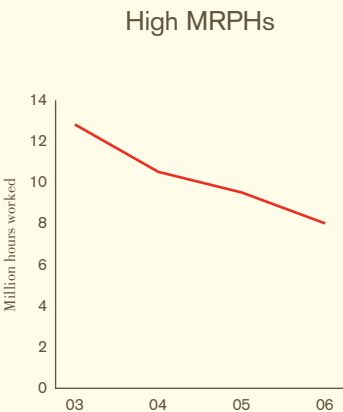
We seek to achieve these goals by continuing to implement the following strategies:

- *Safety*: Create and maintain an injury-free workplace with a concentrated focus on elimination of serious injury and “near misses” in high potential harm categories of work.
- *Customers*: Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers’ level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.
- *Reliability*: Enhance the reliability of our transmission and distribution systems. In transmission, we have assumed a proactive leadership role in developing the system to meet Ontario’s power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.
- *Financial*: Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.
- *Employees*: Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We substantially met or exceeded our challenging 2006 objectives, improving in a number of areas over 2005, and are moving towards achieving our strategic goals.

The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to achieve a record of no serious injuries and no serious near misses. Accordingly, we measure our high Maximum Reasonable Potential for Harm (MRPH) incidents rate to identify possible problems or situations that may increase the risk of injury. As shown in the accompanying chart, we had eight high MRPH incidents per million hours worked in 2006, which is 16% lower than 2005, 24% lower than 2004, and 38% lower than 2003.



We also maintain our focus on serious incidents in high risk areas including electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. The number of serious incidents declined from about nine incidents per million hours worked in 2003, to approximately five in 2006. Going forward, we will continue to stress the importance of safety through a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments, development of a learning management system and further use of decision analysis tools to reduce human error and its consequences.

Customer satisfaction is also vital to our success. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 83% to 86% satisfied as compared to 2005. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our Residential and Small Business Customers and survey results show an increase in the level of satisfaction to 83% satisfied from 81% last year. While our 2006 Generator satisfaction level of 74% was acceptable, it was slightly below our annual target, and addressing the concerns identified will be an area of focus in 2007. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

Weather patterns and generation constraints require exemplary performance from both our transmission and our distribution systems. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2006, we met our annual reliability targets and achieved some improvements over 2005. We did so while managing the impacts of a number of devastating storms throughout the year, including the back-to-back storms experienced over the summer. We enhanced our storm response and communication, including improving processes, improving our website and providing “real time” information through emails and faxes. Subsequent to year end, the Edison Electric Institute (EEI) honoured us with an emergency recovery award for our outstanding efforts to restore electricity service during these storms. This is the first time this prestigious award has been won by a utility outside of the U.S.

Meeting our shareholder requirements is an integral part of our business focus. Strong financial performance was again characterized by our 2006 results and we maintained or improved credit ratings on both our short-term and long-term debt. On June 23, 2006, Dominion Bond Rating Service Inc. raised our short-term debt rating to R-1 (middle) and our long-term debt rating to A (high), as a result of key factors including their expectation that our financial profile will remain strong over the medium to long term.

Regulation

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). The OEB sets prices at least every 12 months, or more frequently, and may upon review, reset prices over the next 12 months to better reflect the cost of supply. The OEB currently plans to review the need to reset prices every six months. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and to assist with the stability of rates for RPP customers, among others. As part of its mandate to ensure the adequate long-term supply of electricity, and consistent with the Province's direction regarding supply mix, the OPA is in the process of developing the Integrated Power System Plan (IPSP), which must be submitted for review and approval to the OEB which will conduct public hearings and consultation. The OPA currently expects to submit the IPSP to the OEB in March 2007. As part of the IPSP process, the OPA has issued a number of discussion papers for comment by stakeholders. Of the papers issued to date, two are most important to the transmission business and influence our capital expenditures; "Discussion Paper 5 – Transmission" and "Discussion Paper 7: Integrating the Elements – A Preliminary Plan" (See "Future Capital Expenditures" on page 29).

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination will further initiatives undertaken by individual local distribution companies (LDCs), including our distribution business, as a result of distribution rate increases approved in 2005. Some of the funds associated with this increase were required to be used on CDM programs. Our programs amounted to approximately \$43 million over the period 2005 to 2007, consistent with this direction. The overall goal of the CDM programs is to reduce provincial demand by 6,300 MW by 2025. The OPA issued "Discussion Paper 3 – Conservation & Demand Management" and is expected to submit a CDM plan as part of the IPSP.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely and providing customers with access to information about their consumption. A new entity will oversee the communications systems and technologies, collect and manage data, and facilitate meter procurement. LDCs, including our distribution businesses, will own, install, operate and maintain their own meters. We are currently deploying smart meters under our program (See "Future Capital Expenditures" on page 29).

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. In 2000, the OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks), seeking approval of a revenue requirement of \$1,263 million for 2007 and \$1,298 million for 2008, subject to minor updates in the normal course. This application is based on achieving a 10.5% return on equity and an increase in the common equity component of the capital structure from 36% to 40%. The proposed rate increases are 4.3% in 2007 and 2.7% in 2008, with the impact on an average customer's total bill estimated to be less than 0.5% in both years. Consistent with the OPA discussion papers, the application includes funding to enable new generation and ensure the adequacy of area supply, as well as the continued reliability of aging transmission assets. We believe the proposed regulated return, in conjunction with capital structure, supports the financial metrics underlying an A credit rating category, facilitating access to capital markets at reasonable rates.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue decreased by approximately \$13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates were initially approved by the OEB in 2000 to provide for cost recovery and a return on deemed common equity targeted to be 9.88%. Related distribution rate increases were phased in over a number of years, with the final installment approved by the OEB in March 2005. In August 2005, we filed a distribution rate application seeking approval for a \$160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. On April 12, 2006, the OEB announced its decisions regarding this application and that of our distribution business conducted by Hydro One Brampton Networks Inc. (Hydro One Brampton). On the basis of the written and oral evidence submitted, the OEB approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

While current distribution rates are based on a cost of service rate regulation model, the OEB is in the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007–2010. Consistent with OEB guidelines, we plan to apply for distribution rate adjustments in February 2007, with minimal impact anticipated on the total customer bill. This application is based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management.

On March 21, 2006, the OEB approved a monthly rate of 30 cents per residential customer, effective May 1, 2006, as initial funding for the required investment in smart meters. The distribution rate application, to be filed with the OEB in February 2007, will include a request to increase this level of smart meter funding. Expenditures in excess of recoveries are currently being recorded as a regulatory asset, with disposition to be established at a later date.

Results of Operations

Revenues

Year ended December 31

(Canadian dollars in millions)

	2006	2005	\$ Change	% Change
Transmission	1,245	1,310	(65)	(5)
Distribution	3,273	3,085	188	6
Other	27	21	6	29
	4,545	4,416	129	3
Average annual Ontario 60-minute peak demand (MW) ¹	22,650	23,074	(424)	(2)
Distribution – units distributed to customers (TWh) ¹	29.0	29.7	(0.7)	(2)

¹ System-related statistics include preliminary figures for December.

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Transmission revenues decreased by \$65 million, or 5% in 2006, compared to last year, reflecting two recent OEB decisions. On February 21, 2006, the OEB applied an earnings sharing mechanism to any transmission earnings in excess of our approved rate of return of 9.88% for the period January 1, 2006 until new rates are set. Consequently, 50% of excess earnings recovered from customers are deferred as a regulatory liability. This decision had the effect of reducing transmission revenues by \$33 million for the year. On December 8, 2005, the OEB adjusted revenue allocation factors for all of the Province's electricity transmitters, reducing 2006 transmission revenues by \$13 million.

In addition, 2006 monthly peak demands were generally lower than last year. While there were a few exceptions, notably the all-time record peak demand of 27,005 MW set on August 1 and the May record peak demand of 24,857 MW, our average annual Ontario 60-minute peak demand was 424 MW lower and the overall related load was 5,083 MW lower than last year, resulting in lower revenues of \$26 million. The impact of these reductions was partially offset by a marginal increase in ancillary revenues related to revenues earned from the secondary use of our land rights-of-way.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by our distribution rates, the amount of electricity we distribute and the cost of purchased power. Distribution revenues also include minor ancillary services revenues, such as rental fees charged to telecommunications and cable television companies for the use of our poles, and miscellaneous charges such as those made for late payments.

Distribution revenues increased by \$188 million, or 6%, in 2006 compared to last year, primarily as a result of two OEB-approved distribution tariff rate increases that became effective April 1, 2005 and May 1, 2006. The April 1, 2005 increase was originally scheduled to be effective March 1, 2003, and was subsequently suspended for all LDCs by the *Electricity Pricing Conservation and Supply Act, 2002*. On April 12, 2006, after reviewing our evidence, the OEB approved increases in distribution tariff rates for our distribution businesses conducted by Hydro One Networks and Hydro One Brampton, effective on May 1, 2006. We also received OEB approval for low-voltage rates for services provided to LDCs that are embedded within our service territory. These tariff rate increases support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, and resulted in higher distribution revenues of \$105 million compared to last year.

Distribution revenues also include the recovery of increased purchased power costs of \$90 million, as described below under “Purchased Power.” The impact of the increases in tariff rates and purchased power costs was partially offset by lower distribution tariff revenues of \$5 million associated with lower demand, as well as marginally lower ancillary revenues.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory. These costs consist of the wholesale commodity cost of electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. From April 1, 2004 to March 31, 2005, for certain low-volume and designated customers, the commodity price of electricity was based on an interim two-tiered pricing structure. This structure was subsequently replaced by the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP continue to pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the interim pricing plan and RPP affecting the two-year period 2005 and 2006 is provided below.

Summary of Interim Pricing Plan & RPP

Price Plan	Effective Date	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
		Residential	Non-Residential	First Tier	Second Tier
Interim	April 1, 2004	750	750	4.7	5.5
RPP	April 1, 2005	750	750	5.0	5.8
RPP	November 1, 2005	1,000	750	5.0	5.8
RPP	May 1, 2006	600	750	5.8	6.7
RPP	November 1, 2006	1,000	750	5.5	6.4

Purchased power costs increased in 2006 by \$90 million, or 4%, to \$2,221 million compared to last year. Our increased purchased power costs were primarily due to higher costs of \$189 million associated with the OEB's RPP for residential and other eligible customers, combined with the 2005 impact of providing the *Ontario Price Credit* to RPP customers in accordance with a regulation issued in October 2005. This \$140 million credit was provided to RPP customers in 2005 to recognize a lower cost of power than the fixed commodity price for the period April 1, 2004 to March 31, 2005. These increases were partially offset by lower wholesale commodity prices of \$137 million for customers who are not eligible for the RPP, and lower wholesale market service charges levied by the IESO of \$55 million. The remaining \$47 million reduction was due to a lower demand for electricity.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31

(Canadian dollars in millions)

	2006	2005	\$ Change	% Change
Transmission	390	353	37	10
Distribution	460	413	47	11
Other	30	26	4	15
	880	792	88	11

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by \$37 million, or 10%, in 2006 compared to last year. Within our work programs, we continued to make the investments necessary to ensure the safe and reliable operation of our installed transmission system, with particular focus on the assets that are critical to generation and to the unrestricted supply of electricity to our customers. We experienced increased work program requirements of approximately \$32 million this year, primarily related to increased station maintenance expenditures, including our focus on our 750 MVA autotransformers, higher employee benefit costs attributable to a lower discount rate for actuarially determined benefit costs, economic increases in materials and fuel costs and the impact of a labour disruption in 2005. Other support costs increased marginally by \$5 million in 2006 compared to the previous year. Higher information technology requirements this year, combined with the impact of last year's recoveries associated with insurance settlements and bad debt recoveries, were substantially offset by this year's cost reduction associated with a negotiated property tax settlement.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by \$47 million, or 11%, compared to last year. We experienced increased work program requirements of approximately \$50 million, primarily within our lines and customer care work programs. These increases reflect our recovery efforts following a series of destructive storms, particularly in the third quarter. In 2006, we experienced 10 significant storm events, compared to 4 in 2005. Consequently, our storm-related repair and maintenance expenditures for our distribution business increased by approximately \$13 million to \$21 million. In addition, our annual work program expenditures were impacted by higher fuel costs, the same economic increases that we experienced within our transmission business, and the effects of last year's labour disruption. Other costs incurred to support our distribution work programs declined by about \$3 million, primarily as a result of our reassignment of resources to support our larger capital program this year, partially offset by the impact of higher information technology requirements.

Depreciation and Amortization

Depreciation and amortization expense increased by \$28 million, or 6%, to \$515 million this year. Depreciation expense was higher by \$10 million relative to 2005, primarily as a result of the placement of new assets in service, consistent with our ongoing capital work program. Year-over-year, amortization of regulatory and other assets increased by \$18 million. This increase was attributable to increased amortization of our regulatory assets as a result of the OEB's April 12, 2006 decision to approve recovery of certain regulatory assets.

Financing Charges

Financing charges declined by \$30 million, or 9%, to \$295 million compared to last year. Approximately \$25 million of this decrease was due to a lower average effective interest rate on our outstanding long-term debt. In addition, we capitalized approximately \$5 million more interest this year, primarily as a result of a higher level of capital expenditures.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes declined by \$19 million, or 10%, to \$179 million in 2006 compared to 2005. Approximately \$17 million of this reduction was due to this year's lower taxable income. The tax benefit of approximately \$30 million that was recognized in the first quarter of 2006 pertaining to the recovery of prior years' corporate income taxes, was partially offset by the impact of last year's second quarter tax benefit in the amount of \$21 million, which pertained to prior period tax losses of one of our subsidiaries. Payments in lieu of corporate income taxes were also reduced by tax changes enacted in the second quarter of 2006 relating to the elimination of the federal large corporations tax and higher capital cost allowance rates. These impacts were partially offset by taxes payable on transmission amounts received but not recognized for accounting purposes, primarily due to the OEB's earnings sharing mechanism.

Net Income

Net income of \$455 million was lower by \$28 million, or 6%, compared to 2005 results. Our net income for the year reflects higher expenditures required to operate and maintain our transmission and distribution systems, particularly as a result of the damaging storms we experienced this year, combined with lower transmission tariff revenues resulting from lower demand and the effects of the OEB's earnings sharing mechanism. The impact of these factors was partially offset by higher distribution tariff revenues associated with OEB-approved tariff rate increases and a marginal reduction in our effective tax rate. This tax rate reduction primarily resulted from the relative sizes of the tax benefits recognized in the first quarter of 2006 and in the second quarter of 2005.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2005 through December 31, 2006. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)					2006				2005
Quarter ended	Dec. 31	Sep. 30	Jun. 30	Mar. 31	Dec. 31	Sep. 30	Jun. 30	Mar. 31	
Total revenues ^{1,2}	1,142	1,165	1,078	1,160	1,025	1,179	1,018	1,194	
Net income ^{1,2}	101	103	99	152	104	133	115	131	
Net income to common shareholder ^{1,2}	96	99	94	148	99	129	110	127	

¹ The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

² Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately \$140 million. The application of the one-time credit did not result in any adjustment to net income.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Investing activities		
Capital expenditures	(823)	(691)
Other financing and investing activities	11	1
Net change in cash and cash equivalents	(20)	–

Operating Activities

Net cash from operating activities decreased by \$273 million to \$896 million, compared to 2005 results. This reduction primarily reflects the impact on our working capital requirements of providing RPP customers with the \$140 million *Ontario Price Credit* early in 2006, funding for which was received by us from the IESO in late 2005. Our working capital requirements were also impacted by higher electricity prices charged to RPP customers in 2006, changes in the timing of tax payments and changes in trade accounts payable balances related to our work programs.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to \$1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a \$750 million committed revolving credit facility with a syndicate of banks which matures in August 2007 and which has a two-year extension option. As at December 31, 2006, we had \$60 million in short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2006, we had \$5,270 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is \$2,500 million, of which \$1,725 million is remaining and is currently available until July 2007.

During 2006, Dominion Bond Rating Service Inc. raised our long-term debt rating to A (high), with a stable trend, from A with a positive trend. Our short-term debt rating was upgraded to R-1 (middle) from R-1 (low). Our credit ratings are:

Rating Agency	Rating	
	Short-term Debt	Long-term Debt
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement that supports our \$750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2006, we issued \$775 million in long-term debt under our medium-term note program and we repaid \$589 million in maturing long-term debt. In comparison, during 2005 we issued \$500 million in debt under our medium-term note program and we repaid \$648 million in maturing long-term debt. In 2006, we increased our short-term notes by \$60 million compared to a reduction of \$40 million in 2005.

In 2006, we paid dividends to the Province in the amount of \$350 million, consisting of \$332 million in common dividends and \$18 million in preferred dividends. In the comparative period, we paid common dividends of \$273 million and preferred dividends of \$18 million. In 2006, cash dividends per common share were \$3.320 compared to \$2.730 per common share in 2005. Cash dividends per preferred share were \$1.375 in both 2006 and 2005.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations, the level of net income and timing. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31

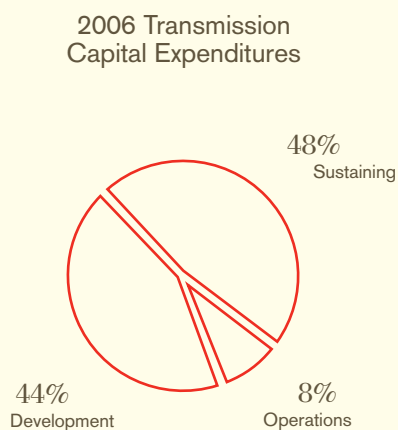
(Canadian dollars in millions)

	2006	2005	\$ Change	% Change
Transmission	402	349	53	15
Distribution	417	338	79	23
Other	4	4	–	–
	823	691	132	19

Transmission

Transmission capital expenditures increased by \$53 million in 2006 to \$402 million, compared to 2005. Expenditures to expand and reinforce the transmission system were \$179 million, \$54 million higher than last year. These increased development investments primarily reflect higher required generation and load customer connection expenditures in this year. Our generation-related expenditures included a major reconfiguration of our Lambton Transformer Station, to enable the connection of new gas-fired generation. Increased load customer connection work included construction of a new transformer station to accommodate growth in Simcoe Region and work on transformer station improvements in Durham Region. Our development expenditures also included two critical projects to improve the flow of electricity in recognition of growing needs: the Niagara Reinforcement Project, which will reinforce the transmission system in the Niagara region and provide access to new sources of generation; and our Downtown Toronto Cable Project, which involves the construction of two underground cable circuits to reinforce our electricity transmission facilities. Our Niagara Reinforcement Project is essentially complete. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area and discussions continue between the affected aboriginal peoples and the various government entities involved. Once we regain access and perform a site condition assessment, we expect project completion within six weeks. In 2005, we substantially completed construction of the Parkway Transformer Station and refurbishment of the Cooksville Transformer Station. Both projects were carried out to accommodate the closure of the Lakeview Generating Station.

Our expenditures to sustain the existing transmission system were \$192 million, representing a marginal decrease of \$1 million compared to last year. Additional sustainment expenditures were made to replace storm-damaged equipment and to purchase new transformers. The impact of these requirements, together with the impact of last year's labour disruption, were substantially offset by reduced engineering and construction expenditures related to the refurbishment and replacement of end-of-life lines, stations and telecommunications assets. Other transmission capital expenditures were \$31 million, unchanged from last year.

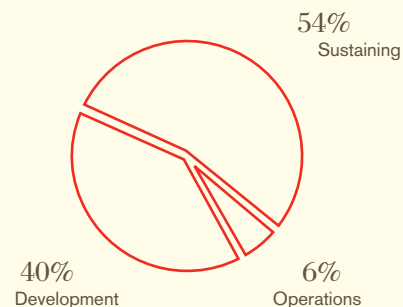


Distribution

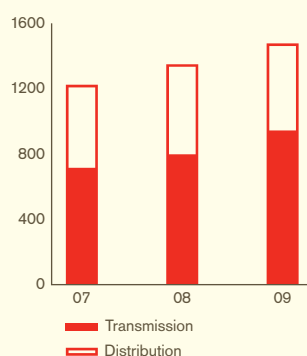
Distribution capital expenditures increased by \$79 million to \$417 million in 2006, compared to the prior year. Expenditures to sustain our low-voltage distribution system were \$225 million, an increase of \$63 million over 2005. This increase was primarily a result of higher storm-related expenditures to replace damaged assets. Year-over-year capital expenditures for storm restoration were \$62 million, an increase of \$36 million. As a result of the significant storm activity this year, we replaced more than 1,600 distribution poles and more than 200 kilometres of line. Increased sustainment expenditures also reflect higher planned replacements of end-of-life assets, unplanned asset replacements and line relocations, as well as the impact of last year's labour disruption.

Capital expenditures to expand and reinforce our distribution network were \$167 million, an increase of \$20 million compared to last year. This increase primarily reflects our deployment of smart meters during the year. Our other distribution capital expenditures decreased by \$4 million to \$25 million.

2006 Distribution Capital Expenditures



Future Capital Expenditures
(Cdn \$ millions)



Future Capital Expenditures

Our capital expenditures in 2007 are budgeted at about \$1.25 billion, an increase of over \$400 million from 2006 levels. The 2007 capital budgets for our transmission and distribution businesses are about \$700 million and \$500 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to be approximately \$1.35 billion in 2008 and \$1.5 billion in 2009, primarily reflecting increasing investments in necessary transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with the OPA's discussion papers and the needs of

our aging transmission system under continued challenging conditions of tight generation supply. These investments will facilitate an adequate and reliable supply of electricity in the public interest. The investment levels also reflect the mass deployment of smart meters within our distribution businesses beginning in 2007. The replacement of critical information technology systems is also contemplated. Capital expenditures of our other business segment are budgeted at about \$20 million in 2007, largely due to the implementation of a dedicated optical network to provide secure, high capacity connectivity across numerous health care locations in Ontario.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2007 to 2009, amounting to almost \$2.4 billion. Our investment plan will address new development and supply enhancement initiatives, including system expansion, generation requirements and load connections. The transmission program also continues the focus on “mission critical” assets, which are those assets critical to generation facilities and the unrestricted transmission of energy to our customers.

The development component of our investment plan for transmission includes enhancements to the transmission system in the Bruce Peninsula to accommodate new wind generation and redeveloped nuclear generation; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Midtown Toronto; and a new interconnection between Ontario and Quebec. Initiatives taken by the Province and the OPA have led to many new generation developments and we are undertaking investments to connect many of these to the transmission system. Major connections include large new gas generators in Sarnia, the west GTA and downtown Toronto, and several large new wind farms. Several projects have need dates that cannot be met if approvals are delayed beyond the release of the IPSP. As such, we have initiated the processes required to file Leave-to-Construct applications with the OEB and to receive other approvals as required.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Investments in mission critical assets ensure a reliable supply of energy throughout the province. Through targeted replacement programs for components such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes, continues to be essential. Examples of projects initiated to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston and Red Lake. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems will lead to improved reliability.

The timing of many development projects is uncertain as they are dependent upon the final IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Consistent with our approved 2006 distribution rate applications, capital expenditures for the period 2007 to 2009 are budgeted at approximately \$1.7 billion. This amount includes core development and sustainment work as well as our smart meter program. Our core work will focus on new load connections, trouble calls and storm damage, wood pole replacement, and system capability reinforcement. Given initiatives to encourage renewable energy technologies, we also anticipate increased connection of new generators which could trigger the need for larger system modifications.

Our distribution investment plan includes the mass rollout of the smart meter program. Over the period 2007 to 2010, we anticipate installing over 1 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately \$75 million under our smart meter program and install 240,000 meters. At the Province's request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2006

(Canadian dollars in millions)	Total	2007	2008/2009	2010/2011	After 2011
Contractual obligations (due by year):					
Short-term note payable	60	60	–	–	–
Long-term debt – principal repayments	5,270	395	900	650	3,325
Long-term debt – interest payments	4,769	291	524	448	3,506
Inergi LP (Inergi) outsourcing agreement ¹	496	110	192	178	16
Operating lease commitments	16	5	9	1	1
Total contractual obligations	10,611	861	1,625	1,277	6,848
Other commercial commitments (by year of expiry):					
Bank line ²	750	750	–	–	–
Letters of credit ³	118	118	–	–	–
Guarantees ³	275	275	–	–	–
Pension ⁴	8	8	–	–	–
Total other commercial commitments	1,151	1,151	–	–	–

¹ On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

² As a backstop to our commercial paper program, we have a \$750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2007, with a two-year extension option.

³ We currently have bank letters of credit of \$93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of \$22 million and parental guarantees of \$275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

⁴ Contributions to the pension fund are made one month in arrears. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to \$100 million.

The long-term debt amounts in the above table are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or within our capital expenditures. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our payments in lieu of corporate income taxes, which are paid or payable to the OEFC.

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices and our Chief Financial Officer for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province of Ontario

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence major business and corporate decisions. Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve potential conflicts with the Province on terms satisfactory to us.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rates of return.

On September 12, 2006, Hydro One Networks filed, with the OEB, its application and evidence in support of its 2007 and 2008 transmission revenue requirements based on a capital structure with a higher equity component and a higher return on equity. Our operation, maintenance and administration expense levels have increased over time and our transmission business rate base has increased, reflecting prudent expenditures, since transmission rates were initially established. However, there is the risk that these increases may be disallowed by the OEB. Any disallowed capital expenditures would be charged to the results of operations in the period that the OEB renders its decision. Insufficient funding for our transmission business could adversely impact our financial results and the operating performance of the transmission system.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2007, which could significantly reduce our revenues, particularly transmission. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transmission facilities by constructing their own assets under certain conditions.

There is also a risk we could be required to invest in large-scale transmission infrastructure projects, to incur unexpected capital expenditures to maintain or improve our assets, and to connect new third-party generation assets. The Province has passed regulations authorizing us to procure smart meters but we are only currently authorized to recover 30 cents of the associated costs in rates. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential charges to our results of operations.

Asset Condition

We continually maintain our assets to provide reliable service and to accommodate customer needs. However, our installed asset base is aging to the point where the assets require increased maintenance, major refurbishment or replacement. Executing these activities is also becoming more challenging as the opportunities to remove equipment from service to accommodate work are becoming increasingly limited. Consequently, we may not be able to complete the necessary repairs and replacements on a cost-effective or timely basis, which could affect transmission reliability and our ability to deliver sufficient electricity.

Risk Associated with Transmission Projects

Significant investments are needed to increase transmission capacity and enable the delivery of reliable electricity from existing and new generation sources to Ontario consumers. These investments are, in most cases, subject to OEB approvals, which can include expropriation, and where required, environmental approvals and consultation and possibly accommodation with First Nations. The ability to make such investments may also be impacted by public opposition. If we are unable to make these necessary investments, the reliability of our transmission system and our ability to deliver sufficient electricity could be materially adversely affected.

Work Force Demographic Risk

Approximately 25% of our employees will be eligible for retirement by 2008. We expect the skilled labour market for our industry to remain highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union or the Society of Energy Professionals. Existing collective agreements with the Power Workers' Union and the Society of Energy Professionals expire on March 31, 2008. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). It is expected that these draft regulations will be finalized later in 2007. We have estimated the non-capital expenditures for complying with these draft regulations to be between \$250 million and \$375 million in excess of amounts we have already recorded as environmental liabilities on our balance sheet. If required, most of these additional expenditures would be incurred in the 2013 to 2025 period. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to withstand such occurrences, our facilities may not do so in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2007 and 2010. We also plan to incur total capital expenditures of approximately \$1.25 billion in 2007 and \$1.35 billion in 2008. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and our future capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The next valuation will be prepared as at December 31, 2006 and must be filed on or before September 30, 2007. The required level of contributions effective January 1, 2007 will depend on future investment returns, changes in benefits, and changes in actuarial assumptions. Based on current factors, we estimate annual pension contributions for 2007 and beyond to be up to \$100 million per annum. Pension costs are subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately \$850,000 per year that we are currently paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have an adverse effect on our results of operations if we are unable to recover them in future rate orders.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors in conjunction with the operation of our systems may increase safety or environmental risks.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, capture data and produce timely and accurate information used in our business. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing our operating costs, in 2002 we entered into an outsourcing services agreement with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have an adverse effect on our results of operations.

Market and Credit Risk

Market risk refers primarily to risk of loss related to changes in commodity prices, foreign exchange and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2007 and 2008 would have an impact on net income of approximately \$2 million and \$4 million, respectively. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of \$40 million and an insignificant fair value.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2006 amounted to \$311 million and principally relate to the regulatory asset recovery accounts (RARAs), employee future benefits other than pension, environmental costs, and expenditures associated with the smart meter program. We have also recorded regulatory liabilities amounting to \$473 million as at December 31, 2006. These amounts pertain primarily to pension, export and wheeling fees, and the transmission earnings sharing mechanism. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARAs, or if future OEB direction is judged to be probable. Most of our regulatory assets have been reviewed by the OEB and confirmed as recoverable.

To date, our smart meter expenditures and recoveries have been recorded in regulatory asset accounts consistent with OEB guidance. The timing and amount of inclusion of these amounts in our Statement of Operations is currently uncertain and will depend on future OEB decisions as well as other factors.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related assets for the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our demerger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing the work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of 2% has been used to express current cost estimates as future expenditures. These expenditure amounts have been discounted using a factor of 6.25%. Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or whenever significant changes in regulation occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately \$80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets exceeded this long-term assumption in 2006.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2006 increased by 0.25% from those at December 31, 2005 in conjunction with increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about \$13 million per year.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2006 and we determined that the carrying value of our goodwill has not been impaired.

Emerging Accounting Pronouncements

Transition to International Financial Reporting Standards (IFRS)

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over a five-year transitional period. The AcSB published an updated detailed implementation plan for achieving convergence in June 2006. The plan calls for the first year of reporting under IFRS to be 2011. At that point, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we began our transition preparations in 2006.

Accounting for Rate-Regulated Operations

Following the approval of its new strategic plan to adopt IFRS, the AcSB revisited the scope of its project on rate-regulated accounting in recognition of the fact that IFRS does not currently provide any special accounting treatment for rate-regulated enterprises. As a result, the AcSB is expected to issue an exposure draft in early 2007 to propose removal of all specific references to rate-regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). It is expected that the AcSB will allow qualifying enterprises to apply the relevant U.S. accounting standard, Statement of Financial Accounting Standard 71 *Accounting for the Effects of Certain Types of Rate Regulation* (SFAS 71). Enterprises subject to rate regulation will be qualified to use SFAS 71 as long as they meet the specific criteria found in that accounting standard and as long as they apply it in the manner the U.S. standard setter intended. We believe our company meets these criteria. The future application of SFAS 71 will have an impact on our financial statements. Accrual accounting practices will be followed for payments in lieu of corporate taxes, which are currently accounted for on a cash basis as a result of specific OEB direction. The difference between the accrual and cash basis will be reflected through the recognition of additional regulatory assets and, consequently, the impact on our results of operations is expected to be minimal.

Financial Instruments

In 2005, the CICA issued new accounting standards comprising Handbook Section 3855, *Financial Instruments Recognition and Measurement*; Section 3865, *Hedges* and Section 1530, *Comprehensive Income*, all of which become effective for us on January 1, 2007.

The standards require that all financial assets, including derivatives, be carried at fair value on the balance sheet, with the exception of loans, receivables and investments classified as held to maturity, which will be measured at amortized cost. Similarly, all derivative financial liabilities will be measured at fair value on the balance sheet. Other financial liabilities will be measured at amortized cost.

The standards also revise the existing accounting requirements for hedges and establish guidance for reporting comprehensive income, which includes net income and other comprehensive income. Any hedge ineffectiveness will be recognized immediately in the results of operations. Any changes in the fair value of cash flow hedging instruments, to the extent effective, will be recorded in other comprehensive income until the asset or liability being hedged affects the Statement of Operations, at which time the related change in fair value of the derivative will also be recorded in the Statement of Operations. Unrealized gains and losses on changes in the fair value of cash flow hedging instruments will be recorded as other comprehensive income until recognized in the Statement of Operations. This would include any remaining balance of deferred gain or loss on a cash flow hedge that was discontinued prior to the transition date.

Given the nature of our financial instruments and borrowing programs, we do not believe that the transitional impact of the new accounting standards will have a material financial impact on our company.

Accounting for Pension and Other Post-Retirement Costs

In October 2006, the AcSB commenced a project that is expected to result in a requirement to include the funded status (the difference between the plan assets and obligations) of an entity's post-retirement benefit plans on the balance sheet and to recognize changes in the funded status in comprehensive income in the year in which the changes occur. Current Canadian GAAP only requires disclosure of the funded status in the notes to the financial statements. The project will affect disclosures relating to our pension plan, supplementary pension plan, other post-employment and other post-retirement benefits. In addition, the proposals are expected to have a significant adverse impact on our financial ratios. The proposals, however, are not expected to impact our credit rating. The AcSB expects to publish the exposure draft for public comment in the first quarter of 2007 and it is expected to be effective for our company on December 31, 2007. This timing is expected to allow sufficient time to assess the effects on financial metrics referred to in existing contractual arrangements, including debt covenants.

Disclosure Controls and Internal Controls Over Financial Reporting

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. During 2005, we designed and evaluated the effectiveness of our disclosure control procedures. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that these disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

During 2006 we completed our documentation, evaluation and remediation of internal controls over financial reporting. Our documentation includes flowcharts of key processes, risk matrices, and overviews of test results and remediation activities. The majority of findings related to the evidencing of controls and all remediation was completed during the period. Our focus for 2007 will be the ongoing sustainment of our control environment including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2006, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the presentation of financial statements for external purposes in accordance with GAAP. Our Certifying Officers have evaluated the effectiveness of our disclosure controls and procedures and have found them to be effective.

Outlook

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our top strategic priorities relating to safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our long-term customer satisfaction and safety targets, while we maintain our strong financial profile and reliability performance. In addition, the North American Electric Reliability Council gave our transmission operating facilities, work processes and staff a grading of excellence for our ability to reliably operate and maintain Ontario's electricity transmission system. The EEI has also honoured us with an emergency recovery award, recognizing the outstanding efforts of our staff in restoring electricity service this summer after the significant damage caused by successive storms.

With the approval and implementation of the 2006 distribution rate increase, we are reasonably well positioned to address current distribution work program requirements and to earn the regulated rate of return. This will allow us to further the forestry program and continue initiatives to improve reliability and customer service. We continue to face challenges with regard to funding for our smart meter program. We expect to address some of the shortfall in our February 2007 application and anticipate full funding to be achieved over time.

We remain committed to a prudent and measured approach to distribution rationalization. The Province plans to lift the moratorium on the purchase and sale of electricity distribution assets by Hydro One, with the understanding that any future asset purchases or dispositions help further overall provincial policy interests in the sector. We plan to respond to opportunities, on a voluntary and commercial basis, where they are consistent with strategy. The investment plan does not include any funding for LDC acquisitions or divestitures. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of mission critical assets to ensure the system's continued reliability. Our transmission investment plan supports the achievement of supply mix goals, facilitates the development and use of renewable energy resources, promotes system efficiency and congestion reduction, and facilitates the integration of new supply. The OPA has presented the needs and options for reinforcing and expanding Ontario's transmission system, and discussed the specific transmission initiatives forming the basis of the preliminary IPSP. Significant investments in transmission will be required over the 20-year planning horizon of the IPSP, which is expected to be submitted by the OPA to the OEB in March 2007. In September, we filed a transmission cost of service rate application with the OEB that includes the funding required for this necessary transmission infrastructure, which is vital to the Ontario economy. Given the issued schedule, a decision on our rate application is anticipated late in 2007. Our outlook is premised on the successful outcome of this application.

Our investment plan does not include spending for large-scale investments, such as the expansion of the east-west transmission grid. Funding for required infrastructure to accommodate Bruce Peninsula supply continues beyond the planning period to 2011. Completion of the Toronto third supply option, which is expected to cost in the order of \$400 million, also extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and, as such, to maintain reliability.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

Forward-Looking Statements and Information

Our oral and written public communications, including this Management's Discussion and Analysis (MD&A), often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals for planned future capital expenditures;
- regulatory decisions regarding our revenue requirements and tariff rates;
- significant changes to Environment Canada's draft PCB regulations issued on November 4, 2006; and
- future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in this Management's Discussion and Analysis. You should review the section entitled "Risk Management and Risk Factors" in detail.

This Management's Discussion and Analysis is dated as at February 14, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2007.

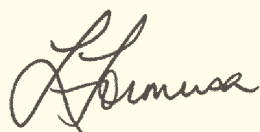
In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 45, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:



Laura Formosa
President and Chief Executive Officer (Acting)



Beth Summers
Chief Financial Officer

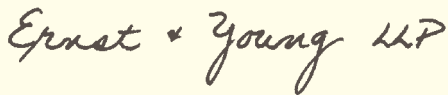
Auditors' Report

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2006 and December 31, 2005, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2006. 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 audits.

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

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and December 31, 2005, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.



Ernst & Young LLP
Chartered Accountants

Toronto, Canada
February 14, 2007

Consolidated Statements of Operations

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Revenues		
Transmission (<i>Notes 8 and 14</i>)	1,245	1,310
Distribution (<i>Notes 3 and 14</i>)	3,273	3,085
Other	27	21
	4,545	4,416
Costs		
Purchased power (<i>Notes 3 and 14</i>)	2,221	2,131
Operation, maintenance and administration	880	792
Depreciation and amortization (<i>Note 4</i>)	515	487
	3,616	3,410
Income before financing charges and provision for payments in lieu of corporate income taxes	929	1,006
Financing charges (<i>Note 5</i>)	295	325
Income before provision for payments in lieu of corporate income taxes	634	681
Provision for payments in lieu of corporate income taxes (<i>Notes 6 and 14</i>)	179	198
Net income	455	483
Basic and fully diluted earnings per common share (Canadian dollars) (<i>Note 13</i>)	4,366	4,652

Consolidated Statements of Retained Earnings

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Retained earnings, January 1	1,079	887
Net income	455	483
Dividends (<i>Note 13</i>)	(350)	(291)
Retained earnings, December 31	1,184	1,079

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

December 31

(Canadian dollars in millions)

	2006	2005
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts – \$19 million; 2005 – \$14 million) (<i>Note 14</i>)	777	628
Materials and supplies	56	56
Other	13	12
	846	696
Fixed assets (<i>Note 7</i>):		
Fixed assets in service	16,238	15,553
Less: accumulated depreciation	6,180	5,818
	10,058	9,735
Construction in progress	468	375
	10,526	10,110
Other long-term assets:		
Deferred pension asset (<i>Note 11</i>)	382	449
Regulatory assets (<i>Note 8</i>)	311	400
Goodwill	133	133
Deferred debt costs	24	23
Other assets	12	10
	862	1,015
Total assets	12,234	11,821

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31

(Canadian dollars in millions)

	2006	2005
Liabilities		
Current liabilities:		
Bank indebtedness	29	9
Accounts payable and accrued charges (Note 14)	661	700
Accrued interest	49	43
Short-term notes payable (Note 9)	60	—
Long-term debt payable within one year (Note 9)	395	589
	1,194	1,341
Long-term debt (Note 9)	4,872	4,466
Other long-term liabilities:		
Regulatory liabilities (Note 8)	473	495
Employee future benefits other than pension (Note 11)	803	716
Environmental liabilities (Note 12)	55	64
Long-term accounts payable and accrued charges	16	23
	1,347	1,298
Total liabilities	7,413	7,105
Contingencies and commitments (Notes 10, 16 and 17)		
Shareholder's equity (Note 13)		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,184	1,079
Total shareholder's equity	4,821	4,716
Total liabilities and shareholder's equity	12,234	11,821

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:



Rita Burak
Chair



Eileen Mercier
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Operating activities		
Net income	455	483
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	474	446
Transmission earnings sharing	33	—
Amortization of discount	27	58
Retail settlement variance accounts	7	12
Low-voltage services	(8)	(24)
	988	975
Changes in non-cash balances related to operations (<i>Note 15</i>)	(92)	194
Net cash from operating activities	896	1,169
Financing activities		
Long-term debt issued	775	500
Long-term debt retired	(589)	(648)
Short-term notes payable	60	(40)
Dividends paid	(350)	(291)
Termination of interest rate swap	—	(10)
Other	(4)	2
Net cash used in financing activities	(108)	(487)
Investing activities		
Capital expenditures	(823)	(691)
Other assets	15	9
Net cash used in investing activities	(808)	(682)
Net change in cash and cash equivalents	(20)	—
Cash and cash equivalents, January 1	(9)	(9)
Cash and cash equivalents, December 31 (<i>Note 15</i>)	(29)	(9)

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1.

Description of the Business

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

Note 2.

Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario) in 2007. The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate Setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review Hydro One's transmission rates and to approve revenue requirements for 2006, 2007 and 2008. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates are set. In September 2006, Hydro One Networks filed a transmission rate application. A decision on this application and the resulting revised transmission rates are anticipated in 2007.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. On the basis of the written and oral evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2006 amounted to \$386 million (2005 – \$377 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act*, 1998, Hydro One is required to make payments in lieu of corporate taxes to the 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 *Corporations Tax Act* (Ontario) as modified by the *Electricity Act*, 1998, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis.

Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2006 – 6.39%; 2005 – 6.80%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated Service Lives (years)	
	Range	Average
Transmission	12–100	55
Distribution	15–75	41
Communication	7–40	19
Administration and service	5–50	39

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt.

Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations. Hedging gains and losses are amortized over the period of the related debt.

The Company does not engage in derivative trading or speculative activities.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Note 3.

Electricity Credits to Customers

Under a regulation issued in October 2005, Regulated Price Plan customers received a credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by \$140 million. The application of the credit did not result in any adjustment to net income.

Note 4.

Depreciation and Amortization

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Depreciation of fixed assets in service	379	369
Fixed asset removal costs	41	41
Amortization of regulatory and other assets	95	77
	515	487

Note 5.

Financing Charges

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Interest on short-term notes payable	2	1
Interest on long-term debt payable	296	297
Amortization of discount	27	58
Other	9	5
Less: Interest capitalized on construction in progress	(28)	(21)
Interest capitalized on regulatory assets	(7)	(10)
Interest earned on investments	(4)	(5)
	295	325

Note 6.**Provision for Payments in Lieu of Corporate Income Taxes**

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Income before provision for PILs	634	681
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	229	246
(Decrease) increase resulting from:		
Net temporary differences:		
Recovery of PILs related to prior years	(30)	(21)
Pension contribution in excess of pension expense	(16)	(25)
Employee future benefits other than pension expense in excess of cash payments	14	8
Transmission amounts received but not recognized for accounting purposes due to earnings sharing mechanism	12	–
Overhead capitalized for accounting but deducted for tax purposes	(11)	(10)
Interest capitalized for accounting purposes but deducted for tax purposes	(13)	(11)
Environmental expenditures	(6)	(5)
Capital cost allowance (in excess of) less than depreciation and amortization	(3)	1
Other	4	1
Net temporary differences	(49)	(62)
Permanent differences:		
Large corporations tax	–	13
Other	(1)	1
Net permanent differences	(1)	14
Provision for PILs	179	198
Effective income tax rate	28.23%	29.07%

In 2006, Hydro One recognized a tax benefit of approximately \$30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized. In 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to utilize the subsidiary's accumulated tax losses and a future tax asset of approximately \$21 million was recognized. As at December 31, 2006, approximately \$2 million of the 2005 amount remains available for use in 2007.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2006, future income tax liabilities of \$281 million (2005 – \$265 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been higher by approximately \$16 million, including the impact of a change in substantively enacted tax rates.

Note 7.

Fixed Assets

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	–	422
	16,238	6,180	468	10,526
2005				
Transmission	8,124	2,889	233	5,468
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	–	421
	15,553	5,818	375	10,110

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were \$28 million in 2006 (2005 – \$21 million).

Note 8.**Regulatory Assets and Liabilities**

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities (see Note 2):

December 31

(Canadian dollars in millions)

	2006	2005
Regulatory assets:		
Regulatory asset recovery account I	58	88
Regulatory asset recovery account II	87	92
Employee future benefits other than pension	84	126
Environmental	70	79
Smart meters	10	–
Retail settlement variance accounts	–	11
Other	2	4
Total regulatory assets	311	400
Regulatory liabilities:		
Deferred pension	382	449
Export and wheeling fees	49	32
Transmission earnings sharing	34	–
Retail settlement variance accounts	2	–
Other	6	14
Total regulatory liabilities	473	495

Regulatory Assets**Regulatory Asset Recovery Account I (RARA I)**

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately \$20 million (2005 – \$20 million). In addition, related financing charges would have been higher by \$3 million (2005 – \$7 million).

Regulatory Asset Recovery Account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately \$16 million. In addition, related financing charges would have been higher by \$5 million.

Employee Future Benefits Other than Pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of \$419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of two years (2005 – three years) and does not earn a return. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower by approximately \$42 million (2005 – \$42 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate-regulated accounting, amortization expense in 2006 would have been lower and operation, maintenance and administration expense would have been higher by \$17 million (2005 – \$14 million).

Smart Meters

On March 21, 2006, the OEB approved the establishment of deferral accounts for smart meter related expenditures and a monthly customer charge of 30 cents per residential customer was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company has recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In the absence of rate-regulated accounting, the Company's operation, maintenance and administration expense would have been higher by \$4 million and revenues would have been higher by \$2 million.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid to the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately \$12 million (2005 – \$38 million), assuming no regulatory deferral of distribution and Inergi LP (Inergi) pension-related amounts. In addition, related financing charges would have been higher by \$2 million (2005 – \$4 million).

Export and Wheeling Fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of \$1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of this export and wheeling fee, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006.

Transmission Earnings Sharing

On February 21, 2006, the OEB issued a decision that established an earnings sharing mechanism in which 50% of any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates are set, will be equally split between the Company's shareholder and ratepayers. The excess earnings calculation will be based on the 2006 audited financial statements of Hydro One Networks' transmission business. The application of the earning sharing mechanism will be subject to future OEB review and approval. Any changes resulting from this review will be reflected in results of operations when the OEB renders its decision.

Retail Settlement Variance Accounts

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its retail settlement variance accounts since May 1, 2006 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

Note 9.**Debt**

December 31

(Canadian dollars in millions)

	2006	2005
Short-term notes payable	60	–
Long-term debt:		
4.15% notes due 2006	–	280
4.20% notes due 2006	–	168
4.30% notes due 2006	–	141
4.45% notes due 2007	282	282
4.55% notes due 2007	73	73
4.10% notes due 2007 ¹	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	–
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	350
6.59% notes due 2043	315	315
5.00% notes due 2046	75	–
	5,270	5,084
Less: Long-term debt payable within one year	(395)	(589)
Net unamortized premiums (discounts)	9	(14)
Unamortized hedging losses	(12)	(15)
Long-term debt	4,872	4,466

¹ Step-up coupon, after year three from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2006, the notes had a weighted-average interest rate of 4.2%.

Hydro One has a \$750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2007, with a two-year extension option. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's commercial paper program.

The Company issues notes for long-term financing under the medium-term note program. The maximum authorized principal amount of medium-term notes issuable under this program is \$2,500 million of which \$1,725 million is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2006, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures (Canadian dollars in millions)	Weighted Average Interest Rate (%)
1 year	395	4.4
2 years	500	4.0
3 years	400	4.0
4 years	400	7.2
5 years	250	6.4
	1,945	5.0
6–10 years	1,050	5.3
Over 10 years	2,275	6.4
	5,270	5.7

Note 10.**Fair Value of Financial Instruments and Risk Management**

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31

(Canadian dollars in millions)

	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt ¹	5,270	5,831	5,084	5,697

¹ The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into derivative agreements, such as forward fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2006, Hydro One did not enter into any such derivative agreements. In 2005, Hydro One terminated forward interest rate swap agreements entered into in 2005 and 2004 and having a total notional principal amount of \$150 million, resulting in a loss of \$10 million. The loss is being amortized on an annuity basis over the 30-year term of the related debt.

As at December 31, 2006, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of \$40 million and a fair value of \$nil (2005 – \$nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2006 or in 2005.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2006, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2006, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

Note 11.**Employee Future Benefits**

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately \$1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2006 and 2005 was as follows:

December 31	% of Plan Assets	
	2006	2005
Equity securities	64.6	60.6
Debt securities	32.0	36.2
Other	3.4	3.2
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of \$92 million and \$79 million at December 31, 2006 and 2005, respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed on September 22, 2004, effective for December 31, 2003, the Company contributed \$86 million to its pension plan in respect of 2006 (2005 – \$83 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on actuarial valuation effective December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2006, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was \$122 million in 2006 (2005 – \$123 million).

Year ended December 31 (Canadian dollars in millions)	Pension		Employee Future Benefits Other than Pension	
	2006	2005	2006	2005
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	5,355	4,862	1,143	966
Current service cost	106	83	33	26
Interest cost	267	277	58	57
Benefits paid	(253)	(248)	(36)	(40)
Plan amendments	6	–	22	1
Net actuarial (gain) loss	(70)	381	(120)	133
Accrued benefit obligation, December 31	5,411	5,355	1,100	1,143
Change in plan assets				
Fair value of plan assets, January 1	4,713	4,243	–	–
Actual return on plan assets	571	630	–	–
Benefits paid	(253)	(248)	–	–
Employer's contributions ¹	86	83	–	–
Employees' contributions	17	16	–	–
Administrative expenses	(11)	(11)	–	–
Fair value of plan assets, December 31	5,123	4,713	–	–
Funded status				
(Unfunded benefit obligation)	(288)	(642)	(1,100)	(1,143)
Unamortized net actuarial losses	645	1,069	236	385
Unamortized past service costs	25	22	25	6
Deferred pension asset (accrued benefit liability)	382	449	(839)	(752)
Less: current portion	–	–	36	36
Deferred pension asset (long-term liability)	382	449	(803)	(716)

¹ In January 2007, the Company made a contribution of \$8 million in respect of 2006 (2006 – \$8 million in respect of 2005).

Year ended December 31 (Canadian dollars in millions)	Employee Future Benefits			
	Pension		Other than Pension	
	2006	2005	2006	2005
Components of net periodic benefit cost				
Current service cost, net of employee contributions	89	67	33	26
Interest cost	267	277	58	57
Actual return on plan asset net of expenses	(560)	(619)	–	–
Actuarial (gain) loss	(70)	381	(120)	133
Plan amendments	6	–	22	–
Other	(1)	–	(1)	–
Costs arising in the period	(269)	106	(8)	216
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	248	327	–	–
Actuarial loss (gain)	177	(268)	149	(113)
Plan amendments	(3)	3	(19)	–
Net periodic benefit cost ²	153	168	122	103
Charged to results of operations ²	42	23	75	64
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	–	–	156	171
Service cost and interest cost	–	–	13	12
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	–	–	(124)	(133)
Service cost and interest cost	–	–	(10)	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.75%	7.00%	–	–
Weighted-average discount rate	5.00%	5.75%	4.98%	5.93%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.75%	2.50%	2.75%
Average remaining service life of employees (years)	10	10	10	10
Rate of increase in health care cost trend ³	–	–	4.40%	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	5.25%	5.00%	5.24%	4.98%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%
Rate of increase in health care cost trend ⁴	–	–	4.40%	4.40%

² The Company follows the cash basis of accounting. During 2006, pension costs of \$86 million (2005 – \$83 million) were attributed to labour, of which \$42 million (2005 – \$23 million) was charged to operations, \$34 million (2005 – \$32 million) was capitalized as part of the cost of fixed assets, and \$10 million (2005 – \$28 million) was attributed to a regulatory asset.

³ 7.87% in 2006 grading down to 4.40% per annum in and after 2014 (2005 – 8.47% in 2005 grading down to 4.40% per annum in and after 2014).

⁴ 8.69% in 2007 grading down to 4.40% per annum in and after 2014 (2005 – 7.87% in 2005 grading down to 4.40% per annum in and after 2014).

Note 12.**Environmental Liabilities**

December 31

(Canadian dollars in millions)

	2006	2005
Environmental liabilities, January 1	79	89
Interest accretion	5	5
Expenditures	(17)	(14)
Revaluation adjustment	3	(1)
Environmental liabilities, December 31	70	79
Less: current portion	(15)	(15)
	55	64

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – \$15 million; 2008 – \$14 million; 2009 – \$12 million; 2010 – \$10 million; 2011 – \$7 million; and thereafter – \$31 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

Note 13.**Share Capital****Common and Preferred Shares**

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of \$25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of \$18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of \$25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2006, preferred dividends in the amount of \$18 million (2005 – \$18 million) and common dividends in the amount of \$332 million (2005 – \$273 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

Note 14.

Related Party Transactions

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2006 includes \$1,206 million (2005 – \$1,276 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2006 includes \$127 million (2005 – \$127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2006 includes \$21 million (2005 – \$21 million) related to these services.

In 2006, Hydro One purchased power in the amount of \$2,183 million (2005 – \$2,095 million) from the IESO administered electricity market and \$38 million (2005 – \$36 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2006, Hydro One incurred \$9 million (2005 – \$7 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were \$15 million (2005 – \$11 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than \$1 million in each of 2006 and 2005.

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31

(Canadian dollars in millions)

	2006	2005
Accounts receivable	114	116
Accounts payable and accrued charges	(230)	(263)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of \$195 million (2005 – \$213 million).

Note 15.**Consolidated Statements of Cash Flows**

For the purposes of the consolidated statements of cash flows, “cash and cash equivalents” refers to the balance sheet item “bank indebtedness.”

The changes in non-cash balances related to operations consist of the following:

Year ended December 31

(Canadian dollars in millions)

	2006	2005
Accounts receivable (increase) decrease	(149)	87
Materials and supplies increase	–	(9)
Accounts payable and accrued charges (decrease) increase	(39)	68
Accrued interest increase (decrease)	6	(1)
Long-term accounts payable and accrued charges decrease	(7)	(3)
Employee future benefits other than pension increase	87	62
Other	10	(10)
	(92)	194
Supplementary information:		
Interest paid	302	300
Payments in lieu of corporate income taxes	252	210

Note 16.**Contingencies****Legal Proceedings**

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company’s consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band’s traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001

as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPC would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by the OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than \$850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

Note 17.

Commitments

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. The initial service level price ranged between \$90 million and \$130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2006, and in total thereafter are as follows: 2007 – \$110 million; 2008 – \$98 million, 2009 – \$94 million; 2010 – \$91 million; 2011 – \$87 million; and thereafter – \$16 million.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2006, the Company provided prudential support, using a combination of bank letters of credit of \$22 million (2005 – \$21 million) and parental guarantees of \$275 million (2005 – \$275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2006, Hydro One had bank letters of credit of \$93 million (2005 – \$82 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2006 and in total thereafter are as follows: 2007 – \$5 million; 2008 – \$5 million; 2009 – \$4 million; 2010 – \$1 million; 2011 – \$nil; and thereafter – \$1 million.

Note 18.

Segment Reporting

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The “other” segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31

(Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	–	2,221	–	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823
2005				
Segment profit				
Revenues	1,310	3,085	21	4,416
Purchased power	–	2,131	–	2,131
Operation, maintenance and administration	353	413	26	792
Depreciation and amortization	246	236	5	487
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	711	305	(10)	1,006
Financing charges				325
Income before provision for payments in lieu of corporate income taxes				681
Capital expenditures	349	338	4	691

December 31

(Canadian dollars in millions)	2006	2005
Total assets		
Transmission	6,965	6,827
Distribution	5,170	4,902
Other	99	92
	12,234	11,821

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

Note 19.

Comparative Figures

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2006 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31

(Canadian dollars in millions)

	2006	2005	2004	2003	2002
Statement of operations data					
Revenues					
Transmission	1,245	1,310	1,262	1,298	1,317
Distribution	3,273	3,085	2,874	2,734	2,682
Other	27	21	17	26	32
	4,545	4,416	4,153	4,058	4,031
Costs					
Purchased power	2,221	2,131	1,987	1,872	1,858
Operation, maintenance and administration ¹	880	792	771	795	832
Depreciation and amortization	515	487	480	454	411
	3,616	3,410	3,238	3,121	3,101
Regulatory recovery ²	–	–	91	–	–
Income before financing charges and provision for payments in lieu of corporate income taxes	929	1,006	1,006	937	930
Financing charges	295	325	331	348	353
Income before provision for payments in lieu of corporate income taxes	634	681	675	589	577
Provision for payments in lieu of corporate income taxes	179	198	177	193	233
Net income	455	483	498	396	344
Basic and fully diluted earnings per common share (Canadian dollars)	4,366	4,652	4,798	3,779	3,258

December 31

(Canadian dollars in millions)

Balance sheet data					
Assets					
Transmission	6,965	6,827	6,785	6,589	6,638
Distribution	5,170	4,902	4,845	4,623	4,694
Other	99	92	95	94	90
Total assets	12,234	11,821	11,725	11,306	11,422
Liabilities					
Current liabilities					
(including current portion of long-term debt)	1,194	1,341	1,262	1,192	1,894
Long-term debt	4,872	4,466	4,613	4,539	3,938
Other long-term liabilities	1,347	1,298	1,326	1,284	1,451
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	1,184	1,079	887	654	502
Total liabilities and shareholder's equity	12,234	11,821	11,725	11,306	11,422

Year ended December 31

(Canadian dollars in millions)

	2006	2005	2004	2003	2002
Other financial data					
Capital expenditures					
Transmission	402	349	432	289	260
Distribution	417	338	288	292	286
Other	4	4	7	16	24
Total capital expenditures	823	691	727	597	570
Ratios					
Net asset coverage on long-term debt ³	1.92	1.93	1.88	1.86	1.90
Earnings coverage ratio ⁴	2.67	2.69	2.70	2.43	2.35
Operating statistics					
Transmission					
Units transmitted (TWh) ⁵	151.1	157.0	153.4	151.7	153.2
Ontario 20-minute system peak demand (MW) ⁵	27,056	26,219	25,204	24,849	25,629
Ontario 60-minute system peak demand (MW) ⁵	27,005	26,160	24,979	24,753	25,414
Total transmission lines (circuit-kilometres)	28,600	28,547	28,643	28,621	28,492
Distribution					
Units distributed to Hydro One customers (TWh) ⁵	29.0	29.7	28.5	27.9	27.1
Units distributed through Hydro One lines (TWh) ^{5,6}	44.7	45.6	44.8	44.7	45.1
Total distribution lines (circuit-kilometres)	122,460	122,118	121,736	121,285	120,767
Customers	1,293,396	1,273,768	1,258,925	1,238,748	1,219,614
Total regular employees	4,295	4,189	4,118	3,967	3,933

¹ Operation, maintenance and administration costs for 2002 included a charge of \$25 million for a staff reduction program.

² As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of \$91 million was recorded.

³ The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

⁴ The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

⁵ System-related statistics include preliminary figures for December.

⁶ Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Board of Directors (as at December 31, 2006)



Rita Burak²
Chair of the Board
of Directors,
Hydro One Inc.



Sami Bébawi^{5,6}
Executive Vice President,
Office of the President,
President, Socotec Inc.,
SNC-Lavalin Group Inc.



Murray J. Elston^{1,3,5}
President and CEO,
Canadian Nuclear
Association



Don MacKinnon^{5,6}
President, Power
Workers' Union



Eileen A. Mercier^{1,2,4*}
Corporate Director
Resigned March 16, 2007



Walter Murray^{1,3,4}
Corporate Director



Kathleen O'Neill^{1,2,3,4*}
Corporate Director
Resigned January 24, 2007



Douglas E. Speers^{1,4,6}
Chairman and Director,
Emco Corporation



Kenneth D. Taylor^{5,6*}
Chair, Taylor and
Ryan Inc.
Resigned February 27, 2007



Blake Wallace, Q.C.^{2,3,5*}
Vice President and
Director, Murray
& Company
Resigned February 26, 2007

Board Committees

¹ Audit and Finance Committee

The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met five times in 2006.

² Corporate Governance Committee

The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandates of each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2006.

³ Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have significant impact on us. The committee met eight times in 2006.

⁴ Information Technology Committee

The Information Technology Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met three times in 2006.

⁵ Regulatory and Environment Committee

The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met five times in 2006.

⁶ Health and Safety Committee

The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2006.

* Effective March 30, 2007, the following directors were elected to the Board of Directors of Hydro One Inc. by our shareholder: Kathryn Bouey; Laura Formosa; Michael Mueller; Robert Pace; and Gale Rubenstein in place of Eileen Mercier, Kathleen O'Neill, Tom Parkinson, Honourable Bob Rae, Kenneth Taylor and Blake Wallace, who have resigned as members of the Board. As well, the number of directors of the Corporation was reduced from 12 to 11.

Corporate Information

Corporate Address

483 Bay Street
Toronto, Ontario
M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations

(416) 345-6867
investor.relations@HydroOne.com

Media Inquiries

(416) 345-6868
1-877-506-7584

Customer Inquiries

Power outage and
emergency number:
1-800-434-1235

Residential, farm &
small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors

Ernst & Young LLP

Philanthropy

Making life better for electrical burn patients

In 2006, Hydro One, Sunnybrook Health Sciences Centre and St. John's Rehab Hospital announced the Hydro One Chair in Electrical Injury, a permanently endowed fund to support clinical and academic leadership in the field of electrical injury. Over the next five years, Hydro One has committed \$500,000 to push forward research and treatment of electrical burn patients.

“Electrical burns are not very well understood and often the damage they do goes unseen and undiagnosed,” said Dr. Joel Fish, Medical Director at the Ross Tilley Burn Centre at Sunnybrook Health Sciences Centre. “The research enabled by this funding will do a great deal to improve treatment and rehabilitation for burn patients.”

Since 2003, Hydro One and Sunnybrook Health Sciences Centre have worked together to make the expertise of the Ross Tilley Burn Centre available through the hospital's teleconference capability and the NORTH Network telemedicine network to electrical burn patients across Ontario and Canada. Every year, between 600 and 800 workplace electrical burns occur in Canada, the vast majority of them to workers outside of the electricity sector.

The proper care and treatment for electrical burn patients is important not only to those of us in the electrical industry, but also to workers in every sector.



Dr. Joel Fish
Medical Director, Ross Tilley Burn Centre



Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value.

Hydro One Inc.

483 Bay Street
Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com



RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2005

FEBRUARY 16, 2006

HYDRO ONE INC.
ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2005

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Except where otherwise indicated, all information presented herein is as at December 31, 2005.

DEFINITIONS

For convenience, in this Annual Information Form:

“**Hydro One**”, “**our company**”, “**we**”, “**us**”, and “**our**” refer to Hydro One Inc. and its subsidiaries and predecessors, except where the context requires otherwise;

“**IESO**” refers to the Independent Electricity System Operator, previously named the Independent Electricity Market Operator;

“**OEB**” refers to the Ontario Energy Board;

“**Ontario**” refers to the Province of Ontario as a geographical area;

“**Open Access**” refers to the opening of Ontario’s wholesale and retail electricity markets to competition which officially occurred on May 1, 2002; and

“**Province**” refers to the Government of the Province of Ontario.

CORPORATE STRUCTURE

Hydro One Inc. was incorporated as Ontario Hydro Services Company Inc. by Articles of Incorporation dated December 1, 1998 under the *Business Corporations Act* (Ontario). On May 1, 2000, we changed our name to Hydro One Inc.

Our registered office and head office is located at 483 Bay Street, 15th Floor, North Tower, Toronto, Ontario, M5G 2P5.

The following are our principal subsidiaries, each of which is wholly owned by us and is incorporated under the laws of Ontario:

- Hydro One Networks Inc. — carries on all business relating to our ownership, operation and management of electricity transmission and distribution systems and facilities;
- Hydro One Brampton Inc. — carries on the business relating to our ownership, operation and management of electricity distribution systems and facilities in Brampton, Ontario, through its wholly owned subsidiary, Hydro One Brampton Networks Inc.;
- Hydro One Remote Communities Inc. — carries on all business relating to our ownership, operation, maintenance and construction of generation and distribution assets used in the supply of electricity to remote communities throughout northern Ontario; and

- Hydro One Telecom Inc. — carries on all of our business relating to leasing dark fibre and providing lit telecommunications capacity to other telecommunication carriers, large corporations, government, healthcare, and education institutions.

FORWARD-LOOKING INFORMATION

This Annual Information Form contains and Hydro One's oral and written public communications often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business of Hydro One and the industry in which Hydro One operates and includes beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements about the general development of our business; recent regulatory developments including the installation of smart meters; our strategy as it relates to safety, reliability, productivity and cost efficiency; expectations regarding key capital expenditures; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licences, rate orders and rate structures in both our transmission and distribution businesses; the nature of our relationship with the Province; environmental matters; and legal proceedings in which we are currently involved. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and Hydro One disclaims any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise.

These forward looking statements are based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable competitive environment; and no significant event occurring outside the ordinary course of business such as a natural disaster or other calamity. These assumptions are based on information currently available to Hydro One including information obtained by Hydro One from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, its business, results of operations, financial condition and its credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;

- the potential for service disruptions and increased costs if we fail to maintain and improve our aging asset base;
- the risks to our facilities posed by severe weather, other natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the potential failure to achieve anticipated reductions in operating costs from our outsourcing arrangement with Inergi LP;
- the inability to further improve our labour productivity;
- the risks related to the high number of retirements anticipated over the next few years and our potential inability to hire and recruit replacement staff;
- the potential for substantial and currently undetermined environmental costs and liabilities;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures, dividends and other obligations;
- the risk that we may be required to make substantial contributions to our pension plan;
- the risk that we may be subject to significant costs to complete the transfer of transmission, distribution and other assets located on Indian lands; and
- the impact of the acquisition by the Province of owned lands underlying our transmission system.

Hydro One cautions you that the above list of factors is not exclusive. Some of these and other factors are discussed in more detail under “Risk Factors” in this Annual Information Form. You should review the section entitled “Risk Factors” in detail.

GENERAL DEVELOPMENT OF THE BUSINESS

Our industry has undergone significant restructuring initiated by the Province over the past several years. On Open Access in May, 2002, Ontario’s electricity generators were required to compete with suppliers, from both within and outside Ontario, to sell electricity to the large purchasers of bulk power that comprise the wholesale market, consisting of distributors and large customers. These purchasers are responsible, either directly or through an intermediary, for making their own arrangements for buying electricity through bidding in the real-time (spot) market administered by the IESO. In addition, market participants are permitted to enter into bilateral contracts under which the parties may either buy or sell a specified quantity of electricity for delivery at an agreed price at an agreed time or agree to make a payment to one party or the other based on agreed to financial arrangements. Customers are free to select the electricity supplier of their choice, but distributors, including our company, must continue to serve those customers that have not elected to buy their electricity from competing retail suppliers through the provision of standard supply service. Distribution companies pass through

the cost of providing this standard supply service in the manner approved by the OEB to those distribution customers who do not choose to sign contracts with competitive retailers. Such competing retailers must be licensed by the OEB and may include affiliates of existing local distribution companies or of our company, electricity generators and gas marketers.

We are wholly owned by the Province and our transmission and distribution businesses are regulated by the OEB. Our industry, including our company, is governed within the broad legislative framework of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended.

The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* were significantly amended by the Province during 2002. The *Reliable Energy and Consumer Protection Act, 2002*, which received Royal Assent and came into force on June 27, 2002, among other matters, clarified the Province's rights to acquire, hold, transfer, dispose of or otherwise deal with securities, debt obligations of, or any other interest in, Hydro One and transferred, effective December 31, 2002, ownership of the transmission corridor lands from Hydro One to the Province in exchange for a statutory right to use the land for transmission and distribution purposes.

Effective May 1, 2002, the commodity price for electricity for low volume and designated customers was fixed at 4.3 cents per kWh. Also in 2002, transmission and distribution rates were capped at the levels in effect on November 11, 2002. Commencing on April 1, 2004, the commodity price for the first 750 kWh of electricity consumption per month by low volume and designated customers was changed to 4.7 cents per kWh and consumption in excess of that amount was fixed at a rate of 5.5 cents per kWh. On April 1, 2005, the OEB implemented the new regulated price plan structure for low volume and designated customers ("RPP"). The RPP maintained the current two-tiered pricing structure, but set new prices for electricity of 5.0 cents per kWh for the first 750kWh and 5.8 cents per kWh thereafter. The RPP also introduced different seasonal consumption thresholds for residential customers. This process began in November, 2005 with the threshold for the second tier price rising from 750 kWh to 1,000 kWh per month through April 30, 2006 when it will lower to 600 kWh per month through October 31, 2006. Power sales revenue in excess of a distributor's cost of power, as well as shortfalls are financed by the Ontario Power Authority through a variance account.

Commencing on March 1, 2004, distributors were permitted to start recovering certain distribution regulatory assets in their rates. Accordingly, in January 2004, we had filed an application with the OEB for approval of distribution rate adjustments reflecting recovery of these regulatory assets for the period from market opening to December 31, 2003. Final approval was given by the OEB on December 9, 2004. Based on this final order, we implemented rate adjustments on April 1, 2005 to recover the approved amounts.

The *Electricity Restructuring Act, 2004* received Royal Assent on December 9, 2004. It promotes the expansion of electricity supply and capacity, facilitates load and demand management, encourages conservation and efficiency and regulates prices in parts of the electricity sector. The portion of the Act which creates the Ontario Power Authority to oversee the integrated planning for electricity generation, transmission, conservation and load management, and to undertake procurement of electricity was proclaimed into force on December 20, 2004.

On December 21, 2004, the Ontario Ministry of Energy released a paper entitled “Electricity Transmission and Distribution in Ontario – a Look Ahead”. This paper focuses on the following three topics:

- (a) Opportunities to achieve efficiencies in the distribution sector through consolidation and functional rationalization;
- (b) Measures to facilitate and promote distributed generation; and
- (c) Ensuring adequate transmission capacity via appropriate incentives and streamlined approvals processes.

DESCRIPTION OF THE BUSINESS

Overview

We are the leading electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario’s electricity transmission system, accounting for approximately 97% of Ontario’s transmission capacity as measured by revenues for the year ended December 31, 2005. Our transmission system is one of the largest in North America based on assets as at December 31, 2005. Our distribution system is the largest in Ontario based on assets as at December 31, 2005 and spans approximately 75% of Ontario, serving approximately 1.3 million customers. We have three reportable segments: (1) our transmission business; (2) our distribution business; and (3) our other business.

Our transmission business, which represented approximately \$6.8 billion of our total assets of \$11.8 billion as at December 31, 2005, transmits electricity through an approximately 28,500 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution network, 51 local distribution companies and 66 large industrial customers directly connected to our transmission system. We also own and operate 26 facilities that interconnect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately \$4.9 billion of our total assets of \$11.8 billion as at December 31, 2005, distributes electricity through our approximately 124,500 circuit-kilometre low-voltage distribution system to municipalities and in rural areas. Customers of our distribution business include 35 local distribution companies that are not directly connected to our transmission system, 50 large industrial customers and approximately 1.3 million rural and urban customers. Hydro One Brampton Networks Inc. is an urban distribution company, serving approximately 116,000 customers in the Greater Toronto Area with approximately 4,650 circuit-kilometres of lines with phase multiplier. We also operate through our subsidiary, Hydro One Remote Communities Inc., small, regulated generation and distribution systems in 18 remote communities across Northern Ontario that are not connected to Ontario’s electricity grid.

Our other business segment is primarily represented by the operations of Hydro One Telecom Inc. This subsidiary markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment constituted \$93 million of our total assets of \$11.8 billion as at December 31, 2005.

The OEB regulates our transmission and distribution businesses and issues rate orders to establish the revenue requirements required to cover the approved costs of these businesses plus a specified rate of return. In 2001, the OEB approved a performance based regulatory (“PBR”) framework for Ontario’s electricity distribution business but due to delays in the implementation in rate changes as a consequence of the *Electricity Pricing, Conservation and Supply Act, 2002*, the implementation of this PBR framework was suspended. PBR is a form of rate setting that provides financial incentives to reduce costs below the levels used by the OEB in establishing rates that apply for a specified period of time. Under PBR, regulated utilities have greater incentives to improve their operating efficiency as they can participate in savings beyond certain thresholds established by the regulator. We anticipate that the OEB will re-institute a form of PBR for distribution utilities as early as 2008.

While the *Electricity Pricing, Conservation and Supply Act, 2002* suspended the implementation of the PBR framework for the distribution sector, we anticipate our distribution returns to improve and approach full commercial return after 2006.

Recent Developments

Ontario Power Authority

The *Electricity Restructuring Act, 2004* received Royal Assent on December 9, 2004. The portion of the legislation establishing the Ontario Power Authority was proclaimed into force on December 20, 2004. The Ontario Power Authority’s mandate is to ensure the adequacy and efficiency of electricity supply in the Province through planning of electricity supply and demand. See “Statutory and Operating Framework” for further information.

The Ontario Power Authority issued its Supply Mix Advice Report, which provides support for future generation options for Ontario, on December 9, 2005 to the Minister of Energy. The Report’s recommendations, if accepted, will provide a foundation for the Ontario Power Authority’s Integrated Power System Plan, which will determine a long-term demand forecast and develop a portfolio of supply and conservation/demand management options to address the forecast. The Report also recognizes the critical role that transmission plays in delivering these options and recommends in its Action Plan that, given the urgency of generation needs, immediate initiatives be undertaken to streamline approvals to ensure that the necessary electricity system infrastructure can be developed with greater certainty than at present. The Ontario Power Authority is expected to submit the Integrated Power System Plan to the Ontario Energy Board for review in the summer of 2006.

Replacement of Meters

In November, 2005, the Province introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by 2010. These meters will be capable of measuring and reporting usage over predetermined periods being read remotely and providing customers with access to information about their electricity consumption. Smart meters are regarded by the Province as an integral means of promoting a culture of conservation.. Due to the high level of uncertainty surrounding the implementation details of the smart meters program, and our

anticipation that the resulting expenditures will be fully recoverable, no specific costs have been included in our capital expenditures outlook at this time.

Conservation and Demand Management

The Province has established specific targets for Conservation and Demand Management (“C&DM”) and Hydro One’s distribution utilities have built expenditures into their plans to meet these targets. Local distributors, including Hydro One’s distribution business, will be allowed to recover their third stage market adjusted rate of return, conditional on their re-investing the after-tax equivalent of one year of these revenues in conservation and demand management initiatives. For Hydro One Networks Inc. and Hydro One Brampton Networks Inc., the total conservation and demand management revenue available was approximately \$42.7 million. Hydro One submitted C&DM plans for this full amount to the OEB on January 11, 2005. Hydro One received approval of its C&DM plan on behalf of Hydro One Networks Inc. on February 18, 2005 on the condition that planned spending on smart meters for 2006 (\$7.1 million) be re-directed to other projects. On November 1, 2005 the revised plan was approved as filed, enabling total expenditures of \$39.5 million. On February 18, 2005, Hydro One Brampton Networks Inc.’s plan for \$3.2 million in C&DM spending was also approved as filed. On February 2, 2005, Hydro One Remote Communities Inc. received interim approval, as requested, for a C&DM plan for \$300,000.

Ten Year Transmission Plan

Our company updated our 10-year transmission plan in 2005. This transmission plan will evolve in conjunction with the evolution of Ontario’s electricity sector. The updated plan describes the transmission options that are being developed in response to the transmission, interconnection and generation supply constraints and other problems affecting different geographic areas across Ontario.

Our Strategy

Our goals are to be recognized by our customers as their best service provider; by our peers as their benchmark for excellence; and by our shareholder as delivering superior value. We seek to achieve these goals by continuing to implement the following strategies:

- *Safety*: Create and maintain an injury-free workplace with a concentrated focus on prevention of serious incidents and injuries through effective culture change. See “Health and Safety”.
- *Customer Service*: Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers’ level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers that acknowledge their commercial requirements.
- *Reliability*: Enhance reliability and service standards in our transmission and distribution systems while continuing to expand and improve the performance of the transmission system to meet Ontario’s future supply needs.

- *Financial:* Ensure our actions contribute to maximizing the value of our company while maintaining an effective borrowing capability through stable credit quality and delivering stable financial returns to our shareholder.
- *Employee and Labour Relations:* Focus on developing skills, succession planning and managing labour demographics.
- *Productivity and Cost Efficiency:* Continue to promote productivity and cost efficiency.

Focusing on safety

Our top strategic priority is to eliminate serious injuries and close calls that have the potential to cause serious injury. Several existing strategic initiatives that were endorsed in 2005 are expected to continue to be implemented and a number of existing programs are expected to be strengthened over the planning period in order to achieve and sustain the required cultural change. These initiatives include an increased focus on incident prevention and job planning, a comprehensive health and safety management system, a compliance review program, safety rotations involving the major lines of business and a fleet safety program.

Continuing to improve our customer service focus

We have been actively helping our customers understand the changing industry structure, changes affecting their bills, the increased priorities on conservation and demand management, and our role in ensuring adequacy and security of supply.

For our distribution connected residential and seasonal customers, we have increased the capability and capacity of our call centre to meet customer needs and to provide faster telephone response time and have also expanded the services offered through our website. We have undertaken a major upgrade of our billing system to enable it to handle smart meters and more complex rate tables. We have also undertaken extensive customer communications to address their information needs by providing our agents with faster access to customer information and reducing the risk of telephone system failure. We have also completed the installation of an Outage Response Management System to give customers better information on local outage restoration efforts.

For our mid-size business customers, we have assigned our Field Superintendents to manage the customer relationship. We have found that this local presence has improved our responsiveness to our customers' needs.

For our large transmission connected industrial customers and local distribution companies, we continue to have a dedicated account executive for each account over 5 MW of load. In addition, we have made a senior member of management available for our largest 35 customers. This gives each of these customers a senior internal contact which we believe fosters an improved relationship.

Reliability

A prime goal of our transmission and distribution capital program over the next few years will be to improve the condition of our assets and to continue to ensure their reliability with an emphasis on assets critical to bulk network integrity.

Transmission

Transmission capital expenditures include the replacement of power transformers, circuit breakers, protection and control equipment, line components and telecommunication equipment, among others, that have reached the end of their useful service life. Transmission capital expenditures also relate to the development and expansion of the transmission system in order to meet Ontario's future needs.

Transmission system capital expenditures are currently expected to remain relatively constant over the period 2005 to 2007 with a marginal increase in 2008. The Ontario Power Authority is developing an Integrated Power System Plan to address identified supply needs in the Province. It is anticipated that the Integrated Power System Plan will be filed with the OEB in the summer of 2006. Using our 10-year transmission plan as a basis, we are continuing to work closely with the Ontario Power Authority on transmission solutions to address the Province's supply needs. A number of specific initiatives are nearing completion or are well underway. One of these is the Niagara Reinforcement Project, which is designed to relieve transmission bottlenecks that limit transfer of Niagara area generation and imports from New York State. Other projects include the construction of underground transmission cables in downtown Toronto, the recently completed Parkway Transformer Station in Markham, and the installation of capacitor banks in the west end of the Greater Toronto Area and other affected areas.

At the local level, we continue to address supply issues with our customers. For projects required to provide reliable supply to communities, the participation and support of the affected local utilities as partners in joint planning studies and throughout the consultation and approval processes is key for maintaining the safe and reliable delivery of electricity. Examples of projects initiated to meet the growing needs of our customers include Holland TS to serve northern York Region, Belle River TS to serve Essex County, and Everett TS to serve southern Simcoe County. In addition, we are in discussions with a number of customers in the areas of Kingston, Durham Region, Burlington, Red Lake and a number of areas in the western part of the Province.

Other major initiatives include the development of transmission plans to support the Province's coal plant shutdown policy and the plan for a third supply line into the City of Toronto. Both of these matters are expected to be addressed in the Integrated Power System Plan being developed by the Ontario Power Authority. We are actively participating in various working groups involving key government and electricity industry stakeholders in this respect. Also related to this is our continuing work on interconnection enhancement possibilities with our neighbouring utilities. Hydro One and Manitoba Hydro have supported the continuing efforts by the Ontario and Manitoba governments in the development of the next steps for the Clean Energy Transfer Initiative that includes an increase in transmission capacity by up to 1,500 MW. Funding for this work is not currently included in our plans since it is at a preliminary stage.

In addition to the developmental investments discussed above, there is also increased spending to manage the replacement and refurbishment of our aging transmission infrastructure. Key

transmission investment areas are power equipment, protection and control equipment, ancillary systems and overhead and underground lines. Increased emphasis is placed on assets critical to support generation facilities and the unrestricted supply of energy to our customers. Some of this spending results from a review, which we undertook in 2004, of critical assets such as 500 kV lines and high voltage switchyards.

We have taken the necessary actions that support recommendations resulting from the U.S.-Canada Power System Outage Task Force initiated in response to the August 14, 2003 blackout. Follow-up studies and implementation of applicable recommendations are underway. As most of the blackout recommendations are already standard work practices at Hydro One, we require only marginal incremental funding to implement them.

Distribution

Distribution capital expenditures are focused on improving our aging distribution asset base in order to maintain or improve system reliability. Increasing investments are expected to be made within the distribution business, in particular reflecting increased wood pole replacements, feeder sectionalization and defect management. Across Ontario, we are continuing with the replacement of older distribution systems with higher voltage and more current-standard installations. In addition, we expect to continue to construct new lines and stations in response to system growth forecasts or high load relief requirements, and expect to continue our efforts to make the distribution system more efficient. Examples of some of these initiatives include a new station to serve northern King Township and various projects to reduce losses on our distribution system.

In addition, we are moving forward with initiatives to improve the reliability performance of our distribution system. Analysis concerning potential reliability improvement initiatives has revealed that cost-effective improvements can be achieved through improved maintenance practices and through improving the operability of the distribution system by adding sectionalizing capability at strategic locations. We expect to continue with the program started in 2005, ramping up the installation of sectionalizers to completion in 2008.

General

Virtually all of our net income in 2005 was earned from our regulated transmission and distribution businesses, which will remain our principal businesses. We intend to invest in network assets to maintain and reinforce our infrastructure. We expect to focus on our core work programs, making significant investments to improve asset condition, reduce reliability risk and increase customer satisfaction levels. Key investment areas include our vegetation management program through which we are striving to reduce the years between our cutting cycles and our asset replacement programs through which we are actively managing end of life replacements.

The replacement of our microwave telecommunication system with fibre-optic cable continued through 2005. This system is designed to provide a highly reliable communication infrastructure for the protection of our transmission assets and for the monitoring and control of the power system. This project, which began in 1999, is currently expected to be completed in 2006.

Financial

We aim to maximize the value of our company while maintaining an effective borrowing capability through stable credit quality and delivering stable financial returns to our shareholder.

The distribution sector in Ontario remains fragmented with 98 local distribution companies. The Province expects us not to enter into further transactions involving the acquisition or divestment of local distribution companies or distribution assets until it completes its review of the transmission and distribution sector.

Employee and Labour Relations

We expect to continue to focus initiatives on the retention of key staff and the maintenance and development of the skills and competence of all our employees.

A strategic goal of ours is to manage the demographics of our workforce, an issue which we are monitoring, as the average age of our work force is over 46 years with approximately 20 years of service. In response to this issue, a comprehensive management development program as well as a succession planning program has been implemented.

Productivity and Cost Efficiency

We remain committed to understanding and staying abreast of best utility practices in order to execute our business in the most cost effective manner possible.

We believe that cost reductions and productivity improvements can be achieved through the joint management of our transmission and distribution businesses, the Inergi LP outsourcing arrangement pursuant to which we outsourced non core functions to Inergi LP and the consolidation of our system operations functions. For example, we have consolidated our system operations functions, which were previously dispersed across Ontario, into a single operations centre located in Barrie, Ontario, while maintaining a back-up facility in Toronto, which will serve as a fully redundant back-up to the operations centre in Barrie, once refurbishment is completed. This initiative is intended to produce lower costs and better service through the introduction of more technologically sophisticated operating tools.

Given the nature of our work and extreme weather conditions encountered at times, safety is of paramount importance. We are committed to accident prevention and are striving to create an injury-free work place. We anticipate that this will not add costs to our work programs as the emphasis is on work methods and supervision, such as ensuring supervisors spend less time on administration and more time at the job site.

Significant annual savings have been achieved in recent years as a consequence of our focus on operational excellence and these savings have largely been re-invested back into our work programs or have offset additional cost pressures. Going forward, we are continuing to focus on capital efficiency and workplace productivity, but additional savings opportunities are fewer, more complex and difficult to achieve.

Our Transmission Business

Overview

Our transmission system operates at 500 kV, 230 kV and 115 kV and transmits electricity to customers consisting of 51 local distribution companies, our own distribution businesses and 66 large industrial companies that have loads greater than 5 MW. Electricity is also delivered to utilities in other jurisdictions through inter-ties. Electricity is supplied by generators, both within and outside Ontario, of which 80 in Ontario are connected directly to the transmission grid. Our transmission system serves over four million customers, directly or indirectly, and transported 157 TWh of electricity throughout Ontario in 2005. Revenues from our transmission business accounted for approximately 30% of our total revenues in each of 2004 and 2005, respectively.

Our transmission system forms an integrated transmission grid that can be divided into two components based on function. The integrated network, or bulk system, operates primarily at 500 kV or 230 kV over relatively long distances and links major sources of generation to transmission stations and larger area load centres. The area supply system operates at 230 kV or 115 kV and links the bulk system to local generators and loads, such as local distribution companies, industrial customers and our own distribution operations. Transformer stations located near load centres step down the high voltage to the level required for retail distribution systems or end-use customers connected directly to our transmission system.

Our transmission system is interconnected with the North American eastern system that is comprised of virtually all of the electric utilities east of the Continental Divide. Our transmission business owns and operates 26 synchronous inter-ties at 345 kV, 230 kV, 115 kV and 69 kV levels with New York (9), Québec (9), Michigan (4), Manitoba (3) and Minnesota (1). Due to the nature of the system, the interconnections with Québec are operated in a radial connection mode where load and/or generation is connected to either the Ontario system or the Québec system at any one time, but not to both simultaneously. This mode of operation is also required for one of the Manitoba interconnections. As a result of these interconnections, our system has a combined import capability of approximately 4,000 MW and a combined export capability of approximately 5,800 MW. In operation, the actual import and export capabilities may be restricted significantly by limitations within our or another jurisdiction's transmission networks, unscheduled power flows between interconnected systems and local load and generation patterns.

Our transmission system is currently relatively free of restrictions in its ability to supply electricity to major load centres from generating sources located across Ontario. A 500 kV system serves as the transmission "backbone" around the Greater Toronto Area with 500 kV connections to Northern Ontario, Ottawa, London and the major generating facilities. As new generation projects are assessed in Ontario, the impact on the transmission system will need to be assessed.

Transmission Assets

Our transmission assets can be divided into five functional categories: transmission stations, transmission lines, transmission operations, telecommunication facilities and other transmission assets.

Transmission Stations. Transmission stations are required to integrate the transmission lines into a network and to transform the voltage of the electricity being transmitted, depending on the voltage requirements of the end user. These stations are frequently located at points at which power from two or more transmission lines can be combined and re-routed in different directions. Their main purpose is to transform voltage and, in most cases, to allow switching capabilities between transmission lines. In some instances, facilities with only switching facilities are required. A majority of our switching stations and a few voltage transformation facilities are located at Ontario Power Generation Inc.'s facilities.

Transmission stations can be broadly classified into two categories. The first category consists of terminal stations, including switchyards located at Ontario Power Generation Inc.'s generating facilities, which are used mainly for switching and voltage transformation between the 500 kV, 230 kV, and 115 kV systems. The second category consists of customer supply stations, which are transmission stations that deliver power from the transmission system to wholesale customers. Currently, most transmission stations used for customer supply consist of paired circuits and step-down transformers that are meant to ensure that the failure of any one element will not result in a permanent loss of supply. For smaller or remote loads, a simpler station design with a single transformer or a single circuit is used.

Our transmission system includes 274 transmission stations whose components may include high voltage power transformers, power circuit breakers, high voltage switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems together with site infrastructures such as buildings and security systems.

Transmission Lines. Our transmission lines are classified into bulk power lines and area supply lines. Bulk power transmission lines are main lines delivering power from generating stations or interconnections to receiving terminal stations. Bulk power transmission lines are part of the integrated transmission network and generally operate at 500 kV or 230 kV, with a few at 115 kV. Area supply lines take power from the transmission network at the receiving stations and transmit it to customer supply transformer stations at customer load centres. The usual voltage levels of area supply lines are 230 kV or 115 kV. All of these lines are overhead except for approximately 270 circuit kilometres of underground cables in urban areas.

The transmission system includes approximately 28,500 circuit kilometres of high voltage lines whose major components consist of cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems.

Transmission Operations. All of our transmission assets and much of our distribution assets are monitored, controlled and managed from one location, our Ontario Grid Control Centre (the "OGCC") in Barrie, Ontario. At the OGCC, the integrity of our transmission and much of our distribution assets are continually monitored in real time to ensure optimal performance of the network under present and potential contingencies and provide immediate response to our customers. The OGCC is fully supported by onsite customer, engineering, facilities, training and process staff. The OGCC also coordinates our extensive outage program with the various internal stakeholders and our external customers. Required outages are assessed and coordinated to minimize their impact on system security and reliability. We are maintaining a back-up facility in Toronto, which, once refurbishment is completed, will serve as a fully redundant back-up to the operations centre in Barrie. The IESO manages the electricity marketplace and directs the operation of Ontario's integrated transmission network. Since we own and operate the

largest portion of this transmission network, we have the responsibility to ensure that the direction from the IESO is safe, optimizes our asset performance and our connection performance to our customers. Accordingly, the OGCC reviews, approves, performs and/or authorizes all switching and control actions of our transmission system assets when directed by the IESO and independently when required to ensure public/employee safety, maintain integrity of our assets and our connected customers.

Telecommunications Facilities. Our requirements for telecommunications include services for administrative data, voice and power system protection and operation. These requirements are met through the use of a wide range of our own facilities and services acquired from other telecommunications service providers. The reliability and availability of telecommunication services used in the protection and operation of our transmission system are vital to meeting our interconnection obligations, ensuring the protection of our assets and ensuring the reliability of our transmission system. Historically, if telecommunications service providers were not able or willing to provide the required services at an appropriate cost, we installed our own telecommunication facilities. These owned facilities include analogue microwave radio, fibre optic cable, power line carrier and mobile radio systems. The analogue microwave radio system is nearing the end of its useful life and we are continuing its replacement with digital fibre-optic and digital microwave system. Replacement is expected to be completed in 2006.

Other Transmission Assets. Other assets include those supporting the ongoing maintenance and operation of the transmission system, such as office and service buildings, transportation and work equipment and other office and information technology assets.

Projects Relating to Interconnection Capacity

Québec. We have a plan for a new inter-tie with the Province of Québec that would increase our inter-tie capacity by 1,250 MW. This would consist of a new two-circuit 230 kV line between the systems near Ottawa, along with AC-DC-AC conversion facilities in Québec needed to connect the two systems in a continuous manner (currently, load or generation is required to be isolated to either system for import or export). Although we have obtained the necessary regulatory approvals, Hydro-Québec has not yet advised us that it has obtained its required regulatory approvals. Accordingly, we sought an extension of our approval to construct this facility on December 3, 2003. In response to this request for a five-year extension, on March 30, 2004, the OEB issued a decision extending the expiry date of our approval by three years to December 31, 2006.

Michigan. Two of our inter-ties with the State of Michigan are currently being upgraded with the installation of 2 three phase shifting transformers and an autotransformer. We have experienced some technical difficulties, however most of this installation has been completed. The phase shifters were put into operation during emergency situations in 2005 and have been tested weekly since the fall of 2005. Full operation is pending completion of an interconnection agreement with the International Transmission Company in Michigan, which is the utility to which we are connected by these inter-ties. This equipment is intended to provide us with greater control over the use of our Michigan interconnection so as to better control transactions directly across the Ontario-Michigan border and indirectly across the Ontario-New York border.

As a result, we expect to increase our export capacity by 1,000 MW and our import capacity by 500 MW.

Manitoba. We are in the early stages of planning and development for a major new transmission line between northern Manitoba and northern Ontario, with reinforcements as necessary to allow power to flow to southern Ontario. This new transmission line would facilitate the transmission of power to be purchased by Ontario from Manitoba. To enable Manitoba to provide this supply and manage its other commitments, Manitoba Hydro would need to build new hydro-electric generation stations. The transmission line would allow Ontario to access this clean generation supply. We estimate that the earliest in-service date of this project would not be before 2012. Bringing electricity supply from the northern region of Manitoba represents an extensive and complex undertaking involving many parties.

Our Distribution Business

Overview

Our distribution system provides customers with electricity distribution services through a low voltage distribution network. During 2005, 29.6 TWh of electricity were delivered through the distribution system to approximately 1.3 million customers located in rural and urban areas (including approximately 116,000 urban retail customers located in Brampton, Ontario). The distribution system also serves 35 local distribution companies that are not connected directly to our transmission system, another 35 local distribution companies that are connected to our transmission system and 50 customers with loads exceeding 5 MW. The distribution system comprises approximately 124,500 circuit kilometres of lines operating mainly at voltages of 50 kV or less and we own 1024 distribution and regulating stations together with one transmission station. Our distribution system distributes electricity from our transmission system and 101 small embedded generators. Unlike the systems found in densely populated areas that are designed to include built-in redundancy, our distribution system supplies mainly rural areas with low population densities. To provide a cost effective service to these areas, the distribution system is configured as a largely radial system, meaning that it is configured in straight lines, rather than loops, so that an outage at any point along the line causes all customers further down the line to lose power. As a result, component failures require immediate repair or replacement prior to service restoration. Revenues from our distribution business accounted for approximately 69% and approximately 70% of our total revenues in 2004 and 2005, respectively.

Distribution Assets

The electricity distribution system is made up of three components: (i) low voltage lines connecting our transmission stations to our distribution stations and to some industrial customers and local distribution companies; (ii) distribution and regulating stations; and (iii) our distribution lines connecting the low voltage side of the distribution stations to industrial, commercial, farm, and residential customers as well as embedded local distribution companies. The three components include equipment such as poles, conductors, transformers, reclosers, protection devices and switches. Other assets include service centres and equipment, such as our transportation fleet, computing equipment and service and construction equipment.

Remote Communities

Through our subsidiary, Hydro One Remote Communities Inc., we operate 18 regulated generation and distribution systems across Northern Ontario which serve communities that are not connected to Ontario's electricity grid, the facilities of which are owned either by us or by the Ontario Electricity Financial Corporation. These remote communities include a total of approximately 3,400 customers. Electricity used by these remote communities is produced by 59 diesel generators owned by us, which are supplemented by small amounts of wind or hydroelectric generation. Pursuant to Regulation 199/02 under the *Electricity Act, 1998*, we are required, through one or more of our subsidiaries, to operate and maintain existing generation and distribution assets in, and supply electricity to, these remote communities. In December 2003, the Attawapiskat distribution system was connected to the transmission grid. Pursuant to the *Electricity Pricing, Conservation and Supply Act, 2002*, customer rates in remote communities were capped at the levels in place on November 11, 2002. See "Regulation - Distribution - Rate Orders for Remote Communities" and "Rural and Remote Rate Protection".

Our Telecommunications Business

Our telecommunications business, which is carried on by our subsidiary, Hydro One Telecom Inc., markets dark and lit fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements. This business also markets co-location space on Hydro One Networks Inc.'s microwave towers to wireless service providers.

Employees

At the end of 2005, our Hydro One Networks Inc. subsidiary had 3,904 regular (i.e., permanent) employees comprised of 312 non-represented Executive and Managerial staff, 2,741 employees represented by the Power Workers' Union and 851 employees represented by the Society of Energy Professionals. In addition, our Hydro One Brampton Inc. subsidiary had 41 non-represented regular staff, 100 employees represented by the Canadian Auto Workers and 42 employees represented by the International Brotherhood of Electrical Workers. We also had 1,174 non-regular (i.e., temporary) employees comprised of 10 Executive and Managerial staff, 539 employees represented by the Power Workers' Union, 31 employees represented by the Society of Energy Professionals and 594 employees represented by a combination of the Canadian Union of Skilled Workers (an electrical trade union) and the 16 construction building trade unions that have collective agreements with the Electrical Power Sector Construction Association. Hydro One Inc., Hydro One Remote Communities Inc. and Hydro One Telecom Inc. together have approximately 109 employees in total.

In 2005, we negotiated a three-year collective agreement with the Power Workers' Union ("PWU") which will end on March 31, 2008 and through arbitration reached a three-year agreement with the Society of Energy Professionals ("Society") which expires on March 31, 2008. The substantial majority of our employees are represented either by the PWU or Society. Furthermore, in 2005, we negotiated three-year agreements with the Canadian Auto Workers and the International Brotherhood of Electrical Workers in Brampton, both of which expire on March 31, 2008 and a three-year agreement with the Canadian Union of Skilled Workers which expires on April 30, 2008.

Outsourcing Arrangement with Inergi LP

Through our subsidiary, Hydro One Networks Inc., we entered into an outsourcing services agreement with Inergi LP as of December 28, 2001. The provision of services by Inergi LP commenced on March 1, 2002. Inergi LP is an affiliate of CapGemini Canada Inc. Under the agreement, Inergi LP provides us with customer service operations and settlements as well as supply management services, pay operations services, enterprise technology and finance and accounting services. As part of the agreement with Inergi LP, 906 of our unionized and non-unionized employees (including 770 regular and 136 non-regular employees) were transferred to Inergi LP on March 1, 2002. Under the agreement, we will continue to make available, for use by the transferred employees, the assets used by them prior to the transfer of their employment, with refurbishments as needed.

The agreement has a 10-year term and has base service fees of approximately \$1 billion over the term of the agreement. Fees are subject to decreases based on optional external benchmarking analyses every three years. Cap Gemini Ernst & Young US LLC has provided a financial guarantee as well as a performance guarantee of the obligations of Inergi LP. The performance guarantee covers the transition period in the event that the agreement is terminated. The agreement provides for rights of termination for each of the parties, including, on the part of our company, rights of early termination for convenience and upon the occurrence of specified business events. In such cases, we are obliged under the agreement to pay specified termination fees, as well as to contribute to resulting severance and other costs. In addition, upon expiration of the agreement, we have an obligation to contribute to employee severance costs, if any, up to a maximum amount of \$10 million.

Pension Plan

We established a defined benefit registered pension plan on December 31, 1999. Hydro One Inc. manages and invests the assets and liabilities of the pension fund as plan sponsor and administrator of the plan. As of December 31, 2005, there were 4,000 active members and 7,660 pensioners and disabled and deferred members. The company filed a new actuarial valuation as at December 31, 2003 with the Financial Services Commission of Ontario (FSCO), indicating that contributions to the plan commencing in 2004 would be approximately \$80 million per year, for the next three years.

Effective December 31, 1999, we established the Hydro One Inc. Supplementary Pension Plan to provide supplementary pension benefits. On October 30, 2001, this plan was amended to require the establishment of a trust for the purpose of creating security for payment of the supplementary pension benefits provided for therein. This trust was constituted as a Retirement Compensation Arrangement under the provisions of the *Income Tax Act* (Canada), and security was issued in the form of a letter of credit.

Insurance

We maintain insurance coverage, including liability, all risk property, business interruption and boiler and machinery insurance. We also maintain other insurance coverage that is required by provincial statute, which covers automobile liability, pesticide liability and aircraft liability. We do not have insurance for damage to our transmission and distribution wires, poles and towers

located outside our transmission and distribution stations caused by severe weather, other natural disasters or catastrophic events or for environmental remediation costs. See “Risk Factors”.

Real Property

The following table sets forth summary information with respect to the principal real property used in our business operations:

<u>Facility</u> ⁽¹⁾	<u>Total</u>	<u>Owned</u>	<u>Easement</u>	<u>Leased</u>	<u>Other</u> ⁽²⁾
Transmission corridors ⁽³⁾	221,530 acres	—	221,530	—	—
Transmission stations ⁽⁴⁾⁽⁵⁾	243 sites	211	1	14	17
Switching stations ⁽⁴⁾	31 sites	12	-	4	15
Transmission operating centres ⁽⁶⁾	2 sites	2	-	—	—
Distribution stations ⁽⁴⁾⁽⁷⁾	955 sites	932	1	9	13
Regulating stations ⁽⁴⁾	73 sites	69	1	2	1
Administrative and service centres ⁽⁸⁾	160 sites	119	1	35	5
Leases and Subleases ⁽⁹⁾	3 sites	-	-	3	-

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- (1) On June 27, 2002, the *Reliable Energy and Consumer Protection Act, 2002* received Royal Assent. It amended the *Electricity Act, 1998* by adding Part IX.1, which addressed the ownership and use of corridor land. Corridor land includes land in Ontario that was owned by Hydro One and was used or acquired for the purposes of the transmission system, including any abutting land. Under the Act, ownership of all corridor land was transferred to the Province and Hydro One was given a statutory easement to operate the transmission system. Hydro One also retained the obligation to incur certain ongoing expenditures related to the use of this land, including maintenance, property taxes and any future environmental remediation work that may be required by the Province. The OEB is authorized to restrict or discontinue any use of the corridor land that interferes with the transmission system. Part IX.1 was proclaimed effective December 31, 2002, resulting in the ownership of transmission corridor land with a net book value of approximately \$259 million being transferred to the Province in exchange for a statutory easement. In addition, ownership of land assets with a net value of approximately \$7 million, not then in use, was transferred to the Province and applied as a reduction of shareholder’s equity. The Province has since determined to return certain lands to Hydro One.
- (2) The Other category pertains to lands owned by Ontario Power Generation Inc. or Bruce Power, to which Hydro One has been granted access for the purposes of conducting its business. These occupations have been or will be formalized by either lease or easement.
- (3) Transmission Corridor lands totalling 49,673 acres were transferred by legislation to the Province in exchange for statutory easements effective December 31, 2002.
- (4) Comprises the total number of operating stations.
- (5) The total includes one Transmission Station site that is owned by Hydro One Brampton Networks Inc. and 210 owned by Hydro One Networks Inc. 212 sites (lands only) were originally transferred to the Province pursuant to the Act; however, all of these sites have since been transferred back to Hydro One Networks Inc. on or before December 31, 2005.

- (6) The total number of Transmission Operating Centres is comprised of 2 transmission facilities, which includes a back-up facility. All of the transmission facilities (lands only) were transferred to the Province pursuant to the Act; however, both have since been transferred back to Hydro One Networks Inc. on or before December 31, 2005.
- (7) Distribution Stations include both high and low voltage stations. There are 91 high voltage stations and the balance of the stations are low voltage. Furthermore, 15 stations sites are associated with Hydro One Brampton Networks Inc., 13 owned, one leased and one easement.
- (8) The total number of Administrative and Service Centres includes 1 owned by Hydro One Brampton Networks Inc.. Of the 87 Administration and Service Centres located outside Transmission Stations, only 1 remains to be transferred back to Hydro One Networks Inc. Of the 33 Administrative and Service Centres located within Transmission Station sites that were transferred to the Province pursuant to the Act, all have been transferred back to Hydro One Networks Inc. on or before December 31, 2005. The centres located within Transformer Stations sites are largely independent of the transformer station function, but in some instances staff operate from buildings that serve both functions.
- (9) Hydro One Telecom Inc. or its subsidiary have entered into leases or subleases for space in buildings located in Montreal, Toronto and Buffalo for its telecommunication equipment.

Environmental

Although primarily regulated at the provincial level, jurisdiction over the environment is shared by Canadian federal, provincial and local governments. As a result, we are subject to extensive federal, provincial and local regulation relating to the protection of the environment that governs, among other things, environmental assessments, discharges to water and land and the generation, storage, transportation, disposal and release of various hazardous substances.

Environmental Management System

We have an environmental management system designed to identify environmental effects of our operations and facilities and to aid in the continual improvement of our environmental performance. We continually update our environmental management system to reflect organizational changes and progress in achieving our environmental goals.

Permits, Licences and Approvals

We are required to obtain and maintain specified permits and approvals from federal, provincial and local authorities that relate to, among other things, waste disposal, drainage works and discharges to air and water.

A number of electricity projects we undertake or propose may require environmental approvals from the federal government or the use of federal lands, including reserves and other lands subject to the *Indian Act* (Canada), and will be subject to federal environmental assessment. Additional interconnection facilities with neighbouring utilities in other provinces and states require approvals and will be subject to federal regulatory review, which may include environmental assessment. Certain projects will also be subject to the provincial environmental assessment process. A significant number of our existing projects are subject to a streamlined

environmental assessment process. The scope, timing and cost of environmental assessments at either the federal or provincial level depend on the type of project and its potential for environmental impact.

Releases

Federal, provincial and municipal environmental legislation operates to regulate the release of substances into the environment through the prohibition of discharges that will or may have an adverse effect on the environment. Spills and leaks of substances occur in the course of our normal operations. We could incur fines or clean-up costs in connection with these releases. Accordingly, we have spill, leak prevention and leak mitigation programs involving the testing, replacement, repair and installation of containment systems including regasketting of transformers and sulphur-hexafluoride filled equipment. In addition, we have an emergency response capability which we believe is sufficient to minimize the environmental impact of spills and to comply with our legal obligations.

Hazardous Substances

We manage a number of hazardous substances, such as polychlorinated biphenyls ("PCBs"), herbicides and wood preservatives. In addition, some facilities have substances present which are designated for special treatment under occupational health and safety legislation such as asbestos, lead and mercury. We have environmental management programs in place to deal with PCBs and herbicides.

We continually remove PCB-contaminated materials from service and send PCB waste for decontamination or destruction. All high voltage electrical equipment containing PCBs at concentrations greater than 10,000 parts per million has been removed from service. Some equipment containing PCB-contaminated mineral oil continues to be in service, including an estimated 15,000 distribution transformers, as well as small electrical equipment components at transmission stations. PCB-contaminated mineral oil in small transmission equipment components is tested and retro filled as part of station refurbishment programs.

The Canadian federal government has proposed draft regulations that would require the phase-out of certain PCB-contaminated equipment. We are involved in discussions on these issues with the federal government and other parties. We monitor regulatory developments and have provided comments on proposed regulations that have been accepted. Our current estimate for future PCB expenditures is approximately \$47 million as of December 31, 2005 over the next 25 years. The estimated amount for 2006 is approximately \$3.6 million.

We use herbicides primarily for the control of incompatible vegetation on rights-of-way, along distribution lines and on station sites. We currently use an integrated management approach toward vegetation management using manual and mechanical cutting, together with the selective use of herbicides. Herbicides are applied in accordance with the *Pesticides Act*. As indicated below, the historical use of a specific herbicide has contaminated some of our properties and some nearby properties.

Wood preservatives are used in wood poles to protect the wood against fungi and insects and thereby extend their service lives. In the past, we have used poles which were impregnated with

pentachlorophenol. We respond to contamination problems related to pentachlorophenol migration as they arise.

Land Assessment and Remediation

We have developed a voluntary land assessment and remediation program in order to identify and, where necessary, remediate contamination related to our transmission and distribution stations, service centres and remote generating stations. It involves the systematic identification of any contamination at or from these facilities and, where necessary the development of remediation plans for Hydro One and adjacent private properties. Potential contaminants include insulating oils, substances previously used for vegetation control such as arsenic trioxide, fuel oil, gasoline, PCBs and wood preservatives such as pentachlorophenol. Phase I assessments have been completed for most of the transmission stations, service centres and remote generating stations. Limited Phase I assessments were undertaken at distribution stations given their large number and similar operating history. Site screening involving on-site soil sampling at the areas of greatest potential for contamination have been undertaken at the majority of these sites.

The inventory of land in the program is approximately 1,562 sites. The number of sites where at least one soil or groundwater sample on site was found to be above Ministry of the Environment guideline (of at least one substance of concern) is 672. We have completed the clean-up of 124 sites, which include sites where underground fuel dispensing/storage tanks were removed. Further work may be required in the event we sell or decommission any of these sites. We have developed a risk-based property ranking system to assist in establishing priorities for Phase II sampling. This system is supplemented with visual inspections of the sites and nearby receptors. Remediation and/or risk management is occurring based on Phase II results and discussions with affected property owners and regulatory authorities. The Ministry of the Environment (at the local and head office level) and local Health Departments/Medical Officers of Health are actively involved in the program.

Future costs related to the land assessment and remediation program are currently estimated at approximately \$53 million over the next ten years. The estimated expenditure for 2006 is approximately \$12 million.

Electric and Magnetic Fields

Electric and magnetic fields exist wherever electricity is used or transmitted, including electric power facilities such as transmission and distribution lines and substations, and within every building in Ontario that has electrical service. Based on current research, the consensus of the scientific community is that a public health risk from exposure to electric and magnetic fields has not been established. This is reflected in Health Canada's statement that typical exposures to electric and magnetic fields present no known health risks. We sponsor research and monitor national and international developments. Electric and magnetic fields are not currently regulated by either the federal or provincial governments and we are not aware of any current plans to regulate electric and magnetic fields.

Legal Proceedings

In connection with the reorganization of Ontario Hydro, we have succeeded Ontario Hydro as a party to various pending legal proceedings relating to the businesses, assets, real estate and employees transferred to us. We will also assume responsibility for future claims relating to the businesses, assets, real estate and employees acquired by us and arising out of events occurring prior to, as well as after, April 1, 1999. In addition to claims assumed by us, we are, from time to time, named as a defendant in legal actions arising in the normal course of business. The pending legal proceedings, which include material claims to which we are currently a defendant, are discussed below.

On September 1, 1995, Torcom Communications Inc. named Ontario Hydro as one of several defendants in a suit in the Ontario Superior Court of Justice seeking damages of \$150 million, as well as specific performance of agreements and interim injunctive relief. Torcom Communications had sought to purchase telecommunication devices belonging to a bankrupt company from a court appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom Communications claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom Communications alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995 when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not served a statement of defence. We believe that there are strong defences to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects. Torcom has not proceeded with this claim for almost 10 years.

On March 29, 1999 the Whitesand First Nation Band commenced substantially similar actions in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, the Ontario Electricity Financial Corporation, Ontario Power Generation Inc. and our company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations, electrical power lines and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the Band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. This case was consolidated with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001, as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are matters for which Ontario Power Generation Inc. would have responsibility pursuant to transfer orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand

and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects.

Health and Safety

Hydro One considers health and safety to be of paramount importance in the operation of its business. We are committed to creating and maintaining an injury-free workplace with concentrated focus on the elimination of serious injuries or close calls which have the potential to cause serious injuries. We are developing a number of programs and initiatives for accident prevention and to minimize the risk of injury to the public associated with our facilities and operations. Policies are in place for both employee health and safety and public safety.

Corporate safety performance indicators and targets have been developed to measure serious incidents, injuries arising from these serious incidents and accident severity rate. These indicators are monitored by management and by the Health and Safety Committee of the Board of Directors. Employee compensation is tied, in part, to success in achieving annual safety performance targets. An effective early and safe return to work process has allowed us to ensure that, when injuries occur, employees recover and return to the workplace as soon as possible.

Several programs and practices have been implemented to improve our safety performance. Actions currently underway include increasing the field presence of supervisors, ensuring clear and consistent standards for work performance, improving safety communications and better understanding the human decision-making process to improve performance. Work site inspections and a safety rotation/mentoring program involving the major lines of business are also contributing to a safer workplace by identifying hazards and ensuring that proper barriers are in place before work is undertaken. Our incident investigation process allows us to learn as much as possible from incidents in order to develop improvements to job planning and prevent recurrences.

Hydro One has integrated the management of health and safety into a single health, safety and environment management system. Effective risk assessment and management are key elements to the successful minimization of risk and safety performance improvement. Within the organization, hazards have been identified and controls implemented to mitigate these risks.

REGULATION

The Statutory and Operating Framework

General

The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended from time to time, primarily establish the broad legislative framework for Ontario's competitive electricity market. The *Electricity Act, 1998* implemented the fundamental principles of the restructuring of Ontario's electricity industry, enabling the implementation of open non-discriminatory access to

transmission and distribution systems. The *Ontario Energy Board Act, 1998* expanded the jurisdiction and mandate of the OEB to include regulation of the electricity and natural gas markets. Both statutes have been amended several times, as discussed in the sections below¹.

Since May 1, 2002, the date of Open Access, the prices of electricity in Ontario began to be determined by market forces in the wholesale electricity market administered by the IESO. The IESO is the centralized independent electricity system co-ordinator responsible for maintaining the security and reliability of electricity supply in Ontario and for directing the operations of the IESO controlled grid. The IESO itself is licensed by the OEB and funded through fees which are approved by the OEB and levied on all market participants. See “Regulation – Contractual Arrangements, Codes and Licences – Operating Agreement with the IESO.”

Market participants may buy and sell electricity from the wholesale spot markets, administered by the IESO. Alternatively, they may contract such transactions with each other, albeit with the obligation to schedule these transactions with the IESO.

Electricity consumers in the retail market also have a choice of suppliers. They may contract with any retailer of their choice or they may continue to be provided with standard supply service by their incumbent distributor. In either case, the distributor is obliged to continue to deliver electricity to them as long as they are connected to that distribution system. See “Regulation - Contractual Arrangements, Codes and Licences – Electricity Industry Codes.”

Each distributor, including our company, continues to have an obligation to connect and supply customers in accordance with the *Electricity Act, 1998* and the conditions of its distribution licence and rate orders. On May 1, 2002, we began to provide customers connected to our distribution system who did not choose a competitive retailer (our standard supply customers) with electricity in accordance with the provisions of the OEB’s Standard Supply Service Code. See “Regulation – Contractual Arrangements, Codes and Licences – Electricity Industry Codes”. As a result of the *Ontario Energy Board Amendment Act (Electricity Pricing)*, 2003 and associated regulations, on April 1, 2004, the fixed price for the provision of this service to low volume and designated consumers was changed to a tiered pricing structure of 4.7 cents per kWh for the first 750 kWh and 5.5 cents per kWh thereafter. This price changed to 5.0 cents per kWh for consumption levels up to the seasonal consumption threshold and 5.8 cents per kWh as a result of the regulated price plan, which came into effect on April 1, 2005, to remain effective through March 31, 2006. See “Regulation – Rate Orders and Related Issues for Hydro One’s Business”.

In May, 2005, the OEB completed a consultation and review process which culminated in the issuing of the 2006 Electricity Distribution Rate Handbook. This handbook provided the framework for the OEB’s review of electric distribution utilities’ revenue requirements so that rates may be re-established based on this historical average or forecasted need for implementation by May 1, 2006. See “Distribution - Current Rate Orders and Distribution Rate Structures” and “Rate Orders for Remote Communities.” Cost allocation issues are being addressed by a working group which began work in September, 2005. They expect to have a

¹ Amending statutes include: *Reliable Energy and Consumer Protection Act, 2002 Electricity Pricing, Conservation and Supply Act, 2002, Ontario Energy Board Amendment Act (Electricity Pricing), 2003, Electricity Restructuring Act, 2004 and Ontario Energy Board Consumer Protection and Governance Act, 2003.*

filing model available during the summer of 2006, enabling distributors to subsequently file new cost allocation studies in the fall of 2006.

In addition, legislative changes created the Ontario Power Authority (“OPA”), an independent, non-profit corporation which is mandated to:

- assess the adequacy and reliability of electricity resources for the medium and long term
- forecast future electricity demand and potential for conservation and renewable energy
- prepare an integrated system plan for generation, transmission and conservation
- lead the planning and co-ordination of electricity conservation measures through a Conservation Bureau
- procure new supply, and initiate the development of transmission and demand management programs by competition or by contract
- assist the Province in achieving alternative and renewable energy goals

The OPA has powers to raise funds, including borrowing from the Province, and is expected to be self-financed through fees approved by the OEB. Each director of the OPA holds office as an independent director and not as a representative of any class of persons in the industry.

The role of the IESO has also changed. The IESO relinquished responsibilities for medium and long-term forecasting to the OPA and for market surveillance to the OEB. Through its billing and settlement systems, the IESO is required to ensure that, over time, participants pay the true cost of electricity. It retains authority over the:

- operation of the wholesale system and the operation and reliability of the power system
- short-term forecasting
- ensuring compliance with the market rules

In its enhanced role, the OEB is responsible for:

- promoting economic efficiency and cost effectiveness in electricity generation, transmission and distribution and demand management
- approving the OPA’s integrated power system plans and procurement processes
- regulation of payments to generators of regulated facilities
- regulation of all elements of electricity price, including generation, for low volume and designated consumers

The role of electricity distributors has also been expanded to permit the undertaking of energy management. The legislation has been amended to promote the expansion of electricity supply and capacity, facilitate load and demand management, encourage conservation and efficiency and regulate prices in parts of the electricity sector. The key features of the legislative amendments which affect Hydro One’s businesses, include:

- The continuation of a wholesale market structure for the purchase and sale of electricity in Ontario
- Withdrawal of the requirement for prior Ministerial approval of distribution rate applications to the OEB
- Explicit authority of the Minister of Energy to set targets for conservation and renewable energy and guidelines for supply diversity

Further changes are contemplated arising from Bill 21, *The Energy Conservation Leadership Act, 2005*, introduced on November 3, 2005. This Bill lays the groundwork for the Provincial Government's smart metering initiatives by providing for the establishment of a smart metering entity (SME), establishing distributors' obligations and also enhances the OEB's capability to support the initiative through its regulatory instruments.

Contractual Arrangements, Codes and Licences

Operating Agreement with the IESO

Under the *Electricity Act, 1998*, the IESO is required to enter into agreements with transmitters giving it the authority to direct the operations of the transmitters' systems. On June 8, 2001, we signed our 10 year operating agreement with the IESO, which sets out the specific responsibilities of both parties relating to the provision of transmission service. The agreement, among other things, identifies our facilities that will be included in the IESO controlled grid; provides that the IESO will direct the operation of the facilities of our subsidiary, Hydro One Networks Inc.; defines the respective obligations of Hydro One Networks Inc. and the IESO regarding the operation of these facilities; provides for co-ordination between Hydro One Networks Inc. and the IESO of modifications or additions to our transmission facilities; establishes the terms and conditions relating to information sharing and confidentiality, monitoring and telecommunications facilities, and the delineation of accountabilities for protection systems; and addresses issues of liability and indemnification obligations.

By contrast, the distribution portion of Ontario's network is not directed by the IESO and remains subject to the operational control of local distribution companies in accordance with the regulatory framework.

Hydro One's Relationships with Other Market Participants

Generators, local distribution companies and customers directly connected to our transmission system must enter into agreements with us to ensure reliable connection service in conformity with the Transmission System Code established by the OEB.

Some market participants, such as generators and large load customers embedded within distribution systems, are connected to the wholesale market through lines and facilities that are defined as "distribution" and owned by local distribution companies. At a minimum, under the *Electricity Act, 1998*, local distribution companies must provide non discriminatory access for eligible generators and customers to the wholesale markets administered by the IESO. The local distribution companies must advise the IESO of any conditions in their distribution system that

may affect the ability of embedded generators and loads to participate in the broader IESO administered markets.

Electricity Industry Codes

The OEB has approved the Affiliate Relationships Code for Electricity Distributors and Transmitters, the Standard Supply Service Code, the Distribution System Code, the Transmission System Code, the Retail Settlement Code and the Electricity Retailer Code of Conduct. These Codes and requirements prescribe minimum standards of conduct and standards of service for transmitters, distributors and retailers in the electricity market.

The Affiliate Relationships Code for Electricity Distributors and Transmitters establishes the standards and conditions for the interaction between electricity distributors or transmitters and their affiliated companies. Accordingly, our subsidiaries through which we transmit and distribute electricity are subject to this Code. Among its primary purposes, this Code is intended to minimize the potential for a distributor or transmitter to cross subsidize competitive or non monopoly activities.

The Standard Supply Service Code governs the conduct of distributors, including our company, in their provision of standard supply service. Under the Code, a distributor's rates for standard supply service are approved and fixed by the OEB and consist of the price for electricity and an administrative charge which is intended to allow the distributor to cover its costs of providing the service. Our rates for standard supply service were approved by the OEB. As a result of the legislative changes, on April 1, 2005, our prices for standard supply service moved from regulated levels to the RPP. On June 16, 2005, a revised Standard Supply Service Code was issued to accommodate these changes. See "Rate Orders and Related Issues for Hydro One's Business." Each of the Transmission System Code and the Distribution System Code sets the minimum conditions that a transmitter or distributor, respectively, must meet in carrying out its obligations to transmit or distribute electricity.

The Transmission System Code applies to all transactions and interactions between a transmitter and distributors, generators and consumers of electricity directly connected to the transmission system. On August 20, 2005, the OEB completed a three-year review of the Transmission System Code and related matters, following which it issued a revised Code. This revised Code implements the OEB's June, 2004 decision on principles governing issues relating to transmission system by-pass, available capacity, cost responsibility, economic evaluation and contestability. This decision allows customers to build new connections that Hydro One would otherwise have owned and operated. Compensation to Hydro One for acquired or by-passed assets is limited to the asset's net book value. However, existing generation cannot re-connect to cause by-pass of transmission tariffs (as this does not support new generation facilities in the Province). The decision also accepts that rates may be increased as a result of such by-pass. Hydro One has undertaken initiatives and a compliance assessment process which reflects the Code changes.

The Distribution System Code applies to all transactions and interactions between a distributor and all retailers, generators, distributors, transmitters and electricity consumers who use the distributor's distribution system. Following a consultation with stakeholders in 2003, the OEB amended the Distribution System Code to clarify and streamline the process and requirements

for connections, with changes coming into effect in March, 2004. The OEB also amended the Distribution System Code to include requirements for electricity consumer security deposits to ensure consistent and equitable treatment across distributors, coming into effect in July, 2004. The Code was further revised to include an obligation on distributors to provide customers with standard safety information upon disconnection. During 2005, the OEB undertook three amendments to the Distribution System Code. These changes were required to accommodate the Ministry of Energy's standard offer program (a program to promote small generators using clean or renewable resources that are embedded in distribution systems) in concert with the OPA's initiative in this area. The intent was to address net metering as required for eligible generators and to ensure clarity and uniformity in its processes related to connections and expansions. The Retail Settlement Code outlines the obligations of a distributor with respect to its relationships with other retail market participants and its role as retail market settlements administrator. This Code is supported by the Electricity Distribution Rate Handbook to ensure that, subject to credit risk, distributors will not make or lose money in undertaking retail market settlements. In particular, the distributors served by our company's distribution system may have the option of receiving electricity from us rather than purchasing from the wholesale market participants. In this event, we would require increased working capital to cover accounts receivable and increased ongoing costs and would expect to recover these costs through our distribution rate order. On April 1, 2005, a revised Retail Settlement Code was issued to reflect the changes required by the RPP structure. See "Rate Orders and Related Issues for Hydro One's Business."

Electricity Industry Licences

During 2003, the OEB undertook a review of the licences of all electricity transmitters, distributors and generators in Ontario. The new licences have a 20-year term and incorporate the reporting and record-keeping requirements in accordance with the OEB's Electricity Reporting and Record Keeping Requirements. New licences for all of our regulated businesses were issued in 2004.

Transmission Licence

The terms and conditions of our new transmission licence are essentially the same as those in the transitional licence.

The following are the key conditions of our transmission licence:

- ***Obligation to Enter into Agreement with the IESO*** — We are required to enter into the operating agreement with the IESO, providing for the IESO's direction of the operation of our transmission system. On June 8, 2001, we signed our operating agreement with the IESO. See "Regulation – Contractual Arrangements, Codes and Licences – Operating Agreement with the IESO".
- ***Non-discriminatory Access*** — If a generator, distributor, retailer, wholesaler or customer requests that we convey electricity using our transmission system, subject to capacity constraints, we must make an offer to convey electricity on behalf of the applicant consistent with the applicable Market Rules and the Transmission System Code.

- ***Obligation to Connect*** — We may not refuse an offer to connect to our transmission system which has been made in accordance with the terms of our transmission rate order, the Market Rules and the Transmission System Code unless we are permitted to do so by the OEB, the legislation or any codes, standards or rules with which we are obligated to comply as a condition of our licence. We must respond to a request for connection within 30 business days in compliance with published connection procedures.
- ***Obligation to Maintain System Integrity*** — We must maintain our transmission system to the standards established in our agreement with the IESO, the Market Rules and any other recognized industry operating or planning standard which has been specified by the OEB.
- ***Transmission Rates*** — We may not impose charges for the transmission of electricity or connection to our transmission system except in accordance with our transmission rate order.
- ***Separation of Business Activity*** — Our transmission business must separate its financial records from those of any other business of Hydro One.
- ***Expansion of the Transmission System*** — We may not construct, expand or reinforce our transmission system or make an interconnection except in accordance with the legislation, regulations, Transmission System Code and the Market Rules. The OEB may require us to expand or reinforce our transmission system if it determines that there is a threat to security, reliability or integrity of the system. We were required to and did use our best efforts to expand our inter-tie capacity to neighbouring jurisdictions by 2,000 MW by May 1, 2005. Approvals for some projects are in place but limited progress has been made to date on adding capacity. The OEB has been kept informed of our progress and we have updated the OEB since May 1, 2005 to enable their assessment of our efforts.
- ***Information Disclosure*** — We are required to maintain records, provide the OEB with information it may require from time to time and inform the OEB of any material change in circumstances no more than 20 days after the date of occurrence.
- ***Restrictions on Provision of Information*** – We are restricted in our use and disclosure of information pertaining to consumers, retailers, wholesalers and generators. We must obtain consent for disclosure of such information, except in certain specified situations and inform such parties of the conditions under which their information may be disclosed without their consent.

Distribution Licences

The terms and conditions of our three distribution licences are similar to the terms and conditions of our transmission licence described above. In addition, these licences:

- ***Separation of Business Activity*** – require the distribution business to keep its financial records separate from those of the transmission business;

- ***Distribution Rates*** – create an obligation to charge rates in accordance with an order of the OEB and in accordance with the methods or techniques set out in the Electricity Distribution Rate Handbook, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code;
- ***Code Compliance*** – require compliance with the Retail Settlement Code and the Affiliate Relationships Code for Electricity Distributors and Transmitters;
- ***Commodity Rebates*** – prescribe the manner by which we must pass through any rebates from Ontario Power Generation Inc. to customers; and
- ***Obligation to Connect and Serve*** – impose the obligation on our distribution business to connect a building to our distribution system under prescribed circumstances, and to sell electricity or ensure electricity is supplied to every person connected to our distribution system, in accordance with our distribution rate orders and the Standard Supply Service Code, and to sell electricity to consumers consistent with the terms and conditions of these instruments.

Rate Orders and Related Issues for Hydro One's Businesses

The OEB approves both the revenue requirements of and the rates charged by our regulated businesses. The rates are designed to permit our businesses to recover the allowed costs and to earn a specified annual rate of return on the average common equity.

The term “utility rate base” refers to the investment in regulated operations (consisting of gross plant in service, less accumulated depreciation, plus necessary working capital and excluding construction work in process). Utility rate base is used to determine the capital structure for our regulated businesses, enabling a determination of approved financing charges and return on common equity for them. In 1999, the OEB approved a capital structure for our regulated businesses of 60% debt with a weighted average cost of approximately 7.7%, 4% preferred equity with a 5.5% dividend rate and 36% common equity.

The regulation of utility charges has undergone considerable change since the market opened in May 2002. The commodity prices have changed from market level to a fixed 4.3 cents per KWh for low volume users and designated customers under the *Electricity Pricing, Conservation and Supply Act, 2002* to 4.7 cents per KWh for the first 750 KWh consumption and 5.5 cents thereafter under the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* on April 1, 2004. On April 1, 2005, the OEB implemented the new regulated price plan (“RPP”) structure for low volume and designated customers. The RPP maintained the current two-tiered pricing structure but set new prices for electricity of 5.0 cents per kWh for the first 750 kWh and 5.8 cents per kWh thereafter. It also introduced different seasonal consumption thresholds for residential customers. This process began on November 1, 2005 with the threshold rising from 750 kWh to 1,000 kWh per month through April 30, 2006 when it will lower to 600 kWh per month from May 1 through October 31, 2006. The rates for the remaining customers have continued to be determined by market or commercial contracts for the entire period.

While transmission rates set in 1999 have remained basically unchanged, distribution rate regulation changes have been disruptive. The distribution rates had phased in increases in

October 2001 and May 2002. Further distribution increases approved for May 2003 as well as rates for low voltage customers were halted by *Electricity Pricing, Conservation and Supply Act, 2002*. This regulation froze rates for all distributors including our remote customers at the November 11, 2002 level. Distributors and transmitters could not apply to the OEB for changes in rate orders without the approval of the Minister of Energy. The Minister's approval was also required for new market rules and changes to existing rules. Under the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* distributors were allowed to commence recovery over a four-year period, of the costs and revenue losses that have been deferred, commencing with market transition. At the same time, the requirement to obtain Ministerial approval to make a transmission rate application was removed. The *Electricity Restructuring Act, 2004* removed the requirement to obtain Ministerial approval for distribution rates.

The Province also indicated that, subject to regulations and OEB direction, local distributors including Hydro One's distribution business, would be allowed to recover their next installments of market adjusted revenue requirements ("MARR"), conditional on their re-investing the equivalent of one year of these revenues in conservation and demand management initiatives. Hydro One received approval of its Conservation and Demand Management Plan ("C&DM Plan") on behalf of Hydro One Networks Inc. on February 18, 2005 on the condition that planned spending on smart meters for 2006 (\$7.1 million) be re-directed to other projects. On November 1, 2005, the revised plan was approved as filed, enabling total expenditures of \$39.5 million. On February 18, 2005, Hydro One Brampton Networks Inc.'s plan for \$3.2 million in C&DM spending were approved as filed. Hydro One Remote Communities Inc.'s proposed C&DM plan was also given interim approval, as requested, on February 2, 2005.

Transmission

Current Rate Orders and Review of the Existing Transmission Rate Structure

For 2000, the rate order issued by the OEB for our transmission business (effective on April 1, 1999) approved an annual revenue requirement of \$1.2 billion. In determining the revenue requirements, the OEB approved a utility rate base of \$5.7 billion, a level of net costs and expenses of \$549 million, and a level of payments in lieu of corporate income tax of \$139 million for 2000.

On January 15, 2001, the OEB issued its rate order, which included approved transmission rates for our company. Subsequently, it decided to establish a process involving all electricity transmitters within Ontario to develop uniform transmission rates that would apply to all transmission customers. On April 30, 2002, the OEB approved transmission rates that apply uniformly to the hourly peak demand at any transmission delivery point in Ontario. Our approved revenue requirement and load forecast remain unchanged as a result of the adoption of uniform rates. In addition, the OEB's adoption of the uniform transmission rate reduces the financial incentive for customers to seek an alternative transmission provider. The IESO collects transmission revenues for our company and remits these to us on a monthly basis.

On October 26, 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB is to consider options to track net income excesses or deficiencies from OEB-approved returns for the period from

January 1, 2006 until the revised transmission rates are implemented. The options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism.

On November 23, 2005, we proposed to the OEB an earnings-sharing mechanism that would result in excess or deficient earnings being tracked. Excess earnings would be returned to customers in the form of transmission system expansion projects that are critical to the economic health of Ontario and secure operation of the system. The approval of any earnings sharing mechanism could have a significant impact on our net income. Specifically, a 1% change in the return on deemed common equity of the transmission business, would affect our net income by about \$22 million. We participated in an oral hearing on this matter and we anticipate a decision from the OEB in the first quarter of 2006. We also anticipate submitting evidence following the issuance of the Ontario Power Authority's Integrated Power System Plan in the summer, in preparation for a transmission rate hearing expected to be held later in 2006.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters such that the share of revenue allocated to Great Lakes Power Ltd. increases to reflect its approved revenue requirement. As a result, our share of overall provincial transmission revenue will decrease by approximately \$13 million per year beginning in 2006.

Current transmission rates are based on the fully allocated cost associated with providing each of the following three transmission service elements:

- ***Network services*** — the transmission network is the integrated part of our high voltage transmission system that is shared by all users and includes all 500 kV facilities, the 230 kV and the 115 kV facilities that can be classified as commonly used;
- ***Line connection services*** — connection facilities are the radial parts of our high voltage transmission system, which are dedicated to serving a single customer or generator or a group of customers or generators. Transmission line connection facilities are the radial high voltage transmission lines connecting the transformer to the network; and
- ***Transformation connection services*** — the transformation connection assets consist of the high voltage transformation facilities that step down voltages from transmission levels to distribution levels to supply customers.

In addition, electricity exports from Ontario are levied an export charge for transmission of one dollar per MWh.

Competition

Under the *Ontario Energy Board Act, 1998*, any licensed competitor can apply to the OEB for approval to build transmission network facilities in Ontario. The OEB's adoption of the uniform transmission rate reduces the financial incentive for customers to seek alternative transmission.

Customers historically had the option to build and own their own transmission connection facilities and thereby avoid paying our connection charge. Only a few large industrial customers

and local distribution companies chose to do so, likely because of the significant costs of construction. Under the new regulatory framework, in addition to avoiding our connection charge, local distribution companies that own their transmission connection facilities can include these assets in their rate base and earn a regulated return. Customers will generally, however, continue to have the option to have their new connection facilities incorporated within our existing transmission transformation and line pools or to build and own their new connection facility. We expect to continue to maintain and restore our existing connection assets, as well as bid on the construction and ownership of new facilities.

By-pass

By-pass occurs when we have invested in the provision of transmission facilities to a customer which then obtains all or part of its transmission services in another manner or takes action to avoid its use of transmission services before the rates collected have paid for the investment. Recovery of the remaining costs for the stranded facilities then necessitates higher transmission rates from the remaining customers.

In its January 2001 decision respecting transmission rate design and cost allocation, the OEB addressed the issue of by-pass where a load customer installs a generator to serve all or part of its load. The OEB decided that customers would be assessed line and transformation connection charges based on their total demand for electricity, or gross load. However, given the desire to encourage new generation and the growth anticipated in the usage of the network (which would hold us harmless from the effects of stranding), customers would be assessed network charges based on their net load. In effect, customers who generate electricity on-site can save the network charges otherwise applicable to their purchase of electricity generated by third parties. The decision to assess line and transformation connection charges based on gross loads means that on-site generators bear a portion of the costs associated with Ontario's transmission infrastructure, thereby mitigating the potentially negative effect of on-site generation on our transmission business.

Although the January 2001 decision clarified the by-pass situation and the charges to be applied to load customers which install generation, two companies, Abitibi-Consolidated Company of Canada Limited and CASCO Inc., requested relief from the obligation to pay transmission charges. Despite our opposition, on September 4, 2003, the OEB awarded both companies net load billing on their line connection and network transmission rates with retroactive application to May 1, 2002. Despite having refunded \$2.8 million in total to the two companies, the OEB has disallowed a deferral account to record this amount for future recovery.

In August, 2005, following an extensive consultation process, the OEB issued a revised Transmission System Code, which implements its June 2004 decision on principles relating to transmission by-pass, among other things. See "Regulation – Contractual Arrangements, Codes and Licences – Electricity Industry Codes".

Facilities Applications

With the creation of the OPA, the process for seeking approval of future large transmission projects has changed. Such projects will have to be factored into an Integrated Power System Plan, which the OPA must submit to the OEB for approval. Once approved, transmitters are

required to conduct an environmental assessment, as well as apply to the OEB for leave to construct. Cost recovery of the facility then needs a final approval from the OEB as part of a transmission rate application. To develop recommendations for improving the efficiency with which such project approvals may be obtained, the Province has begun an initiative, to which Hydro One is contributing.

On August 26, 2005, the OEB also announced its intent to develop filing requirements for transmission infrastructure investment, citing the need to clarify the approach for evaluating the costs and benefits of such investment. The OEB has stated that following the conclusion of this process, it will likely review the relationship between rate recovery, leave to construct applications and the OPA's IPSP. The filing requirements were originally planned for issue by the end of 2005, however, this work is still ongoing.

On December 3, 2003, we applied to the OEB for approval to construct a new transformer station at our current Parkway location ("Parkway TS") and a 6.5 km transmission line along an existing right of way from Parkway TS to Richmond Hill Transformer Station in Markham. The OEB approved the application on December 24, 2003. Construction began in March, 2004 and the new transformer station was placed in service in April, 2005.

During 2005, Hydro One received the OEB's approval for three other transmission projects:

1. Hydro One received approval on March 11, 2005 to construct two new 2.2 km underground 230 kV cable circuits between our John Transformer Station and Esplanade Transformer Station in downtown Toronto. Construction began in July 2005 with a planned in-service date of October, 2007.
2. Hydro One received approval on July 8, 2005 to construct 76 km of 230 kV line from our Allanburg Transformer Station in the Niagara area to our Middleport Transformer Station in the Hamilton area. This project will add 800 MW of transfer capability from Niagara inter-ties to Ontario. Construction began in July 2005 with a planned in-service date of October, 2007.
3. A joint application with DeBeers Canada Inc. and Five Nations Energy Inc. to construct transmission facilities that will connect DeBeers' planned Victor Mine to the transmission grid was approved by the OEB on July 18, 2005. We expect to apply for leave to construct other transmission projects in 2006. Although we received the needed regulatory approvals from the OEB for an increase of our inter-tie capacity with Hydro-Québec, Hydro-Québec has not received the equivalent approval from the Régie de l'énergie. In response to our December 3, 2003 request for a five-year extension to this approval, the OEB, on March 30, 2004, issued a decision extending the expiry date by three years to December 31, 2006.

The Reliable Energy and Consumer Protection Act, 2002

In June 2002, the Province enacted the *Reliable Energy and Consumer Protection Act, 2002*, which transferred the ownership of all transmission corridor land to the Province effective December 31, 2002. Our company retains the statutory right to use and expand the use of these corridor lands for transmission and distribution purposes. The Province has since determined to return certain lands to Hydro One.

Current Rate Orders and Distribution Rate Structure

Our 1999 rate order, effective April 1, 1999 through to March 31, 2001, approved an annual revenue requirement of \$611 million for 2000 for our distribution business. In determining this revenue requirement, the OEB approved a utility rate base of approximately \$2.4 billion. For the purposes of determining the revenue requirement, the OEB approved a capital structure for our regulated businesses of 60% debt with a weighted average cost of approximately 7.7%, 4% preferred equity with a 5.5% dividend rate and 36% common equity and a rate of return on deemed common equity of 9.88%.

Distributors' initial May 1, 2000 applications for unbundled distribution rates reflected a market-based rate of return as well as a higher cost of power which would have resulted in significant increases in customers' electricity bills. In accordance with Ministerial and OEB direction to all distributors to re-file their applications with a plan to protect customer interests, we filed an amended application, which sought to limit increases paid by consumers to 4% commencing on October 1, 2001, 2.8% commencing on March 1, 2002 and 2.8% commencing on March 1, 2003. On August 30, 2002, the OEB issued its final rate order for our distribution business. The approved revenue requirements totalled \$646 million effective October 1, 2001, \$694 million effective March 1, 2002 and \$742.3 million effective March 1, 2003, to be collected from retail rates, miscellaneous charges and low voltage charges. The March 2003 increase was not implemented as a result of the rate freeze implemented under the *Electricity Pricing, Conservation and Supply Act, 2002*. This Act also suspended the recovery of low voltage costs (estimated at \$26 million per year) and froze distribution rates for our acquired customers at the first stage of commercial return.

With the introduction of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, distributors were able to start recovering certain distribution regulatory assets in their rates on an interim basis, beginning March 1, 2004. On January 28, 2004, we filed an application with the OEB, to adjust our distribution rates for interim recovery of the regulatory assets identified in the *Electricity Pricing, Conservation and Supply Act, 2002* for the first year of the four year recovery period commencing April 1, 2004. On December 9, 2004, the OEB issued its final decision which approved a total of \$144 million for recovery, comprising account balances in Hydro One's retail settlement variance accounts, market ready costs, secondary environmental deferral accounts, deferred low voltage costs and other regulatory assets. As a result of this successful regulatory recovery, we recorded an increase in our regulatory asset balance, which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue. The OEB disallowed \$5 million for the delay in MARR and payments in lieu for acquired distributors, about \$5 million for costs related to the implementation of the *Electricity Pricing, Conservation and Supply Act, 2002* and also, approximately \$2 million of the market ready costs. Hydro One's application for rate adjustments to recover the approved amounts, coincident with the implementation of changes related to the recovery of MARR adjustments that were delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, and changes in the pricing of the electricity commodity were approved by the OEB for implementation on April 1, 2005.

On August 17, 2005, Hydro One filed a Distribution Rate Application seeking approval for a \$160 million increase in the 2006 revenue requirement for our distribution business. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. Hydro One is requesting the full revenue requirement to recover

all costs as well as recovery of regulatory assets incurred from January 1, 2004 to April 30, 2006. On average, customers would see an increase of 6% on their monthly bills starting May 2006. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006 to enable revised rates to be implemented on May 1, 2006.

In August, 2005, Hydro One filed a distribution rate application seeking approval for a \$3 million increase in the 2006 distribution revenue requirement of Hydro One Brampton Networks Inc. On average, customers would see an increase of 1% on their monthly bill starting May 2006. This rate application follows a separate process with the OEB independent from the Hydro One Networks' distribution application. Hydro One also submitted on October 26, 2005, an application for distribution rates on behalf of our remote customers. See "Rate Orders for Remote Communities".

Miscellaneous Rate Applications

On November 15, 2005, Hydro One applied to the OEB for approval of rates applicable to distributed electricity generator customers of Hydro One Networks Inc. on an interim basis until we have sufficient information to file for approval of rates based on a cost allocation study. These rates, which comprise the volumetric portion of the charge only, are intended to assist in removing a financial barrier to the implementation of distributed generation in the Province. The identified shortfall from the loss of the monthly service charge revenue is proposed to be collected in a deferral account for future disposition. We anticipate a decision in the second quarter of 2006.

On April 26, 2005, Hydro One received OEB approval for a rate amendment affecting embedded customers connected to the Hydro One Distribution low voltage system that are supplied from multiple delivery points at a single transformation station and who pay retail transmission charges. The amendment allows the aggregation of demand for such customers and is intended to align the basis on which they are charged retail transmission rates to with that employed by the IESO in charging transmission rates to wholesale transmission customers supplied from multiple delivery points at a single transformation station. The reduction in charges to customers will be recovered through the retail settlement variance accounts.

On December 20, 2004, the OEB approved Hydro One's time of use rate pilot program, as an aspect of our Conservation and Demand Management program. Customers are eligible for these time of use rates if their electricity consumption in the off-peak period is at least twice that during the on-peak period.

Rate Orders for Remote Communities

Hydro One Remote Communities Inc.'s business is exempt from a number of sections of the *Electricity Act, 1998* which relate to the competitive market. For example, we continue to apply bundled rates to customers in remote communities. Rates for our remote customers were increased on June 1, 2002, to reflect the 0.7 cent per kWh increase in the wholesale power rates applicable to the rest of Ontario on June 1, 2001.

We had applied to the OEB on March 11, 2002 to increase our remote customer rates to align with other increases in our distribution rates. We proposed to follow the intent of the Electricity

Distribution Rate Handbook and adopt a modified performance based regulatory approach. However, as the application was underway at the time that the *Electricity Pricing, Conservation and Supply Act, 2002* was passed, the proceeding was terminated. Rates which had been approved for implementation on an interim basis on June 1, 2002 became final.

On December 20, 2004, we applied to the OEB for interim approval of our conservation and energy efficiency plan with planned expenditures of \$300,000 for a one-year program. This application was not intended to change the current rates for our remote customers in 2005, but instead, to implement a deferral account, with disposition of this account to be addressed in the next rate application. The plan was approved on an interim basis, as filed, on February 2, 2005.

On October 26, 2005, we applied to the OEB for approval of our revenue requirement and new electricity rates for our remote customers for implementation on May 1, 2006. This application requests approval of a revenue requirement of \$35.5 million, the establishment of Rural and Remote Rate Protection at its current level, adjustments to reflect anticipated fuel cost increases in 2006 and the cost of an on-going C&DM program, inclining block conservation rates for our Non-Standard A Residential and General Service customers, as well as exemptions from certain sections of the Distribution System Code

Rural and Remote Rate Protection

In approving electricity rates for a distributor which delivers electricity to rural or remote consumers, the OEB is required to provide rate protection for prescribed classes of consumers, including those who received rural rate assistance prior to April 1, 1999, by reducing the rates that would otherwise apply.

From April 1, 1999 until the present, the amount of rate reduction for rural consumers who occupy rural residential premises is \$127 million per year less the specific amounts established for certain specified municipalities and distributors in three former remote communities.

Our remote customers received a rate reduction in the amount of \$21 million for 2002, 2003, 2004 and 2005 based on the amount that they received in 2001. The amount to be set for 2006 is expected to be set by the OEB according to the rules set out in accordance with the regulations under the *Ontario Energy Board Act, 1998*.

Under the *Ontario Energy Board Act, 1998*, a distributor is entitled to be compensated for lost revenue resulting from the rate protection regime, and all consumers are required to contribute towards the amount of any compensation to the distributors, such as our company, for rate protection. As of May 1, 2002, the amounts required to compensate the distributors were collected by the IESO and paid to us for distribution in accordance with the regulation under the *Ontario Energy Board Act, 1998*. The OEB calculates the charge to be collected by the IESO based upon the latter's forecast of the number of kilowatt-hours of electricity that will be withdrawn from the IESO-controlled grid. We maintain a variance account to track any surplus or deficit in the amount received from the IESO and from the \$127 million prescribed amount.

Hydro One Remote Communities Inc.'s business is run on a break even basis. As a result, any net earnings or loss in the year, including rural and remote rate protection amounts, will be deferred in a regulatory variance account for inclusion in the calculation of future customer rates.

Competition

Under the *Ontario Energy Board Act, 1998*, there are instances in which it is appropriate for one distributor to transfer its customers to another distributor. The acquiring distributor is required to obtain amendments to its licence authorizing it to serve in a specific area, but not with exclusive distribution rights to it. The OEB convened a generic hearing in December 2003 to determine the principles which will apply to such licence amendment applications. On February 27, 2004, the OEB issued its decision, with clear principles and filing requirements to be followed for service territory amendment applications. To date, on such applications, Hydro One has co-operated with other distributors on a case-by-case basis to determine the most efficient supplier and has not had to contest any such applications.

In July, 2005, as a result of three applications by distributors, another generic proceeding was convened by the OEB to determine issues relevant to inter-utility share acquisitions and amalgamations. In a decision issued on August 31, 2005, the OEB decided that the scope of its review of these applications is appropriately dictated by Section 86 of the *Ontario Energy Board Act, 1998* and its objectives as stated. It also decided that reviews of the related transaction processes themselves are beyond its purview.

Recent Developments

The Energy Conservation Responsibility Act, 2005

In November 2005, the Provincial Government introduced Bill 21, *The Energy Conservation Responsibility Act, 2005*, the overall purpose of which is to encourage energy conservation and promote energy efficiency in its own affairs. If passed, it would enable regulations to designate certain goods, services and technologies for this purpose, requires public agencies to establish energy conservation plans and to consider energy efficiency in capital acquisitions, authorizes the Minister to enter into agreements, provides for compliance orders in the case of contravention of the Act and also for the designation of enforcement officers.

The Bill proposes changes to the *Electricity Act, 1998*, to provide for the implementation of the Government's smart metering initiatives, by enabling the establishment of the Smart Metering Entity ("SME"), specifying its roles and responsibilities and the obligations of electricity distributors respecting smart meter installations and also their provision of information to the SME. If passed, distributors will own, install, operate and maintain the meters and continue to bill their customers. Distributors are prohibited from conducting discretionary metering activities from the date of the Bill's introduction (November 3, 2005).

If the Bill is enacted in its present form, the OEB may be mandated via Cabinet directives, to implement smart metering initiatives through amendments to licence conditions, as well as through regulatory and accounting treatment of costs to ensure that distributors, retailers and others are not financially disadvantaged by the Government's smart metering initiative. Although there continues to be a high level of uncertainty surrounding the implementation details of the smart meters program, we anticipate that the resulting expenditures will be recoverable.

The OEB's Hearings on Generic C&DM and Distribution Issues

As a result of several issues having been identified both during the C&DM hearings and leading up to the review of distributors' rate applications, the OEB convened two further generic proceedings late in 2005.

A critical C&DM issue was whether the OEB may and should impose a higher level of spending on C&DM initiatives for 2006, as well as whether aspects of the framework for judging the success of distributors' C&DM programs could be changed. Hydro One Networks Inc. urged the OEB to maintain its original direction, not mandate higher C&DM spending and not change the regulatory framework respecting C&DM, given the implications for distributors' rate applications for 2006 which are already under review.

The OEB also requested submissions from distributors on the cost treatment for 2006 activities on smart metering and the potential need for variance or deferral accounts in a few other areas. Hydro One Networks Inc. requested as much flexibility on behalf of itself and other distributors as possible on these issues.

A decision on both of these proceedings is anticipated within the first quarter of 2006.

RISK FACTORS

We are controlled by the Province and may have conflicts of interest with the Province and related parties.

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence major business and corporate decisions, including, for example, financing programs and our dividend policy. We and the Province have entered into a shareholder's agreement which requires us to consult with the Province in connection with our business plans to ensure that these plans are consistent with the purposes of the *Electricity Act, 1998* and the objectives of the OEB under the *Ontario Energy Board Act, 1998*. These purposes and objectives, which are specifically set out in the *Electricity Act, 1998*, and the *Ontario Energy Board Act, 1998*, relate to the development of competitive electricity markets in Ontario and the protection of the interests of Ontario's electricity consumers. The shareholder's agreement also requires that we consult with the Province with respect to matters concerning our dividend policy and obtain approval from the Province in advance of any proposal to issue or transfer shares in our company or our subsidiaries, any major transaction, including the sale of assets, which would potentially have a material effect on the financial interest of the Province, or our ability to make payments to the Ontario Electricity Financial Corporation in lieu of taxes under the *Electricity Act, 1998*. Finally, the Province retains the power to regulate Ontario's electricity industry.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry, the regulation of environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in Hydro One and the determination of the amount of payments to be made by us to the Province by way of dividends or to the Ontario Electricity Financial Corporation in lieu of taxes.

Conflicts of interest may also arise as a result of the Province's 100% ownership of Ontario Power Generation Inc. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which would have an adverse impact on our business.

Regulatory Risk

On August 17, 2005, we filed a rate application seeking approval for a \$160 million increase in the 2006 revenue requirement of Hydro One Networks Inc.'s distribution business. As this is our first full cost of service rate submission since 1999 and as recent rate increases and commodity price increases have increased customer bills, we expect this submission to be closely examined by the OEB and intervenors. This could result in increased risk of disallowance by the OEB. For example, past or future expenditures could be disallowed or elements of the approved revenue requirement could be delayed. In addition, within the scope of this review, the OEB will review the recoverability of certain pension costs incurred within our distribution business and deferred in a regulatory deferral account. In accordance with a 2004 order from the OEB, we deferred the non-capital portion of our distribution-related pension costs incurred in 2004 and 2005 as a regulatory asset. These deferred expenditures amounted to \$76 million as at December 31, 2005, inclusive of interest. Should the OEB determine that some of these expenditures are not recoverable from customers, we will charge them to the results of operations when the decision is rendered, which will have an adverse effect on our business.

The OEB's December 9, 2004 decision allowing recovery of the majority of the regulatory asset amounts we applied for has significantly reduced the proportion of our total regulatory asset balance at risk for future disallowance. There may still be some residual risk of future OEB disallowance of unreviewed account balances. In the event that some of these amounts are disallowed by the OEB during our 2006 rate review, the appropriate amount will be reflected in results of operations in the period when the OEB decision occurs.

On October 26, 2005, the OEB initiated a proceeding to approve or fix revenue requirements for our transmission business for the years 2006, 2007 and 2008. For the period from January 1, 2006 until revised rates are implemented, the OEB intends to track net income in excess of the currently approved returns. Tracking options could include the use of a regulatory deferral account or an earnings-sharing mechanism. This results in a risk of having some of our transmission revenues (for the period from January 1, 2006 until new rates are implemented) recaptured if excess earnings occur. We have proposed an earnings-sharing mechanism that would result in any over earnings being returned to customers in the form of transmission system expansion projects that are critical to the economic and secure operation of the transmission system. Our proposal is consistent with practices recently utilized in other North American jurisdictions requiring significant system investments. A hearing on our proposal was held on November 23, 2005 and a decision is expected by the OEB in the first quarter of 2006. The initiation of a transmission proceeding could result in a decision by the OEB which could have a material adverse effect on our business.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset these impacts.

There is also a risk we could be required to incur unexpected capital expenditures to maintain or improve our transmission and distribution assets and to connect new third-party generation assets. We expect to be required to make material future capital investments in new technologies, such as smart meters. While we expect these expenditures to be fully recoverable, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment and charges to operations.

The OEB has recognized the need to compensate utilities for lost revenue resulting from a successful conservation and demand management program, but the approach, level and timing of any such compensation mechanism is yet to be determined.

The OEB's amendments to the Transmission System Code could lead to duplication and unnecessary stranding of Hydro One's transmission transformation assets.

The OEB's June 8, 2004 decision on the Transmission System Code enables load customers to transfer existing transformation load from Hydro One's facilities to their newly constructed facilities, provided that the transmitter is compensated on the basis of net book value for the asset and, where the customer is a distributor, the transaction passes a prudence review by the OEB. We have concerns that this approach will not protect our remaining customers from the resulting increase in rates. Our analysis indicates beneficial economics for customers to potentially off-load up to 13,000 MW, or 60% of Hydro One's current transformation load from our fully-loaded, and often substantially depreciated, transformer stations, to their own facilities. This could result in significant future revenue loss to our transmission business and there is currently no assurance that we would be adequately compensated for such lost revenue.

We could experience service disruptions and increased costs if we fail to maintain and improve our aging asset base.

Our installed asset base requires continual maintenance, improvement and expansion to provide reliable service and to accommodate customer needs and load growth within the Province. We acquired transmission and distribution assets from Ontario Hydro whose maintenance had been deferred in favour of allocating funds to other business units. As a consequence, reliability of transmission and distribution assets deteriorated. Moreover, Ontario's current generation situation has created significant dependence on the transmission networks to sustain the reliability of the Province's power system. To address these circumstances, we have been making significant expenditures to limit asset deterioration or improve their performance and to enhance our asset management and monitoring capabilities. We expect to continue to make significant capital and maintenance expenditures with respect to these assets for the next several years. Failure to carry out these programs to maintain and improve our asset base will have a material adverse effect on the reliability of the provincial grid and consequently to our company.

Our facilities could be affected by severe weather, other natural disasters or catastrophic events, and we have limited insurance coverage for losses resulting from these events.

Our facilities are exposed to the effects of severe weather conditions, natural disasters and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to withstand occurrences of this type, our

facilities may not do so in all circumstances. In addition, many of our facilities are located in remote areas, which makes access for repair of damage difficult.

We have no insurance for damages caused by severe weather, other natural disasters or catastrophic events to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations. In the event of a large uninsured loss to our transmission or distribution business, we might apply to the OEB for the recovery in our future rate orders of increased costs. The OEB might decide not to approve, in whole or in part, an application by us for recovery of these costs. Losses resulting from repair costs and lost revenues could be substantial and we could be subject to claims for damages caused by the failure to transmit or distribute electricity. As a result, any major damage to our facilities could result in lost revenues, repair costs and claims that could be substantial and that could have a material adverse effect on our net income.

The Hydro One transmission system has several interconnections with utilities in other provinces and the United States. These interconnections can import large amounts of power. The risk of major weather or catastrophic events impacting multiple interconnection facilities is significantly mitigated by the large number of interconnections and their diverse geographic locations. There are in total 26 interconnections with connections to Manitoba, Québec, New York, Michigan and Minnesota with a combined import capability of 3900 MW.

Our outsourcing arrangement with Inergi LP may not yield the anticipated reduction in operating costs.

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi LP, an affiliate of CapGemini Canada Inc. Under this agreement, Inergi LP provides us with, among other things, customer service operations and supply management, pay operations, information technology and finance and accounting services over a 10-year term for aggregate base fees during that period of approximately \$1 billion. These fees are subject to decreases based on benchmarking against industry standards and other adjustments. As part of this outsourcing arrangement, approximately 900 of our employees were transferred to Inergi LP on March 1, 2002. Although we believe that the outsourcing arrangement will yield cost savings over the term of the agreement, we may not, in fact, achieve all of the expected cost reductions. If the agreement with Inergi LP is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the functions involved, which could have a material adverse effect on our financial performance.

Our profitability and cash flow could decline if we fail to further improve our labour productivity.

The substantial majority of our employees are represented by either the Power Workers' Union (the "PWU") or the Society of Energy Professionals (the "Society"). Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost efficient manner. Although we believe that we have achieved improved flexibility in our collective agreements, we may not be able to further improve them. In an effort to achieve further flexibility in the collective agreement with the Society, the Company endured a 15-week strike in 2005. While improvements in flexibility and productivity were achieved, we may not be able to achieve further improvements in flexibility and productivity in the future. Our rate orders

incorporate revenue requirements that assume that we will achieve reduced labour costs. Accordingly, any inability on our part to continue to achieve increases in labour productivity and associated reduced costs could have a material adverse effect on our financial performance.

The substantial majority of our employees are represented by either the PWU or the Society . As a result, in the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers. We also face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. Existing collective agreements with the PWU and the Society will expire on March 31, 2008.

We may have a high number of retirements over the next few years and our success will be tied to our ability to hire and recruit staff to replace those leaving.

Our ability to implement our corporate strategy is dependent upon our success in attracting and retaining senior management and other staff and the ability of management and employees to work together as a cohesive team capable of operating in a dynamic, commercial environment. We must acquire and retain staff with the skills required to implement new processes and systems. Many of our employees possess experience and skills that will be highly sought after by other organizations active in the electricity sector and elsewhere. Skilled managers and other employees are also required to ensure that project management and control objectives are satisfied in connection with major corporate initiatives. We must also continue to advance our training programs and succession plans to ensure that our operational staffing needs are met in the future. The demographics of our workforce pose a significant challenge with approximately 25% of our employees eligible for retirement by 2008. In some parts of the organization, the risk is much higher. There can be no assurance that we will be able to attract and retain qualified personnel.

Our operations could expose us to substantial and currently undetermined environmental costs and liabilities.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply with environmental regulations could subject us to fines and other penalties. In addition, releases of hazardous or other substances on or from properties now owned, leased, occupied or used by us, or as a result of our operations, could lead to governmental orders requiring us to investigate, control and remediate the effects of these releases. The presence or release of hazardous or other substances could also lead to claims by third parties.

We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. It involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for Hydro One and adjacent private properties.

Future changes in environmental regulations may result in material changes to the expenditure estimates used to calculate the carrying values of our environmental liabilities and associated regulatory assets. In addition, any contamination on our properties could limit our ability to sell these assets in the future. Actual future environmental expenditures may vary materially from the

estimates used in the calculation of the environmental liability on our balance sheet. We do not have insurance coverage for this environmental expenditure.

In addition, obtaining governmental environmental approvals, permits or renewals of existing approvals and permits may require environmental assessment or result in the imposition of conditions, or both, which may be costly. The construction of new facilities requires environmental assessments and government approvals, which can result in delays and increase the cost of construction or operation of new facilities. In some cases, the imposition of conditions could adversely affect our planned costs to construct or operate a facility.

Scientists and public health experts in Canada, the United States and other countries have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, litigation could result, and we could be required to take mitigation measures at our facilities. The costs of litigation and mitigation measures could be material, particularly if we were required to relocate our existing transmission and distribution facilities. Public concern over the health risks associated with electric and magnetic fields could make it difficult for us to site and build new transmission and distribution facilities.

Our financial position could be adversely affected if we fail to arrange substantial, cost effective financing to repay maturing debt and to fund capital expenditures, dividends and other obligations.

We have substantial amounts of existing debt which mature between 2006 and 2009, including \$589 million maturing in 2006 and \$395 million maturing in 2007. We also plan to incur total capital expenditures of approximately \$755 million in 2006. We expect our base capital expenditures to be in the range of \$600 million annually over the next several years for the sustainment of the core system. Significant additional expenditures may be required for these projects and those that we may undertake to expand the transmission system consistent with the Integrated Power System Plan anticipated to be issued by the Ontario Power Authority in the summer of 2006 as well as conservation initiatives such as the deployment of smart meters. In addition, we plan to pay quarterly dividends on our outstanding common shares as well as dividends on any preferred shares in accordance with their terms. The declaration and payment of dividends on our common shares will be at the discretion of our Board of Directors and will also be dependent on our results of operations, financial condition, cash requirements and other relevant factors.

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our financial performance.

We may be required, in the future, to make substantial contributions to our pension plan, which could negatively affect our net income.

We have a defined benefit registered pension plan for the majority of our employees. Our contributions to the pension plan are based on periodic actuarial valuations.

Prior to January 1, 2004, our actuarial valuation did not result in a requirement to contribute to our pension plan. On September 22, 2004, we filed our most recent actuarial valuation as at December 31, 2003 with the Financial Services Commission of Ontario. This valuation covers the period January 1, 2004 to December 31, 2006 inclusive. Under the new valuation, we are obligated to make annual cash contributions to the pension plan of approximately \$80 million per year. The amount of the contributions that may be required after December 31, 2006 will depend on future investment returns, changes in benefits or actuarial assumptions.

On July 14, 2004, the OEB issued an order approving the establishment of a regulatory deferral account to record the expense portion of distribution-related pension contributions, as well as interest thereon. While the OEB decided that it was premature to confirm that these costs were prudently incurred, it did note that prudently incurred costs of this type are normally recoverable as part of a general rate adjustment application. In accordance with the OEB's order, we have deferred distribution pension expenditures which were incurred throughout 2004 and 2005 as a regulatory asset. We expect to continue to defer these costs until the OEB renders a decision on recoverability. Such a decision is anticipated in conjunction with the rate proceeding to set the 2006 revenue requirement for our distribution business. Should the OEB determine that some of these expenditures are not recoverable from customers, we will charge them to the results of operations in the period when the decision is rendered, which would have a negative impact on our Company.

Our profitability and cash flow could be negatively affected by potentially significant costs to complete the transfer to us of transmission, distribution and other assets located on Indian lands.

The transfer orders by which we acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). The transfer of title to these assets did not occur because authorizations originally granted by the federal Minister of Indian and Northern Affairs for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. These assets represent approximately 0.13 % of our total assets as at December 31, 2005 and consist primarily of approximately 82 kilometres of transmission lines and approximately 1,256 kilometres of distribution lines (of which 14 kilometres of lines are used solely for serving customers off the reserves). The Ontario Electricity Financial Corporation holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title to these assets to us.

We are seeking to obtain from the relevant Indian bands and bodies the consents necessary to complete the transfer of title to these assets. We cannot predict, however, the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents.

We anticipate having to pay more than the approximately \$850,000 per year that we currently are paying to these Indian bands and bodies and that is the allowed cost for this matter in our rate orders. If we cannot obtain consents from the Indian bands and bodies, the Ontario Electricity Financial Corporation will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such an event with respect to our transmission business, we may apply to the OEB for the recovery in our future rate orders of increased costs. The OEB could decide not to approve, in whole or in part, an application by us for recovery of these costs. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them.

The Province has passed legislation pursuant to which it has acquired our transmission corridors which could result in additional costs and may result in a reduction of our net income.

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our owned lands underlying our transmission system, which are referred to as “transmission corridors”. Revenue from current and future third party uses of the transmission corridors could be affected adversely by this acquisition. Although we have the statutory right to use the transmission corridors for the purposes of our transmission, distribution and telecommunications systems, we may be limited in our ability to expand our systems in the future. Other uses of the transmission corridors, whether by the Province or others, in conjunction with the operation of transmission, distribution or telecommunications systems may increase safety or environmental risks.

DIVIDENDS

Dividends on our common shares are declared at the discretion of our board of directors, and are recommended by our management based on our results of operations, financial condition, cash requirements and other relevant factors, such as industry practice and shareholder expectations.

Our company’s policy is to declare and pay cash dividends on our common shares on the basis of a calculation involving our regulated net income and non-regulated net income.

We declared and paid to the Province annual dividends on our outstanding 100,000 common shares totalling \$273 million in 2005 as compared with \$247 million in 2004 and \$226 million in 2003. We declared and paid to the Province a total annual cumulative dividend on our outstanding 12,920,000 series A preferred shares of approximately \$18 million in each of 2005, 2004 and 2003, which was calculated at a rate of \$1.375 per annum per share, as stipulated in our company’s Articles of Incorporation.

Dividends on our common shares are calculated based on net income. Any factor that adversely affects our company’s net income would likely be reflected in our dividend payments.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The authorized share capital of our company consists of an unlimited number of common shares (the voting shares of the company) and an unlimited number of preferred shares. As at December 31, 2005, 100,000 common shares and 12,920,000 series A preferred shares are issued and outstanding, all of which are owned directly by the Province.

All of our company's voting securities are held by the Province. Accordingly, our company is controlled by the Province.

The common shares are not redeemable or retractable. Holders of our common shares are entitled to one vote per share at meetings of the shareholders of the common shares and to receive dividends if, as, and when declared by the board of directors of our company. Holders of common shares are also entitled to participate, pro rata to their holding of common shares, in any distribution of the assets of our company upon its liquidation, dissolution or winding-up. The series A preferred shares, as set forth in our Articles of Incorporation, entitle our company to redeem all or any part of these shares subject to certain terms and conditions as set forth therein. These series A preferred shares are entitled to a dividend at a rate of \$1.375 per annum per share.

Our company has not issued any restricted securities.

CREDIT RATINGS

Our company's corporate credit ratings from approved rating organizations are as follows:

Rating Agency	Short-term Debt	Long-term Debt
Standard & Poor's Rating Services ("S&P")	A-1	A
Dominion Bond Rating Service Inc. ("DBRS")	R-1 (low)	A
Moody's Investors Services Inc. ("Moody's")	Prime-1	Aa3

The following information relating to credit ratings is based on information made available to the public by the rating agencies.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The rating agencies rate debt instruments by rating categories ranging from a high of "AAA" to a low of "D" ("C" in the case of Moody's). Debt instruments which are rated in the A category by S&P mean the obligor has a strong capacity to meet its financial commitments but are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. However, the obligor's capacity to meet its financial commitments and obligations is still strong. The minus modifier indicates the relative standing within the rating category. Debt instruments

which are rated in the A category by DBRS are considered to be of a satisfactory credit quality, with substantial protection of interest and principal. Debt instruments which are rated in the Aa category by Moody's are judged to be of high quality and are subject to very low credit risk. Moody's applies numerical modifiers to each generic rating classification from Aa to Caa. The modifier 3 indicates a ranking in the lower end of that generic rating category.

The ratings mentioned above are not a recommendation to purchase, sell or hold our company's debt securities and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant.

MARKET FOR SECURITIES

Our 7.15% Debentures due 2010, 7.35% Debentures due 2030, Series 1 Notes (6.40%) due 2011, Series 2 Notes (6.93%) due 2032, Series 3 Notes (5.77%) due 2012, Series 4 Notes (6.35%) due 2034, Series 5 Notes (6.59%) due 2043, Series 6 Notes (4.00%) due 2008, 4.150% Notes due April 21, 2006, 4.200% Notes due June 1, 2006, 4.300% Notes due November 10, 2006, 4.450% Notes due May 4, 2007, 4.550% Notes due August 10, 2007, Series 7 Notes (3.950%) due February 24, 2009, Series 8 4.100% Extendable Step-up Notes initially due May 15, 2007 and Series 9 Notes (5.36%) due 2036 are not listed on any exchange or similar market for securities.

Trading Price and Volume

The debt securities issued by our company are not listed on a recognized exchange or quoted on a recognized quotation and trade reporting system.

Prior Sales

Our company issued the following tranches of medium term notes in 2005:

Note	Par Value (M) (\$)	Sale Price (\$)	Gross Proceeds (\$)
3.95% due 2009	150	101.187	\$151,780,500
5.36% due 2036	350	99.865	\$349,527,500

DIRECTORS AND OFFICERS

Directors

The following table sets forth the name, municipality of residence and principal occupation of each of our directors, as of December 31, 2005.

Name and Municipality of Residence

Principal Occupation

Rita Burak ⁽²⁾
Toronto, Ontario
Canada
(Director since June 11, 2002 and
Chair since May 30, 2003)

Chair of the Board of Directors of Hydro One
Inc.

Sami Bébawi ⁽⁴⁾⁽⁵⁾
Outremont, Québec
Canada
(Director since October 8, 2004)

Executive Vice-President,
Member, Office of the President
SNC-Lavalin Group Inc.
President, Socodéc Inc.

Murray J. Elston ⁽¹⁾⁽⁴⁾
Manotick, Ontario
Canada
(Director since June 11, 2002)

President and C.E.O.,
Canadian Nuclear Association

Don MacKinnon ⁽⁴⁾⁽⁵⁾
Chatsworth, Ontario
Canada
(Director since June 11, 2002)

President,
Power Workers' Union

Eileen A. Mercier ⁽¹⁾⁽²⁾
Toronto, Ontario
Canada
(Director since August 15, 2002)

Corporate Director

Walter Murray ⁽¹⁾⁽³⁾
Bracebridge, Ontario
Canada
(Director since November 10, 2005)

Corporate Director

Kathleen O'Neill ⁽¹⁾⁽³⁾
Toronto, Ontario
Canada
(Director since July 27, 2005)

Corporate Director

Tom Parkinson
Oakville, Ontario
Canada
(Director since April 16, 2003)

President and Chief Executive Officer,
Hydro One Inc.

<u>Name and Municipality of Residence</u>	<u>Principal Occupation</u>
Hon. Bob Rae ⁽²⁾⁽³⁾ Toronto, Ontario Canada (Director since June 11, 2002)	Partner, Goodmans LLP
Douglas E. Speers ⁽¹⁾⁽⁵⁾ Coldwater, Ontario Canada (Director since November 10, 2005)	Chairman and Director, Emco Corporation
Kenneth D. Taylor ⁽⁴⁾⁽⁵⁾ New York, New York USA (Director since June 11, 2002)	Chair, Taylor and Ryan Inc.
Blake Wallace ⁽²⁾⁽³⁾⁽⁴⁾ Toronto, Ontario Canada (Director since November 22, 2002)	Vice President and Director, Murray & Company

- (1) Member of the Audit and Finance Committee
- (2) Member of the Corporate Governance Committee
- (3) Member of the Human Resources and Public Policy Committee
- (4) Member of the Regulatory and Environment Committee
- (5) Member of the Health and Safety Committee

Rita Burak was appointed Chair of Hydro One Inc. on May 30, 2003. She served as the Vice Chair of our Board of Directors from August 22, 2002 to May 30, 2003. She is also a Director of The Equitable Life Insurance Company of Canada and the President of a consulting partnership, The Network Executive Team, Management Consultants, Inc. and has held such posts since 2003 and 2001, respectively. Ms. Burak is the Vice Chair of the University of Guelph and a member of the University Health Network Board of Trustees. From 1995 to 2000, she served as Secretary of the Cabinet in Ontario and is a Member of the Order of Ontario. Ms. Burak has been a Director of our company since June 11, 2002.

Sami Bébawi is Executive Vice President of SNC-Lavalin Group and member of the Office of the President. SNC-Lavalin (TSX:SNC) is one of the leading groups of engineering and construction companies in the world. Mr. Bébawi has the corporate responsibility in project

management at SNC-Lavalin Group and is a adjunct professor at Concordia University, Montreal. He has several years of experience in designing and building thermal, hydro and nuclear power plants. Mr. Bébawi is a Member of the Ordre des ingénieurs du Québec and a past member of the Danish Engineers Association. He has been a Director of our company since October 8, 2004.

Murray J. Elston was appointed President and CEO of the Canadian Nuclear Association (“CNA”), effective January 5, 2004. The CNA is a non-profit organization that represents the nuclear industry in Canada and promotes the development and growth of nuclear technologies for peaceful purposes. He previously served as President of Canada’s Research-Based Pharmaceutical Companies, a national association representing over 60 research-based pharmaceutical companies, to which he was appointed in November 1998. From 1981 to 1994, he served as a Liberal MPP in the Ontario Legislature, where he held the positions of Minister of Health, Chairman of Management Board, Minister of Financial Institutions and Chairman of the Public Accounts Committee. Mr. Elston has been a Director of our company since June 11, 2002.

Don MacKinnon has been President of the Power Workers’ Union, an electricity industry workers union, since May 2000 and a lineman by trade since 1971. He was Vice-President of the Union for 11 years prior to being elected President. In 2000, Mr. MacKinnon was appointed by the Minister of Energy, Science and Technology to the Electricity Transition Committee. He was a member of the Board of Directors of the Electrical and Utilities Safety Association and the Retail Management Board of Ontario Hydro. In 2003, Mr. MacKinnon was appointed by the Minister of Energy to the government’s Electricity Conservation and Supply Task Force. In 2005, Mr. MacKinnon became a member of the Canadian Nuclear Association’s Board of Directors. Mr. MacKinnon has been a Director of our company since June 11, 2002.

Eileen A. Mercier formed her own management consulting firm, Finvoy Management Inc., specializing in financial strategy, restructuring and corporate governance issues, in 1995. Prior to that time, she was Senior Vice-President and Chief Financial Officer of Abitibi-Price Inc. As an active member of the Board of Directors of several business and not for profit institutions, Mrs. Mercier’s affiliations include: CGI Group Ltd., Teekay Shipping Corporation, ING Bank of Canada, ING Canada Inc., Winkpak Limited, Shermag Inc., The University Health Network, York University and the Ontario Teachers’ Pension Plan Board (the “OTPPB”). Mrs. Mercier is also Chair of the OTPPB’s Investment Committee. Mrs. Mercier has been a Director of our company since August 15, 2002.

Walter Murray is a former Vice-Chairman and member of the Executive Committee of RBC Capital Markets. Prior to his retirement from the Royal Bank of Canada in April 2005, his 38-year career with the bank included senior responsibility for relationship cover for a portfolio of major Canadian and international accounts, Corporate Banking activities across Canada, and several executive postings, including serving as Regional Executive for RBC’s Chicago based, Midwestern USA Corporate Banking operations. Since 2000, Mr. Murray has been a member of Ivernia Inc.’s Board of Directors and Chair of its Audit Committee. Mr. Murray has been a Director of our company since November 10, 2005.

Kathleen O’Neill is a Fellow of the Institute of Chartered Accountants and a member of the Board of Directors of MDS Inc. and the TSX Group Inc. Until 2005, Ms. O’Neill was a senior executive with the BMO Financial Group where her most recent position was Executive Vice-

President, Personal & Commercial Development, and Head of Small Business Banking, which she held from 2002 - 2004. Prior to joining the BMO Financial Group in 1994, she was a Tax Partner with PricewaterhouseCoopers from 1988 - 1994 where she provided clients with advice on corporate structuring and international tax issues, as well as audit issues. Ms. O'Neill's extensive community experience includes Chair of the St. Joseph's Health Centre's Board of Directors, Toronto (2001 - 2003), as well as Chair of the Centre's Audit & Finance Committee (1996 - 2001), and is currently on several non-profit boards. Ms. O'Neill has been a Director of our company since July 27, 2005.

Tom Parkinson was appointed the President and Chief Executive Officer of Hydro One Inc. on April 9, 2003, effective as of January 21, 2003, after serving as our President and Chief Operating Officer since July 2002. He joined Hydro One in 2001 as President and Chief Executive Officer of Hydro One Network Services Inc. Until 2005, Mr. Parkinson was a member of the Board of Directors of the IESO, representing the transmitter class of stakeholders. Mr. Parkinson is a member of the Board of Directors of the Canadian Electricity Association and became the organization's Chair in 2005. Prior to joining Hydro One, Mr. Parkinson was CEO and Managing Director of NorthPower in Australia from 1995 through 2001. Mr. Parkinson was CEO of Oxley Electricity & Water from 1994 to 1995, and a senior executive with Illawarra Electricity from 1981 to 1994. Mr. Parkinson has been a Director of our company since April 16, 2003.

Honourable Bob Rae served as Ontario's 21st Premier from 1990 to 1995. He was elected eight times to federal and provincial parliaments, and served as leader of the Ontario New Democratic Party from 1982 to 1996. He is currently a partner at the law firm of Goodmans LLP and is a member of the Board of Directors of public companies and non profit organizations including Tembec Inc., The Toronto Symphony Orchestra, Institute for Research on Public Policy, Canadian Unity Council, Husky Injection Molding Systems and Retrocom Investment Management Inc. Mr. Rae is the Chancellor of Wilfred Laurier University. He also has extensive experience as a mediator and arbitrator both in Canada and internationally. He is a member of Her Majesty's Privy Council for Canada and an Officer of the Order of Canada. Mr. Rae has been a Director of our company since June 11, 2002.

Douglas E. Speers is Chairman and Director of Emco Corporation, a leading Canadian distributor of building materials for the residential, commercial and industrial construction markets. Prior to his appointment as Chairman, Mr. Speers was Emco's President and CEO from 1997 - 2004. Between 1971 and 1988, he held several senior positions with Imperial Oil Ltd. in Canada and Exxon International in New York City. Mr. Speers is a Professional Engineer - Province of Ontario, and is currently the Chair of the Executive Board, Canadian Industry Program for Energy Conservation (a joint industry-Federal Government initiative); Chairman of the Services Board and member of the Advisory Board of the Richard Ivey School of Business. He is a member of the Boards of a number of privately held companies and has been a Director of our company since November 10, 2005.

Kenneth D. Taylor is Chair, Taylor and Ryan Inc., a public affairs consulting company, and is currently Chancellor of Victoria University at the University of Toronto to which he was appointed in May 1998. Mr. Taylor is on the Board of Directors of a number of companies in Canada and the United States. He is the former Canadian Ambassador to Iran and the former Canadian Consul General in New York. Mr. Taylor is the recipient of the United States

Congressional Gold Medal and is an Officer of the Order of Canada. Mr. Taylor has been a Director of our company since June 11, 2002.

Blake Wallace, Q.C. is currently Vice President and a Director of Murray & Company, a full-service financial intermediary specializing in commercial, industrial and residential real estate, corporate finance, advisory services (debt and equity), privatizations and public-private partnerships. He has also served as Vice President and General Counsel of the company since 1972. Mr. Wallace is a former Vice-Chair of TVOntario and has been a Director of our company since November 22, 2002.

Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

Officers

The following table sets forth the name, municipality of residence and position of each of our executive officers:

<u>Name and Municipality of Residence</u>	<u>Position with our Company</u>
Tom Parkinson Oakville, Ontario Canada	President and Chief Executive Officer
Beth Summers Oakville, Ontario Canada	Chief Financial Officer
Laura Formusa Toronto, Ontario Canada	General Counsel and Secretary
Myles D'Arcey Ancaster, Ontario Canada	Senior Vice President, Customer Operations
Tom Goldie Mississauga, Ontario Canada	Senior Vice President, Corporate Services

Tom Parkinson's biographical information is presented above under "Directors".

Beth Summers was appointed as Chief Financial Officer on May 7, 2004 after serving as Corporate Controller of Hydro One Networks Inc. Prior to joining our company in 2001, Ms. Summers served as Senior Manager, Assurance & Advisory Services with Ernst & Young LLP.

Laura Formusa was appointed the General Counsel and Secretary of Hydro One Inc. on January 2, 2003. She joined Ontario Hydro in 1980 and has held the positions of Assistant General Counsel and General Counsel and Secretary of Hydro One Networks Inc.

Tom Goldie was appointed as Senior Vice-President, Corporate Services of Hydro One Networks Inc. on September 16, 2002. He joined Ontario Hydro in 1977 and has held the position of Vice-President, Human Resources of Hydro One Inc.

Myles D'Arcey was appointed as Senior Vice President, Customer Operations of Hydro One Networks Inc. on May 1, 2005. Mr. D'Arcey is also President and Chief Executive Officer of Hydro One Remote Communities Inc. He joined Ontario Hydro in 1978 and has held the position of Vice President, Station Services of Hydro One Networks Inc.

The officers of our Company are appointed by our Board of Directors and hold office until their successors are appointed, subject to resignation, retirement or removal by our Board of Directors.

There is no family relationship between any director or officer and any other director or officer.

Indebtedness of Directors and Executive Officers

As of February 1, 2006 and since the beginning of the most recently completed financial year of Hydro One, no director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of Hydro One or any of its subsidiaries had any outstanding indebtedness to Hydro One or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Hydro One or any of its subsidiaries other than certain mortgage subsidy payments to Mr. Parkinson as described below.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationships with the Province and Other Parties

Overview

The Province of Ontario owns all of our outstanding shares. As a result, the Province has the power to control all governance decisions affecting us, including the composition of our Board of Directors. Accordingly, the Province exercises control over our policies, the acquisition or disposition of assets, the incurrence of further debt and the payment of dividends to holders of our common and preferred shares.

The OEB is the principal regulator of Ontario's electricity industry. The Province appoints the members of the OEB and fills any vacancies on the OEB. The OEB is obligated to implement approved directives of the Province concerning general policy and objectives to be pursued by

the OEB and other directives aimed at addressing existing or potential abuses of market power by industry participants. The IESO directs the operation of our transmission system. The board of directors of the IESO, other than its chief executive officer, is appointed by the Province in accordance with the regulations in effect from time to time under the *Electricity Act, 1998*.

Transfer Orders

The transfer orders pursuant to which we acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer any asset, right, liability or obligation where the transfer would constitute a breach of the terms of any such asset, right, liability or obligation or a breach of any law or order. The transfer orders also did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). The transfer of title to these assets did not occur because authorizations originally granted by the Canadian Minister of Indian and Northern Affairs for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases because the authorizations had either expired or had never been properly issued. Ontario Electricity Financial Corporation holds these assets.

We are obligated under the transfer orders to manage both the assets held in trust until we have obtained all consents necessary to complete the transfer of title to these assets to us and the assets otherwise retained by Ontario Electricity Financial Corporation that relate to our businesses. We have entered into an agreement with Ontario Electricity Financial Corporation under which we are obligated, in managing the assets, to take instructions from Ontario Electricity Financial Corporation if our actions could have a material adverse effect on it. Ontario Electricity Financial Corporation has retained the right to take control of and manage the assets, although it must notify and consult with us before doing so and must exercise its powers relating to the assets in a manner that will facilitate the operation of our businesses. The consent of Ontario Electricity Financial Corporation is also required prior to any disposition of these assets.

The Province also transferred officers, employees, assets, liabilities, rights and obligations of Ontario Hydro in a similar manner to its other successor corporations. These transfer orders include a dispute resolution mechanism to resolve any disagreement among the various transferees with respect to the transfer of specific assets, liabilities, rights or obligations.

The transfer orders do not contain any representations or warranties from the Province or Ontario Electricity Financial Corporation with respect to the transferred officers, employees, assets, liabilities, rights and obligations. Furthermore, under the *Electricity Act, 1998*, Ontario Electricity Financial Corporation was released from liability in respect of all assets and liabilities transferred by the transfer orders, except for liability under our indemnity from Ontario Electricity Financial Corporation as discussed below. By the terms of the transfer orders, each transferee indemnifies Ontario Electricity Financial Corporation with respect to any assets and liabilities not effectively transferred and is obligated to take all reasonable measures to complete the transfers where the transfers were not effective.

Indemnities

Ontario Electricity Financial Corporation indemnified us with respect to the failure of the transfer orders to transfer any asset, right or thing or any interest therein related to our business

to us and some of our subsidiaries, some adverse claims or interests of third parties or based on title deficiencies arising from the transfer orders, except for some claims and rights of the Crown, and claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgment, settlement or payment in connection with litigation initiated by some utilities commissions. The Province has unconditionally and irrevocably guaranteed to us and our subsidiaries the payment of all amounts owing by Ontario Electricity Financial Corporation under its indemnity.

The indemnity specifically excludes any matter for which we have agreed or are required to indemnify Ontario Electricity Financial Corporation pursuant to or in connection with any transfer order. It also excludes any claim related to any aboriginal title or rights or the absence of a permit, right-of-way, easement or similar right in respect of lands held for Indian bands under the *Indian Act* (Canada). It also excludes any payment made, or loss, expense or liability incurred by us as a result of the failure of a transfer order to transfer any asset of Ontario Hydro described in the provisions of the transfer order relating to ineffective transfers.

The indemnity does not cover the first \$10,000 in value of each claim and only applies to the amount by which the total of all claims exceeds \$10 million. We are obliged to pay Ontario Electricity Financial Corporation a fee for the indemnity of \$5 million per year until such time as the parties agree that the indemnity should be terminated. We anticipate that we will require the indemnity until all indemnifiable claims have been identified and finally determined by a non-appealable court order. The indemnity ceases to be available to any of our subsidiary corporations if we cease to control them unless the cessation of ownership results from the sale of the shares of a subsidiary in connection with the enforcement of security on such shares by an arm's-length creditor of Hydro One. The indemnity can be assigned under some conditions with the consent of the Minister of Finance.

The Province has also agreed to indemnify the directors of Hydro One for any liabilities reasonably incurred by them in respect of any civil, criminal or administrative action or proceeding to which they are made a party to the extent that these liabilities result from a claim or determination that their approval of the indemnity by Ontario Electricity Financial Corporation constituted a breach of their duty to exercise the care, diligence or skill that a reasonably prudent person would exercise in comparable circumstances.

We have indemnified Ontario Electricity Financial Corporation in respect of the damages, losses, obligations, liabilities, claims, encumbrances, penalties, interest, deficiencies, costs and expenses arising from matters relating to our business and any failure by us to comply with our obligations to Ontario Electricity Financial Corporation under agreements dated as of April 1, 1999. These obligations include obligations to employ the employees transferred to us under the transfer orders, make and remit employee source deductions, i.e., tax withholding amounts, and employer contributions, manage the real and personal properties which Ontario Electricity Financial Corporation continues to hold in trust or otherwise and take any necessary action to transfer all of these properties to us, to pay realty taxes and other costs, provide access to books and records and to assume other responsibilities in respect of the assets held by Ontario Electricity Financial Corporation in trust for us.

Indebtedness

Hydro One incurred debt, on behalf of Hydro One and some of our subsidiaries, in connection with the acquisition of substantially all of the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses. The aggregate principal amount of this debt outstanding as at December 31, 2002 was approximately \$2.5 billion and was held by Ontario Electricity Financial Corporation in the form of notes with varying interest rates and maturity dates from 2002 to 2007. On February 20, 2003, we issued approximately \$213,727,000 of additional notes to Ontario Electricity Financial Corporation pursuant to an agreement between us and Ontario Electricity Financial Corporation dated February 20, 2003 to evidence payment by us to Ontario Electricity Financial Corporation of an amount to reduce the rate of interest payable on certain of the then outstanding notes. On March 5, 2003, Ontario Electricity Financial Corporation sold approximately \$2.1 billion of these outstanding notes in a public offering in the Canadian debt capital markets. As a result of this transaction, our company no longer has any indebtedness to the Ontario Electricity Financial Corporation.

Transmission Corridors

On June 27, 2002, the Province passed the *Reliable Energy and Consumer Protection Act, 2002* that provided for, among other things, ownership of all transmission corridor and abutting lands to be transferred from us to the Province in exchange for a statutory right to use the lands for transmission and distribution purposes effective December 31, 2002. We also retained the obligation to incur certain ongoing expenditures related to our use of this land, including maintenance, property taxes and any future environmental remediation work that may be required by the Province. The OEB is authorized to restrict or discontinue any use of the transmission corridor lands that interferes with the transmission system.

Operational Matters

Hydro One receives its revenues, which are in part collected by the IESO from customers, in accordance with the rules established under the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended from time to time.

Hydro One and the IESO have entered into an operating agreement, which took effect in May 2002, setting out the specific responsibilities of both parties relating to the provision of transmission service. Hydro One also purchases power from the IESO administered spot market (which was administered by Ontario Power Generation Inc. prior to May 2002).

Hydro One has several service agreements with the other successor corporations to Ontario Hydro, primarily Ontario Power Generation Inc. These services include field and engineering, logistics, corporate, telecommunications and information technology services.

Payments in Lieu of Corporate Taxes

We and our subsidiaries are exempt from taxes under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) because we are wholly owned by the Province and each of our subsidiaries is, in turn, wholly owned (directly or indirectly) by us. However, pursuant to the

Electricity Act, 1998, we and each of our subsidiaries are required to pay amounts to Ontario Electricity Financial Corporation, which are referred to as payments in lieu of corporate taxes, in respect of each taxation year, generally equal to the amount of tax that we would be liable to pay under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) if we were not exempt from taxes thereunder.

Shareholder's Agreement and Dividend Policy

We have entered into a shareholder's agreement with the Province relating to our corporate governance. Under this agreement, we must provide the Province with the financial and non-financial information necessary to allow the Province to periodically inform Ontario's legislature regarding our ongoing performance. This information includes all significant or contentious matters, progress reports concerning compliance with market power mitigation measures, information in respect of all matters requiring shareholder approval and all financial reports. Additionally, the shareholder's agreement requires that we consult with the Province with respect to matters concerning our dividend policy and obtain approval from the Province in advance of any proposal to issue or transfer shares in Hydro One or its subsidiaries, any major transaction, including the sale of assets, which would potentially have a material effect on the financial interest of the Province or our ability to make payments to Ontario Electricity Financial Corporation or payments in lieu of taxes under the *Electricity Act, 1998*.

TRANSFER AGENTS AND REGISTRARS

The trustee and registrar for our company's debt securities is Computershare Trust Company of Canada, Corporate Trust, located in Toronto, Ontario.

The U.S. trustee and registrar for our company's debt securities is Bank of Nova Scotia Trust Company of New York located in New York, New York.

MATERIAL CONTRACTS

Except for the following, since January 1, 2002, our company did not enter into any material contracts, other than contracts in the ordinary course of business:

- (a)
 - (i) a third supplemental trust indenture dated as of January 31, 2003 relating to the issuance of Series 4 Notes in the aggregate principal amount of \$1,000,000,000, of which \$200,000,000 was drawn down on January 31, 2003, \$120,000,000 was drawn down on June 25, 2004 and \$65,000,000 was drawn down on August 24, 2004, pursuant to the Trust Indenture dated as of June 4, 2001 (the "Trust Indenture");
 - (ii) a fourth supplemental trust indenture dated as of April 22, 2003 relating to the issuance of Series 5 Notes in the aggregate principal amount of \$1,000,000,000, of which \$250,000,000 was drawn down on April 22, 2003 and \$65,000,000 was drawn down on August 20, 2004, pursuant to the Trust Indenture;

- (iii) a fifth supplemental trust indenture dated as of June 23, 2003 relating to the issuance of Series 6 Notes in the aggregate principal amount of \$1,000,000,000, of which \$500,000,000 was drawn on June 23, 2003, pursuant to the Trust Indenture;
- (iv) a sixth supplemental trust indenture dated as of February 24, 2004 relating to the issuance of Series 7 Notes in the aggregate principal amount of \$1,000,000,000, of which \$250,000,000 was drawn down on February 24, 2004, pursuant to the Trust Indenture;
- (v) a seventh supplemental indenture dated as of November 15, 2004 relating to the issuance of Series 8 Notes in the aggregate principal amount of \$1,000,000,000, of which \$40,000,000 was drawn down on November 15, 2004, pursuant to the Trust Indenture; and
- (vi) an eighth supplemental indenture dated as of May 19, 2005 relating to the issuance of Series 9 Notes in the aggregate principal amount of \$1,000,000,000 of which \$350,000,000 was drawn down on May 19, 2005, pursuant to the Trust Indenture.

Each of these supplemental trust indentures supplement the terms of the Trust Indenture which contains customary covenants and representations by our company for the public issuance of debt securities in the Canadian market.

- (b) a Dealer Agreement dated June 24, 2005 between the company and BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. (collectively, the “Dealers”) relating to the public offering of unsecured medium term notes of Hydro One in a maximum aggregate principal amount of up to \$2,500,000,000. The Dealer Agreement provides for the appointment of the Dealers as non-exclusive agents of Hydro One to solicit, from time to time, offers to purchase the medium term notes in Canada and, in certain circumstances, the United States.

Copies of these documents are available on www.sedar.com.

INTERESTS OF EXPERTS

Ernst & Young LLP provides the following services to our company:

- (a) quarterly review of our company’s consolidated financial statements.
- (b) annual audit of our company’s consolidated financial statements.
- (c) annual audit of Hydro One Networks Inc.’s distribution business, Hydro One Remote Communities Inc.’s and Hydro One Brampton Networks Inc.’s financial statements.

- (d) annual audit of our company's pension fund.

Ernst & Young LLP is independent in Canada in accordance with its rules of professional conduct.

Mercer Human Resource Consulting LLC provides the following services to our company:

- (a) annual accounting actuarial valuation (valuation report prepared).
- (b) tri-annual funding actuarial valuation (valuation report prepared in 2004).
- (c) annual accounting actuarial valuation for supplementary pension plan for purposes of letters of credit (valuation report prepared).

ADDITIONAL INFORMATION

Additional Information about Hydro One is available on SEDAR (System for Electronic Document Analysis and Retrieval) at www.sedar.com

As our sole shareholder is the Province, we are not required to prepare an information circular. Additional financial information is contained in our audited comparative consolidated financial statements, together with the auditors' report thereon, and our Management's Discussion and Analysis for our most recently completed fiscal year, each of which may be found on SEDAR at www.sedar.com

STATEMENT OF EXECUTIVE COMPENSATION

Executive Compensation

The following table sets forth the annual compensation for the years ended December 31, 2003 to 2005 for each individual who served or acted as Chief Executive Officer or as a Chief Financial Officer during the most recently completed financial year, and for each of the three most highly compensated executive officers, other than the Chief Executive Officer and the Chief Financial Officer, at the end of the most recently completed financial year ("Named Executive Officers"). The information provided in the Summary Compensation Table differs from the information published under the *Public Sector Salary Disclosure Act* (Ontario) for the years ended December 31, 2003 to 2005. The differences are due to the timing of payment of incentive awards. Salary disclosures under the *Public Sector Salary Disclosure Act* are limited to amounts listed on T4 forms for each year. Information in the summary compensation table is based on the year the incentive was earned. The incentive is generally earned in one year and paid early in the following year.

Summary Compensation Table

Annual Compensation

	<u>Year</u>	<u>Salary</u>	<u>Bonus⁽¹⁾</u>	<u>Other Annual Compensation</u>	<u>All Other Compensation</u>	<u>LTIP Payouts</u>
Tom Parkinson	2005	\$780,000	\$702,000	\$129,630 ⁽³⁾		
President and Chief	2004	\$750,000	\$600,000	\$125,923 ⁽⁴⁾		
Executive Officer ⁽²⁾	2003	\$643,659	\$325,000	\$122,835 ⁽⁵⁾		
Beth Summers	2005	\$280,000	\$140,000	(6)		\$9,466 ⁽⁷⁾
Chief Financial Officer	2004	\$233,750	\$125,000	(6)		\$9,466 ⁽⁸⁾
	2003	\$182,989	\$55,500	(6)		
Myles D'Arcey	2005	\$285,000	\$142,500	(6)		\$21,793 ⁽⁷⁾
Senior Vice President,	2004	\$220,000	\$66,000	(6)		\$21,793 ⁽⁸⁾
Customer Operations	2003	\$200,000	\$50,000	(6)		\$10,717 ⁽⁹⁾
Laura Formusa	2005	\$280,000	\$140,000	(6)		\$29,481 ⁽⁷⁾
General Counsel and	2004	\$257,352	\$135,000	(6)		\$29,481 ⁽⁸⁾
Secretary	2003	\$246,167	\$125,000	(6)		\$14,926 ⁽⁹⁾
Tom Goldie	2005	\$280,000	\$140,000	(6)		\$51,987 ⁽⁷⁾
Senior Vice President,	2004	\$268,233	\$135,000	(6)		\$51,987 ⁽⁸⁾
Corporate Services	2003	\$259,400	\$104,000	(6)		\$21,528 ⁽⁹⁾

(1) This represents incentives paid under our short term incentive plan.

(2) Mr. Parkinson was appointed President and Chief Operating Officer of Hydro One on July 19, 2002 and acted in the capacity of Chief Executive Officer, along with Mr. Glen Wright, until Mr. Parkinson's appointment as President and Chief Executive Officer on April 9, 2003, effective as of January 21, 2003.

(3) This amount includes an executive allowance of \$40,000 and payment of \$40,478 under the flexible benefits program.

(4) This amount includes an executive allowance of \$40,000 and payment of \$41,544 under the flexible benefits program.

(5) This amount includes payment of \$34,368 under the flexible benefits program.

- (6) Each of Mr. Goldie, Ms. Formusa, Ms. Summers and Mr. D'Arcey is entitled to perquisites and other benefits in an amount that is less than \$50,000 and 10 per cent of the total of his or her annual salary and bonus.
- (7) This amount represents the aggregate of: (i) payment of the third and final instalment relating to the first performance period under our long term incentive plan, which was discontinued effective December 31, 2002, and (ii) payment of the second and final instalment of the second performance period thereunder for each of Mr. Goldie, Ms. Formusa, Ms. Summers and Mr. D'Arcey.
- (8) This amount represents the aggregate of: (i) payment of the second instalment relating to the first performance period under our long term incentive plan, which was discontinued effective December 31, 2002, and (ii) payment of the first instalment of the second performance period thereunder for each of Mr. Goldie, Ms. Formusa, Ms. Summers and Mr. D'Arcey.
- (9) This amount represents payment of the first instalment relating to the first performance period under our long-term incentive plan, which was discontinued effective December 31, 2002.

Hydro One has established a short-term incentive plan ("Short-Term Incentive Plan") for our executive and managerial employees, as well as separate plans for staff represented by the Power Workers' Union and the Society of Energy Professionals. However, through the collective bargaining process, the plan for Society of Energy Professional members was eliminated effective January 1, 2003, and the plan for members of the Power Workers' Union was eliminated on April 1, 2005.

The Human Resources and Public Policy Committee of our Board of Directors made a number of changes in management compensation during 2002 with respect to base salary, short-term incentive and long term incentive. With respect to long term incentive, our Board of Directors, on the advice of the Committee, decided to discontinue our long-term incentive plan effective December 31, 2002. Any credits which had been earned by employees up until that date have been paid, as we met our financial targets for the performance periods in question. This plan provided for executive and managerial employees to receive notional incentive units in proportion to their base salaries. These units appreciated in value based on achievement of a performance goal based on cumulative net income over three year performance periods. This plan provided that awards would vest and be paid over a three-year period, provided the employee remained employed by Hydro One, unless otherwise agreed to in individual employment contracts, and provided further that the cumulative three-year net income goal was achieved. There were two performance periods introduced before the plan was discontinued. The first performance period ran from January 1, 2000 to December 31, 2002 and the second performance period ran from January 1, 2001 to December 31, 2003. 100% of the awards were to be paid out for the first performance period and two-thirds of the awards were to be paid out for the second performance period, provided that the employee remained employed by Hydro One. All payments have now been made under the plan. 229 managerial employees received payouts for the third and final instalment of the first performance period and 254 managerial employees received payouts for the second and final instalment of the second performance period. These instalments were paid in 2005.

Benefits payable under Hydro One's registered pension plan are restricted by the *Income Tax Act* (Canada). This limit on benefits affects members whose average annual earnings exceed approximately \$119,000 in 2006. Participants whose pensions would otherwise be restricted by

the *Income Tax Act* (Canada) participate in an unregistered supplementary pension plan that provides benefits equal to the difference between the *Income Tax Act* (Canada) maximum pension benefits and the benefits determined in accordance with the formula set out in Hydro One's registered pension plan. The supplementary pension plan is unfunded and the additional retirement income is paid from general revenues. The supplementary pension plan is secured by a letter of credit.

The following table reflects an estimate of total annual lifetime benefits payable under the Hydro One registered pension plan and the unregistered supplementary pension plan. The table as set out below assumes a normal retirement age of 65, and assumes that the maximum pensionable earnings established under the Canada Pension Plan at retirement is equal to the maximum for 2005. Retirement at an earlier age may cause benefits to be subject to an early retirement discount.

Pension Plan Table

<u>Highest average earnings</u>	<u>15 years of Service</u>	<u>20 years of Service</u>	<u>25 years of Service</u>	<u>30 years of Service</u>	<u>35 years of Service</u>
\$200,000	\$56,053	\$74,738	\$93,422	\$112,106	\$130,791
300,000	86,053	114,738	143,422	172,106	200,791
400,000	116,053	154,738	193,422	232,106	270,791
500,000	146,053	194,738	243,422	292,106	340,791
600,000	176,053	234,738	293,422	352,106	410,791
800,000	236,053	314,738	393,422	472,106	550,791
1,000,000	296,053	394,738	493,422	592,106	690,791
1,200,000	356,053	474,738	593,422	712,106	830,791
1,400,000	416,053	554,738	693,422	832,106	970,791
1,600,000	476,053	634,738	793,422	952,106	1,110,791

For each year of credited service under the Hydro One Pension Plan (consisting of the Hydro One registered pension plan and the supplementary pension plan), to a maximum of 35 years, the benefit provided for each of the officers who participate in the plan is equal to 2% of the member's average base annual earnings during the 36 consecutive months (60 consecutive months for management employees hired on or after January 1, 2004) when his or her base earnings were highest, reduced by 0.625% of the member's average base annual earnings up to the year's maximum pensionable earnings during the 60 consecutive months when his or her base earnings were highest. Base annual earnings are comprised of the member's salary and 50% of his or her short term incentive. Unless altered by contractual agreement, the Hydro One Pension Plan provides for early retirement with an unreduced pension at the earlier of age 65 and the attainment of years of age plus continuous employment totalling 82 or more (85 for management employees hired on or after January 1, 2004). A plan member who is not eligible for an unreduced pension can retire with a reduced pension any time after attaining age 55. Bridge benefits are provided to all plan members except management employees hired on or

after January 1, 2004. Pension increases of 100% of the increase in the Ontario consumer price index (75% for management employees hired on or after January 1, 2004) will be given on January 1 of each year to pensioners, beneficiaries and terminated employees with deferred pensions. The normal form of pension for a member who does not have a spouse at retirement is a pension payable for life and guaranteed for five years. The normal form of pension for a member who has a spouse at retirement is a pension payable for the life of the member, and continuing after the member's death to his or her spouse at the rate of 66 2/3% of the amount the member was receiving.

Each of the Named Executive Officers participate in the Hydro One Pension Plan. The projected credited years of service that each will have is as follows: Mr. Parkinson – 34.33 years at age 60; Mr. Goldie – 35 years at age 65; Ms. Formosa – 35 years at age 65; Ms. Summers - 33.83 years at age 65; and Mr. D'Arcey - 35 years at age 65.

Each of Mr. Parkinson, Mr. Goldie, Ms. Formosa and Ms. Summers has entered into an employment agreement with Hydro One. Mr. Parkinson is entitled under his employment agreement to the salary, benefits and pension entitlement described above. The term of Mr. Parkinson's employment ends on January 31, 2010, unless extended by mutual agreement. Pursuant to the agreement, Mr. Parkinson's base salary increased by 4% in 2005 and is to increase by 3.85% in 2006 and 4.9% in 2007 and thereafter is to be reviewed annually by the Human Resources and Public Policy Committee and approved by our Board of Directors. If Mr. Parkinson's employment is terminated by Hydro One without cause, Mr. Parkinson is entitled to receive an amount equal to his base salary and executive allowance as at the date of termination either in a lump sum payment or in equal monthly instalments for a period of 24 months, and to receive, either in a lump sum payment or over the same 24-month period, full benefits, a bonus of not less than the greater of the average of the three previous bonus payments or 25% of his base salary, the continuation of mortgage subsidy payments (discussed below) up to a maximum of \$125,000 and reimbursement of certain relocation costs. Mr. Parkinson will continue to earn credited service under the Hydro One Pension Plan during such period (discussed below). Mr. Parkinson's employment agreement provides that termination without cause includes if Hydro One and Mr. Parkinson are not able to mutually agree to extend the term of his employment beyond January 31, 2010. These payments and contributions will also generally be payable to or for the benefit of Mr. Parkinson's estate if his death occurs during the term of his employment agreement or within 24 months from the date of any termination without cause. To recognize Mr. Parkinson's relocation to Canada, Hydro One has agreed, during the term of his employment agreement, to subsidize the monthly interest payable on the mortgage for Mr. Parkinson's home up to an aggregate amount of \$125,000.

Mr. Parkinson's employment agreement also provides for a supplemental retirement benefit plan for him, which will include pension and other benefits on the same basis as Hydro One's Pension Plan with certain enhancements. This supplemental plan provides for an unreduced early retirement pension on termination of employment at or after age 60. All such benefits paid to Mr. Parkinson under the supplemental plan will be reduced by the benefit payments made to him under Hydro One's Pension Plan when such payments are actually made. All credited service under the Hydro One Pension Plan will also be recognized as credited service under the supplemental plan and, for each year of his employment, Hydro One will credit the supplemental plan, for pension accrual and benefits eligibility purposes, with an additional one-half year of service. In addition, if Mr. Parkinson remains employed as President and Chief Executive

Officer until January 31, 2010, is terminated without cause or dies, Hydro One will credit the supplemental plan, for pension accrual and benefits eligibility purposes, an additional one-half year of service for each year of credited service. Further, upon Mr. Parkinson's death, resignation, retirement or termination, with or without cause, in calculating Mr. Parkinson's benefits under the supplemental plan, the base earnings used in his supplemental pension payment calculations shall be deemed to be increased by \$5,560 per month for the 36 consecutive months when his base earnings were highest.

Each of Mr. Goldie, Ms. Formusa and Ms. Summers is entitled under their respective employment agreements to the salary, benefits and pension entitlement under Hydro One's Pension Plan, as described above. If the employment of Mr. Goldie, Ms. Formusa or Ms. Summers is terminated by Hydro One without cause, each of Mr. Goldie, Ms. Formusa and Ms. Summers is entitled to receive an amount equal to his or her base salary at the date of termination in equal monthly instalments for a period of 24 months, and to receive benefits over the same period. Each of Mr. Goldie, Ms. Formusa and Ms. Summers will continue to earn credited service under the Hydro One Pension Plan during such 24-month period.

REPORT ON EXECUTIVE COMPENSATION

Responsibilities of Human Resources and Public Policy Committee

The mandate of the Human Resources & Public Policy Committee (the "Committee") includes reviewing the performance and remuneration of our senior executives, including recommending to the Board of Directors the remuneration of the President. In addition, the Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, and providing advice to the Board of Directors on public affairs issues that have a significant impact on our company. The Committee is comprised of the following directors: Hon. Bob Rae (Chair), Mr. Walter Murray, Ms. Kathleen O'Neill and Mr. Blake Wallace. The Hon. Bob Rae was appointed Chair of the Committee in 2004.

General

The compensation of Hydro One's executive officers, including those named in the Summary Compensation Table (the "Named Executive Officers"), is determined by our Board of Directors upon recommendation made by the Committee.

Hydro One's executive compensation program is designed to establish pay levels based on performance and be competitive with Canadian utility and energy companies, both publicly and privately owned. The design of the program facilitates the attraction, motivation and retention of executives, critical for Hydro One's current and long-term success.

The level of responsibility and the relative importance of all positions in Hydro One are evaluated to establish appropriate bases for internal and external comparison. To provide maximum objectivity, the evaluation of each executive officer position is determined by the Committee based on the advice of independent compensation consultants.

Compensation for executive officers consists of a base salary and an opportunity for an annual short-term incentive, all of which are overseen by the Committee. This assessment is based on a number of quantitative and qualitative factors which include contributions to key corporate strategies and financial results.

Base Salary

The Committee establishes salary ranges for the positions held by executive officers following a review of market data from peer group, industry and national surveys provided by independent consultants. In 2002, the Committee revised the compensation policy in relation to base salary. The peer group used by Hydro One for this purpose consists of Canadian utility and energy companies, both publicly and privately owned. Hydro One's policy for base salaries for executive officers is the 75th percentile of the target market. The actual level of base salary, within the approved range for each executive officer, including the Named Executive Officers, is determined on the basis of job function and the individual's performance and experience.

Short Term Incentive

Hydro One's Short-Term Incentive Plan provides an opportunity for participants, including the Named Executive Officers, to earn an annual cash incentive payment based on the achievement of performance targets set by the Board. Performance is measured by comparing actual results against targets established at the beginning of the year.

Potential awards are expressed as a percentage of base salary. For the Named Executive Officers, potential awards range between 0% and 50% of base salary (between 0% and 80% of base salary for the President and Chief Executive Officer) when target performance criteria are met and subject to the discretion of the Committee. The Board of Directors, in its discretion, may provide an award over the maximum for the President and Chief Executive Officer.

Long Term Incentive

The long term incentive plan is described above. The plan was discontinued effective December 31, 2002 and the final payouts under the plan were made in 2005.

President and Chief Executive Officer Compensation

The pay-for-performance philosophy of Hydro One's executive compensation program applies equally to the President and Chief Executive Officer. The compensation of the President and Chief Executive Officer is recommended by the Committee and approved by the Board after careful assessment of personal contribution to the performance of Hydro One. This assessment is based on a number of quantitative and qualitative factors which include financial results, strategic planning and initiatives, personal leadership and business acumen.

Compensation of Directors

The by-laws of Hydro One provide that directors may receive reasonable remuneration for their services, commensurate with their duties, together with reimbursement for all reasonable

expenses incurred in fulfilment of their duties, including travelling expenses. The amount of such remuneration is determined by the Board of Directors from time to time. The following remuneration is currently paid to directors:

Retainer for directors	\$25,000 per annum
Retainer for Committee Chairs	\$3,000 per annum
Participation in Board and Committee Meetings	\$900 per meeting

The fees are reviewed periodically. The President and Chief Executive Officer is not entitled to these fees.

Directors' fees, less statutory deductions, are paid quarterly by direct deposit or cheque as requested.

Rita Burak was appointed as Chair of our Board of Directors on May 30, 2003. Ms. Burak receives annual remuneration of \$150,000 per annum and does not receive any additional fees for serving as a director.

The foregoing report has been made by the members of the Human Resources and Public Policy Committee:

Hon. Bob Rae, Chair

Mr. Walter Murray

Ms. Kathleen O'Neill

Mr. Blake Wallace

APPOINTMENT OF AUDITOR

The auditor of our company is Ernst & Young LLP, who was first appointed as auditor on January 18, 1999.

AUDIT AND FINANCE COMMITTEE INFORMATION

The Audit and Finance Committee's Charter

Our Audit and Finance Committee's mandate, effective February 15, 2006, is attached hereto as Appendix "A", which Appendix is hereby incorporated by reference.

Composition of the Audit and Finance Committee

The members of our Audit and Finance Committee are Eileen A. Mercier, Murray J. Elston, Kathleen O'Neill, Walter Murray and Douglas E. Speers.

All members are independent and financially literate as such terms are defined under applicable Canadian securities legislation.

Relevant Education and Experience

In addition to each member's general business experience, the education and experience of each Audit and Finance Committee member that is relevant to the performance of his or her responsibilities as an Audit and Finance Committee member is described below.

Mrs. Mercier holds an MBA from York University. Mrs. Mercier formed her own management consulting firm, Finvoy Management Inc., specializing in financial strategy, restructuring and corporate governance issues, in 1995. From 1990 to 1995, Mrs. Mercier served as the Chief Financial Officer of Abitibi-Price Inc. In addition, Ms. Mercier is a Fellow of the Institute of Canadian Bankers. Since 1994, Mrs. Mercier has served on the audit committees of several boards of directors and is also Chair of the Ontario Teachers' Pension Plan Board's Investment Committee.

Mr. Elston has held various senior positions in the Government of Ontario including Chairman of the Management Board, Chairman of the Public Accounts Committee and Minister of Financial Institutions which involved a regulatory function with respect to financial institutions. Mr. Elston has also served in officer positions of several non-profit companies.

Ms. O'Neill is a Fellow of the Institute of Chartered Accountants. Ms. O'Neill has held various positions with BMO Financial Group and was a Tax Partner with PricewaterhouseCoopers where she provided advice on corporate structuring and international tax issues, as well as audit issues. Ms O'Neill has served on the audit committees of several boards of directors and was the Chair of the St. Joseph's Health Centre's Audit & Finance Committee.

Mr. Murray is the former Vice-Chairman and member of the Executive Committee of RBC Capital Markets. That role included senior responsibility for relationship cover for a portfolio of major Canadian and international accounts. Since 2000, Mr. Murray has been a director of Ivernia Inc.'s Board of Directors and Chair of its Audit Committee.

Mr. Speers holds an MBA from the Richard Ivey School of Business at the University of Western Ontario. He is currently Chairman and Director of Emco Corporation and has held several senior positions with Imperial Oil Ltd. in Canada and Exxon International. He is a member of the Boards of a number of privately held companies.

Audit and Finance Committee Oversight

There have been no recommendations of our Audit and Finance Committee to nominate or compensate an external auditor which have not been adopted by our board of directors.

Pre-Approval Policies and Procedures

In accordance with the provisions of its mandate, the Audit and Finance Committee ratifies all non-audit services, as pre-approved by the Committee Chair, to be provided to the Corporation by its external auditor.

External Auditor Service Fees

(a) *Audit Fees*

The audit fees billed by Ernst & Young LLP for fiscal 2004 were \$619,200. The audit fees billed by Ernst & Young LLP for fiscal 2005 were \$650,400.

(b) *Audit-Related Fees*

The total audit-related fees billed by Ernst & Young LLP for fiscal 2004 were \$86,000. The nature of the services rendered were: accounting and internal control consultations, audit of the Hydro One Pension Plan, French translations and executive expense review.

The audit-related fees billed by Ernst & Young LLP for fiscal 2005 were \$94,200. The nature of the services rendered were: accounting and internal control consultations, audit of the Hydro One Pension Plan, French translation and executive expense review.

(c) *Tax Fees*

The tax fees billed by Ernst & Young LLP for fiscal 2004 were \$25,075. The nature of the services rendered were: scientific research and development review and claim and general tax advice.

The tax fees billed by Ernst & Young LLP for fiscal 2005 were \$1,200. The nature of the service rendered was: general tax advice.

(d) *All Other Fees*

There are no other fees billed by Ernst & Young LLP which are applicable for fiscal 2004.

There are no other fees billed by Ernst & Young LLP which are applicable for fiscal 2005.

CORPORATE GOVERNANCE DISCLOSURE

Board of Directors

The Board has undertaken an independence assessment and determined that all of Hydro One's directors are "independent" within the meaning of the rules adopted by the Canadian Securities Administrators (the "CSA"), with the exception of Mr. Tom Parkinson, who is the President and Chief Executive Officer of the Company.

The Board has separated the roles of Chair and Chief Executive Officer. Ms. Rita Burak was appointed Chair of the Board on May 30, 2003 and is an independent director. The prime responsibility of the Chair of the Board of Directors is to provide leadership to the Board and to enhance Board effectiveness. The Chair, as the presiding member of the Board, also ensures that

the relationships between the Board, management, the shareholder and other stakeholders are effective, efficient and further the best interests of the Company.

Independent directors hold regularly scheduled meetings at which non-independent directors and members of management are not in attendance. During 2005, 6 such sessions without management were held. As well, the Audit & Finance Committee regularly holds such sessions with the external auditors and with the internal auditor. The Chair of the Audit and Finance Committee meets regularly with the internal auditor. These sessions encourage open and candid discussion among the independent directors.

Summary of Attendance of Directors:

The following table summarises the attendance of individual directors at meetings of the Board of Directors held for the 12-month period ending December 31, 2005.

Director	Board Meetings Attended
Rita Burak	12 of 12
Geoff Beattie ¹	8 of 10
Sami Bébawi	9 of 12
Murray J. Elston	12 of 12
Dr. Murray Frum ²	6 of 10
Don MacKinnon ³	9 of 9
Eileen A. Mercier	11 of 12
Walter Murray ⁴	1 of 1
Kathleen O'Neill ⁵	5 of 5
Tom Parkinson ⁶	11 of 11
Hon. Bob Rae	8 of 12
Kenneth D. Taylor	11 of 12
Douglas E. Speers ⁷	1 of 1
Blake Wallace	10 of 12
Adam Zimmerman ⁸	5 of 6

(1) Geoff Beattie was a member of the Board until November 10, 2005.

(2) Dr. Murray Frum was a member of the Board until September 29, 2005.

(3) Mr. MacKinnon was not in attendance at three Board Meetings because these meetings solely addressed labour relations matters and, as president of the Power Workers' Union, there was a conflict of interest.

(4) Walter Murray was elected to the Board on November 10, 2005.

(5) Kathleen O'Neill was elected to the Board on July 27, 2005.

- (6) Mr. Parkinson did not attend one Board Meeting as this meeting was scheduled for independent directors only.
- (7) Douglas E. Speers was elected to the Board on November 10, 2005.
- (8) Adam Zimmerman was a member of the Board until July 18, 2005.

Directors' Board Memberships in Other Reporting Issuers:

Director	Reporting Issuer
Geoff Beattie	Royal Bank of Canada, Tm Bioscience Corp., The Thomson Corporation
Eileen A. Mercier	CGI Group Inc., ING Canada Inc., Shermag Inc., Teekay Shipping Corporation, Winkpak Ltd.
Walter Murray	Ivernia Inc.
Kathleen O'Neill	MDS Inc., TSX Group Inc.
Hon. Bob Rae	Husky Injection Molding Systems Ltd., Tembec Inc.
Douglas E. Speers	Emco Ltd.
Kenneth D. Taylor	Desert Sun Mining Corp., Devine Entertainment Corp.

Board Mandate

The Board of Directors is responsible for the stewardship of the Company and the supervision of management of the business and affairs of the Company. The Board's accountabilities and responsibilities include development of the Company's approach to corporate governance, the adoption of a strategic plan and the identification of the principal risks of the Company's business. The Board has adopted a Mandate, the text of which is set out as Appendix "B", which Appendix is hereby incorporated by reference.

Position Descriptions

The Board has adopted formal position descriptions for the Chair of the Board and the Board Committee Chairs. The position descriptions of each Committee Chair are set out in the Committees' mandates. In general, Committee Chairs are responsible for the leadership of their Committee as well as reporting to the Board on behalf of the Committee. The Board of Directors has also adopted a position description for the President and Chief Executive Officer, which sets out the key roles and responsibilities for that position.

Committees of the Board of Directors

The Board of Directors has established five standing committees of the Board and delegates certain of its enumerated responsibilities to each of the Committees. Notwithstanding this delegation, the Board retains its oversight function and ultimate responsibility for all matters delegated to committees.

The five standing committees of the Board are the Audit and Finance Committee, the Corporate Governance Committee, the Human Resources and Public Policy Committee, the Regulatory and Environment Committee and the Health and Safety Committee. The roles and responsibilities of each Committee are set out in formal written Mandates. These Mandates are reviewed at least annually to ensure that they reflect best practices as well as applicable regulatory requirements. A brief summary of each of the Committees' responsibilities follows.

Audit and Finance Committee

The Audit and Finance Committee is composed entirely of independent directors as required by the CSA Rules (for more information, see the mandate of the Audit and Finance Committee which is attached). The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures, financial compliance and ethics policies.

Corporate Governance Committee

The Corporate Governance Committee is composed entirely of independent directors. The Committee acts as the nominating Committee of the Board of Directors and recommends director candidates, committee assignments, director compensation, and corporate governance policy for committees and the board as a whole. The Committee reviews the general and specific criteria applicable to candidates to be considered for nomination to the Board. The objective of this review is to maintain the composition of the Board in a way that provides the best mix of skills and experience to guide the long-term strategy and ongoing business operations of the Company. In addition, the Committee leads an annual evaluation of the Board and makes recommendations on modifications of the evaluation process.

Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is composed entirely of independent directors. The Committee recommends compensation policy for senior managers, leads the performance review of the Chief Executive Officer, recommends bargaining strategy with respect to the unions, and advises the board on public policy matters and corporate social responsibility issues. In this regard, the Committee also reviews succession planning and the recommendations for the appointment of persons to senior executive positions. In 2005, Hay Management Consultants were retained to review and provide advice on management compensation. For additional information relating to the compensation of the Company's senior executives, see "Statement of Executive Compensation".

Regulatory and Environment Committee

The Regulatory and Environment Committee monitors the Company's compliance with regulatory and environmental requirements and related risk, reviews related policies and generally oversees processes and procedures related to regulatory and environmental compliance at the Company.

Health and Safety Committee

The Health and Safety Committee advises the Board on health and safety policies and standards, oversees compliance with health and safety regulations at the company, and reviews and reports to the Board on the company's emergency preparedness.

Orientation and Continuing Education

Upon joining the Board, all new directors are given a Directors Guide to provide them with an overview of the key organizational, financial, regulatory, and operational aspects of the Company. The Directors Guide also contains information on the structure of the Board and its committees, committee mandates and general information on a director's obligations. In addition, new directors receive a tour of our companies' facilities and briefing sessions with senior management. Orientation sessions with senior management and facility tours provide directors with a thorough understanding of the Company's business to assist them in the performance of their legal obligations and duties as directors.

On an on-going basis, as part of regular Board meetings, directors receive presentations and reports on topics related to the Company's business. These information items are either suggested by management or may be requested by members of the Board. As well, directors receive information from management through the mail in response to any actions arising at a board meeting or otherwise.

Ethical Business Conduct

The Board has adopted a written Code of Business Conduct ("Code"). The Code sets out a comprehensive set of principles and expectations relating to ethical conduct, conflicts of interest and compliance with laws. The Code is part of Hydro One's internal control framework and applies to all of Hydro One's directors, officers and employees. The Code also applies to Hydro One's agents, consultants, contractors and business partners, to the extent feasible. The Code is posted on the corporate intranet site and on the external corporate website at www.HydroOne.com.

The Company has a Corporate Ethics Officer who is accountable for making sure that the appropriate actions are taken to investigate and resolve known or suspected violations of the Code, and for ensuring the tracking and reporting of all violations. The Board monitors compliance with the Code through the Human Resources and Public Policy Committee and the Audit and Finance Committee, to whom the Corporate Ethics Officer reports. The Chief Executive Officer is ultimately responsible for the Company's compliance with the Code. Further, the Board of Directors abides by a conflict of interest policy which requires directors to

exercise independent judgment when considering transactions and contracts in respect of which a director has a material interest.

Board, Committee and Director Assessments

A process is in place for evaluating the effectiveness of the Board of Directors and its Committees. The process consists of a written questionnaire that is completed annually by each Director. The questionnaire addresses the areas of board responsibility, operation and effectiveness. The Directors' responses to the questions are compiled into a report that is reviewed by the Corporate Governance Committee to determine any actions that may need to be taken. The report is then reviewed by the Board. In addition to the written questionnaire, the Chair of the Board also meets with each director about individual performance and the effectiveness of the Board.

**APPENDIX “A”
AUDIT AND FINANCE COMMITTEE MANDATE**

1. Pursuant to By-Law No. 1 of Hydro One Inc. (the “Corporation”), a committee of the directors to be known as the “Audit and Finance Committee” (hereinafter referred to as the “Committee”) is hereby established.
2. The Committee shall be composed of a minimum of four directors, and have membership attributes consistent with applicable requirements under the *Securities Act* (Ontario) and regulations thereunder including:
 - Independence. The Committee shall be comprised of directors who shall meet the independence and audit committee composition requirements set forth by applicable securities regulatory authorities, or any governmental or regulatory body exercising authority over the Corporation, as in effect from time to time. A member cannot accept consulting, advisory or compensatory fees, other than compensation for directors’ fees and expenses, from the Corporation.
 - Financial Literacy. All members are to be financially literate (or shall become financially literate within a reasonable period of time after appointment to the Committee). A member is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation’s financial statements.
3. The members of the Committee shall be appointed or re-appointed at the Organizational Meeting of the Board of Directors (the “Board”) immediately following each annual meeting of the Shareholder of the Corporation. Each member of the Committee shall continue to be a member thereof until his or her successor is appointed, unless such member shall resign or be removed by the Board or shall cease to be a director of the Corporation. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and shall be filled by the Board if the membership of the Committee is less than four directors as a result of the vacancy. Whenever there is a vacancy on the Committee, the remaining members may exercise all of the powers of the Committee as long as a quorum remains in office.
4. The Board or, in the event of its failure to do so, the members of the Committee, shall appoint a Chair from amongst their number. If the Chair of the Committee is not present at any meeting of the Committee, the Chair of the meeting shall be chosen by the Committee from among the members present. The Committee Chair shall be responsible for the leadership of the Committee, including the preparation of the agenda, presiding over meetings and determining Committee assignments. The Chair presiding at any meeting of the Committee shall have a casting vote in case of deadlock. The Committee shall also appoint a Secretary who need not be a director.
5. The time and place of meetings of the Committee and the procedure at such meetings shall be determined from time to time by the members thereof provided that:

- (a) a quorum for meetings shall be three members, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak and hear each other;
 - (b) the Committee shall meet at least quarterly; and
 - (c) notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Committee, the internal auditors and the external auditors of the Corporation at least 24 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive a notice of a meeting; and attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called. The Committee may request the external auditors to attend a meeting or meetings of the Committee, the expense of which shall be paid by the Corporation and included within the external auditors' annual fee. A meeting of the Committee may be called by the Secretary of the Committee on the direction of the Chair or Chief Executive Officer of the Corporation, by any member of the Committee, the external auditors or internal auditors. Notwithstanding the provisions of this paragraph, the Committee shall at all times have the right to determine who shall and shall not be present at any part of the meeting of the Committee.
6. The Committee Chair is responsible for reporting to the Board on behalf of the Committee on matters considered by the Committee, its activities and compliance with this mandate.
7. For purposes of this Section, the term "Corporation" shall include Hydro One Inc. and its subsidiary entities, as defined by Multilateral Instrument 52-110 Audit Committees.

The Committee shall:

- (1) in connection with its advisory functions:
 - (a) review the internal audit procedures of the Corporation and advise the Board on its auditing practices and procedures and obtain adequate assurance that internal controls are adequate;
 - (b) meet separately with the external auditors and internal auditors and report to the Board on such meeting;
 - (c) review the recommendations of the officers of the Corporation as to the reappointment or appointment of external auditors and make recommendations to the Board with respect to the nomination and remuneration of external auditors to be appointed at each annual meeting of the Shareholder. If a change in external auditors is proposed, the Committee will inquire as to the reasons for the change, including the response of the incumbent auditors, and inquire as to the qualifications of

the newly proposed auditors before making its recommendation to the Board;

- (d) review periodically, reports on the nature and extent of compliance with requirements regarding statutory deductions and remittances, including deductions and remittances under the *Income Tax Act* (Canada), the *Excise Tax Act* (Canada) and the *Unemployment Insurance Act* (Canada), the nature and extent of non-compliance together with the reasons therefore and the plan and timetable to correct deficiencies and report to the Board on the status of such matters;
 - (e) review and reassess the Committee's mandate at least annually and report to the Board results of the review, including any recommended changes to the mandate;
 - (f) the Committee shall meet with management to review and assess the process and systems in place for the review of public disclosure documents that contain audited and unaudited financial information and their effectiveness;
 - (g) describe in the annual information form all information about the Committee as required by applicable securities regulatory authorities; and
 - (h) review and assess with management and recommend to the Board for approval any material transaction, contract or other matter involving the Corporation and a shareholder, or other person, which owns directly or indirectly voting securities of the Corporation. For this purpose, "material" means any transaction, contract or matter that significantly affects, or would reasonably be expected to have a significant effect on, the financial position of the Corporation or the market price or value of its securities.
- (2) In connection with the exercise of its powers:
- (a) review and recommend to the Board for approval:
 - (i) the audited annual financial statements of the Corporation, the annual management discussion and analysis ("MD&A") and any required annual MD&A supplement and related press releases before the Corporation publicly discloses this information;
 - (ii) the Corporation's interim (quarterly) financial statements, interim MD&A and any required interim MD&A supplement and related press releases before the Corporation publicly discloses this information, unless the Board delegates to the Committee such approval authority as provided in paragraph (b) below;

- (iii) all financial statements in prospectuses and other offering memoranda, and financial statements required by securities regulatory authorities;
 - (iv) the annual information form of the Corporation and any other similar disclosure required to be filed by securities regulatory authorities;
 - (v) any prospectus, offering memorandum of the Corporation, or any amendments thereto. For the purpose of this mandate, reference to “prospectus” includes a preliminary prospectus, a prospectus, or an amendment thereto, but excludes a pricing supplement; and
 - (vi) the annual financing plans and objectives of the Corporation including, foreign currency risk and interest rate risk strategies.
- (b) subject to the authority delegated by the Board, review and approve the Corporation’s interim financial statements, interim MD&A and any interim MD&A supplement, and review and approve the related press releases;
 - (c) discuss with the external auditors results of their review of the interim financial statements and interim MD&A, including any matters external auditors may raise with audit committees under generally accepted accounting principles and auditing standards in compliance with applicable securities laws and regulations;
 - (d) review the issuance under a shelf prospectus of the Corporation of debentures, notes and/or other unsecured and secured evidences of indebtedness of the Corporation, in accordance with the authority delegated by the Board and the filing with securities regulatory authorities of any prospectus supplement relating thereto;
 - (e) review and oversee the audit plans of the internal auditors and review, pre-approve and directly be responsible for overseeing the work of the external auditors of the Corporation engaged for the purpose of preparing or issuing an auditor’s report or performing other audit, review or attest services for the Corporation, including the resolution of any disagreements between management and the external auditors regarding financial reporting. The Committee has the authority to communicate directly with the internal and external auditors.

The Committee shall also review the degree of co-ordination between the audit plans of the internal auditors and the external auditors and will inquire as to the extent the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts. Any significant recommendations made by the auditors for the strengthening of internal controls will be reviewed;

- (f) pre-approve all audit and non-audit services to be provided to the Corporation by its external auditors. In connection with non-audit services, the Committee shall adopt specific policies and procedures for the engagement of non-audit services ensuring that the non-audit service is not prohibited or restricted by securities regulatory authorities. The Committee may also delegate to one or more of its members the authority to pre-approve audit and non-audit services, in which event the pre-approval of audit and non-audit services by any such member must be presented to and ratified by the Committee at its first scheduled meeting following such pre-approval;
- (g) review the internal control procedures and management's annual internal control report to ensure compliance with the law and avoidance of conflicts of interest including, without limitation, a review of policies and practices concerning officers' expenses and perquisites, including the use of the Corporation's assets;
- (h) review the duties and responsibilities of internal audit staff respecting controls, procedures and accounting practices of the Corporation;
- (i) review management programs and policies regarding the adequacy and effectiveness of internal controls over the accounting and financial reporting systems within the Corporation and, in particular, the Committee will review management's response to the internal control recommendations of the internal and external auditors;
- (j) receive and review regular reports from the internal and external auditors on the appropriateness of the Corporation's significant accounting and disclosure policies and practices and changes thereto, including any areas of management judgement and estimates that have a material effect upon the financial statements, alternative accounting treatments and their ramifications, disagreements between management and the internal and external auditors and include in the review a discussion with the external auditors of the quality, not just acceptability, of accounting principles, the reasonableness of significant judgements, and the clarity and completeness of disclosure;
- (k) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation, and the manner in which these matters have been disclosed in the financial statements;
- (l) review, at least annually, the Corporation's corporate insurance program;
- (m) annually discuss with external auditors and report to the Board the auditors' independence from management and the Corporation, and in connection, request their written confirmation of independence and disclosure of relationships they have with the Corporation that may be

thought to bear on independence, including non-audit related services and fees and their impact;

- (n) review the minutes of any audit committee meetings of subsidiary entities of the Corporation and any significant issues and auditor recommendations concerning such subsidiary entities;
 - (o) review the basis and amount of the external auditor's fees in light of the number and nature of reports issued by the auditors, the quality of the internal controls, the size, complexity and financial condition of the Corporation and the extent of internal audit and other support provided by the Corporation to the external auditors and review all other non-audit fees of the auditors or other accounting firms;
 - (p) review management's retention of consulting and professional services, including external legal services, on an annual basis;
 - (q) review and appropriately address any complaints regarding accounting, internal accounting controls, or auditing matters received since the Committee's last meeting, including complaints confidentially submitted by those wishing to remain anonymous; and
 - (r) receive and review any reports of evidence of a material violation of securities laws or breaches of fiduciary duty tabled by the Corporation's legal counsel as a result of an inappropriate response from management.
- (3) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the current and former external auditor of the Corporation.
- (4) review, at least on an annual basis:
- (a) for information purposes:
 - (i) the major risks to the Corporation's business objectives;
 - (ii) overall financing of risk, including the purchase of insurance;
 - (iii) the risk retention philosophy and risk tolerance guidelines; and
 - (iv) loss prevention policies and risk management programs;
 - (b) for approval by the Committee, the Corporation's enterprise risk management policy and framework;
 - (c) and recommend to the Board for approval all risk management strategies, including foreign currency and interest rate risk strategies.
- (5) With respect to the Hydro One Pension Plan and any replacement plan thereof, review the funding policy, the audited annual financial statements, periodic

reports detailing the asset mix status and performance of the pension fund and any further pension-related reports or policies to be submitted to the Board, including those resulting from the Terms of Reference of the Pension Committee, the Pension Plan Terms of Reference of the Board of Directors, or the Terms of Reference of the Pension Investments Unit.

8. In instances where members of the Committee believe that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of independent counsel and other expert advisers, the Committee shall have authority to engage and compensate the appropriate experts. The Board shall be kept apprised of both the selection of the experts and the expert's findings through the Committee's regular reports to the Board.

APPENDIX “B”
HYDRO ONE INC.
BOARD OF DIRECTORS
MANDATE

DUTIES OF THE BOARD OF DIRECTORS

1. The Board of Directors of Hydro One Inc. (the “Board”) is responsible for the stewardship of, and has the duty to supervise the management of, the business and affairs of the Corporation including its Subsidiaries, as defined in the *Business Corporations Act* (Ontario).
2. The Board is elected by the sole Shareholder, the Province of Ontario, as represented by the Minister of Energy (the “Shareholder”). The Board is responsible for seeking and recommending suitable Board candidates to the Shareholder.

ACCOUNTABILITIES AND RESPONSIBILITIES

The Board shall have the accountabilities and responsibilities set out below. In addition, the Board shall perform such duties as may be required under, and act in accordance with the *Business Corporations Act* (Ontario), the Corporation’s by-laws, the Agreement with the Shareholder, dated October 6, 1999 (the “Shareholder Agreement”), as may be amended from time to time, and all applicable laws.

1. Corporate Governance

- (a) The Board is responsible for developing the Corporation’s approach to corporate governance, including developing appropriate policies and procedures and delegating such other matters as it sees fit to the Corporate Governance Committee for its review and consideration.
- (b) The Board is responsible for the Corporation’s approach to its governance relationship with its sole Shareholder.

2. Strategic Planning

The Board is responsible for:

- (a) adopting a strategic planning process and approving, on at least an annual basis, a strategic plan which lays out the strategic direction of the Corporation in the context of the opportunities and risks of the business and the business and commercial environment in which it operates;
- (b) reviewing and approving the business, financial, strategic and other plans proposed by management to enable the Corporation to execute its strategy;
- (c) adopting processes for monitoring the Corporation’s progress toward its strategic and operational goals, and to revising and altering its directions to management in light of changing circumstances affecting the Corporation;

- (d) taking action when corporate performance falls short of its performance targets or other special circumstances warrant;
- (e) approving the audited financial statements, interim financial statements and the notes and management's discussion and analysis accompanying such financial statements and the Corporation's Annual Information Form; and
- (f) reviewing and approving material transactions outside the ordinary course of business, subject to the Shareholder Agreement.

3. **Risk Management**

The Board is responsible for:

- (a) identifying the principal risks of the Corporation's business and ensuring the implementation of appropriate systems to effectively monitor and manage such risks with a view to the long-term viability of the Corporation;
- (b) overseeing the integrity of the Corporation's internal control and management information systems;
- (c) approving, and monitoring compliance with, all significant policies and procedures by which the Corporation is operated; and
- (d) approving policies and procedures designed to ensure that the Corporation operates at all times within applicable laws and regulations.

4. **Human Resources Management**

- (a) The Board is responsible for approving the appointment of the President and CEO. The Board is also responsible for approving the compensation of the President and CEO following a review of the recommendations of the Human Resources and Public Policy Committee.
- (b) The Board will, to the extent feasible, satisfy itself as to the integrity of the President and CEO and other executive officers, and that the President and CEO and other executive officers create a culture of integrity throughout the organization.
- (c) The Board is responsible for ensuring that succession planning programs are in place, including programs to train, develop, monitor and retain senior management, including the President and CEO.

5. **Communications and Reporting**

- (a) The Board is responsible for approving and revising from time to time, a disclosure policy to address accurate and timely communications with the Shareholder, bondholders, employees, financial analysts, governments and regulatory authorities, the media and the public.

- (b) The Board is responsible for overseeing the Corporation's reporting to the Shareholder, responses to requests for information and other reporting obligations as set out in the Shareholder Agreement, and for ensuring open and transparent communication with the Shareholder.

6. Board Meetings and Materials

- (a) The Chair, in consultation with the President and CEO and the General Counsel and Secretary, shall develop the agenda for each Board meeting.
- (b) Meeting materials shall be provided to directors before each Board meeting in sufficient time to ensure adequate opportunity for review.
- (c) Independent directors (as defined under applicable securities legislation) shall hold regularly scheduled meetings at which non-independent directors including members of management are not present.

7. Committees of the Board

- (a) The Board discharges its responsibilities both directly and through its committees: the Audit and Finance Committee, the Corporate Governance Committee, the Human Resources and Public Policy Committee, the Health and Safety Committee and the Regulatory and Environment Committee. In addition to these standing Committees, the Board may from time to time appoint ad hoc Committees to address certain issues of a more short-term nature.
- (b) The Board is responsible for approving the mandates for each Board Committee.
- (c) To facilitate communication between the Board and each Board Committee, each Committee Chair is responsible for providing a report to the Board on material matters considered by the Committee at the first Board meeting after the Committee's meeting.

DIRECTOR DEVELOPMENT AND EVALUATION

- 1. Each new director shall participate in Hydro One's Director Education Program and any continuing director development programs.
- 2. Annually, with the assistance of the Corporate Governance Committee, the Board shall evaluate and review the performance of the Board, each of its Committees, each of the directors and the adequacy of this mandate.



**RENEWAL ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2006
FEBRUARY 16, 2007**

HYDRO ONE INC.
ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2006

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Except where otherwise indicated, all information presented herein is as at December 31, 2006.

DEFINITIONS

For convenience, in this Annual Information Form:

“**CDM**” means conservation and demand management;

“**GTA**” means the Greater Toronto Area;

“**Hydro One**”, “**our company**”, “**we**”, “**us**”, and “**our**” refer to Hydro One Inc. and its subsidiaries and predecessors, except where the context requires otherwise;

“**IESO**” refers to the Independent Electricity System Operator, previously named the Independent Electricity Market Operator;

“**IPSP**” means the Integrated Power System Plan being developed by the OPA;

“**Market Rules**” means the rules made under Section 32 of the *Electricity Act, 1998* that are administered by the IESO;

“**OEB**” refers to the Ontario Energy Board;

“**OEFC**” means the Ontario Electricity Financial Corporation;

“**OGCC**” means Hydro One’s Ontario Grid Control Centre located in Barrie, Ontario;

“**Ontario**” refers to the Province of Ontario as a geographical area;

“**OPA**” refers to the Ontario Power Authority;

“**Open Access**” refers to the opening of Ontario’s wholesale and retail electricity markets to competition which officially occurred on May 1, 2002; and

“**Province**” refers to the Government of the Province of Ontario.

CORPORATE STRUCTURE

Hydro One Inc. was incorporated as Ontario Hydro Services Company Inc. by Articles of Incorporation dated December 1, 1998 under the *Business Corporations Act* (Ontario). On May 1, 2000, we changed our name to Hydro One Inc.

Our registered office and head office is located at 483 Bay Street, 15th Floor, North Tower, Toronto, Ontario, M5G 2P5.

The following are our principal subsidiaries, each of which is wholly-owned by us and is incorporated under the laws of Ontario:

- Hydro One Networks Inc. — carries on all business relating to our ownership, operation and management of electricity transmission and distribution systems and facilities;

- Hydro One Brampton Networks Inc. — carries on the business relating to our ownership, operation and management of electricity distribution systems and facilities in Brampton, Ontario;
- Hydro One Remote Communities Inc. — carries on all business relating to our ownership, operation, maintenance and construction of generation and distribution assets used in the supply of electricity to remote communities throughout Northern Ontario; and
- Hydro One Telecom Inc. — carries on all of our business relating to leasing dark fibre and providing lit telecommunications capacity to other telecommunication carriers, large corporations, government, healthcare, and education institutions.

FORWARD-LOOKING INFORMATION

This Annual Information Form contains, and Hydro One's oral and written public communications often contain, forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business of Hydro One and the industry in which Hydro One operates and includes beliefs and assumptions made by the management of our company. Such statements include, but are not limited to, statements about the general development of our business; recent regulatory developments including the requirement to install smart meters and the expected costs to Hydro One; the expected impact of CDM programs and the IPSP; the expected completion of inter-tie projects; our strategy as it relates to safety, customer satisfaction, reliability, productivity and cost efficiency; expectations regarding key capital expenditures including investments in our distribution, transmission and telecommunications businesses; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licences, rates, rate orders and rate structures in both our transmission and distribution businesses; expectations regarding borrowing requirements; expectations regarding future pension contributions; expectations regarding environmental expenditures and other environmental matters; the nature of our relationship with the Province; expectations regarding workforce demographics and retention of key personnel; expectations regarding our strategy for acquisitions or divestitures of distribution assets; and legal proceedings in which we are currently involved. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and Hydro One disclaims any obligation to update any forward-looking statements, whether written or oral, or whether as a result of new information, future events or otherwise except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business such as a significant adverse change to the financial

markets or a natural disaster or other calamity. These assumptions are based on information currently available to Hydro One including information obtained by Hydro One from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, its business, results of operations, financial condition and its credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the potential impact of not being able to recover all of our project costs associated with the installation of smart meters;
- the potential impact of CDM programs on our load, in particular transmission;
- the potential for service disruptions and increased costs if we fail to maintain and improve our aging asset base;
- public opposition to and the failure to obtain all necessary approvals and accommodations at all or in a timely manner for projects necessary to increase transmission capacity;
- the risks related to the high number of retirements anticipated over the next few years and our potential inability to attract and retain qualified personnel;
- the inability to further improve our labour productivity and the potential for labour disputes;
- the potential for substantial and currently undetermined environmental costs and liabilities;
- the risks to our facilities posed by severe weather, other natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures, dividends and other obligations;
- the risk that we may be required to make substantial contributions to our pension plan;
- the risk that we may be subject to significant costs to complete the transfer of transmission, distribution and other assets located on Indian lands;

- the impact of the acquisition by the Province of owned lands underlying our transmission system;
- the risks associated with developing, maintaining and managing a complex information technology systems infrastructure;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated; and
- the risks associated with changes in foreign exchange and interest rates.

Hydro One cautions you that the above list of factors is not exclusive. Some of these and other factors are discussed in more detail under “Risk Factors” in this Annual Information Form. You should review the section entitled “Risk Factors” in detail.

GENERAL DEVELOPMENT OF THE BUSINESS

We are wholly owned by the Province and our transmission and distribution businesses are regulated by the OEB. Our industry, including our company, is governed within the broad legislative framework of the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended.

The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* were significantly amended by the Province during 2002. The *Reliable Energy and Consumer Protection Act, 2002*, which received Royal Assent and came into force on June 27, 2002, among other matters, clarified the Province’s rights to acquire, hold, transfer, dispose of or otherwise deal with securities, debt obligations of, or any other interest in, Hydro One and transferred, effective December 31, 2002, ownership of the transmission corridor lands from Hydro One to the Province in exchange for a statutory right to use the land for transmission and distribution purposes.

Commencing on March 1, 2004, distributors were permitted to start recovering certain distribution regulatory assets in their rates. Accordingly, in January 2004, we filed an application with the OEB for approval of distribution rate adjustments reflecting recovery of these regulatory assets for the period from Open Access to December 31, 2003. Final approval was given by the OEB on December 9, 2004. Based on this final order, we implemented rate adjustments on April 1, 2005 to recover the approved amounts.

Regulated Price Plan Structure

On April 1, 2004, the OEB implemented an interim two-tiered rate structure for the cost of electricity supplied to low volume and designated customers based on a consumption threshold of 750 kWh. On April 1, 2005, the OEB implemented a new regulated price plan structure for the cost of electricity supplied to low volume and designated customers (“RPP”). The RPP only regulates the commodity price of electricity and does not affect the rates charged for transmission and distribution of electricity and thus has minimal impact on Hydro One. The RPP maintained the two-tiered pricing structure established in 2004 but also introduced seasonal consumption thresholds. For residential customers, the price threshold is 600 kWh per month in the summer and 1,000 kWh per month in the winter. For non-residential customers, the price

threshold is 750 kWh per month in both the summer and the winter. A summary of the prices and consumption thresholds set by the RPP are as follows:

Residential Customers Under the RPP		
Winter (Nov. 1, 2005 – April 30, 2006)	Up to 1,000 kWh	5.0 cents
	More than 1,000 kWh	5.8 cents
Summer (May 1, 2006 – Oct. 31, 2006)	Up to 600 kWh	5.8 cents
	More than 600 kWh	6.7 cents
Winter (Nov. 1, 2006 – April 30, 2007)	Up to 1,000 kWh	5.5 cents
	More than 1,000 kWh	6.4 cents
Non-Residential Consumers Under the RPP		
Winter (Nov. 1, 2005 – April 30, 2006)	Up to 750 kWh	5.0 cents
	More than 750 kWh	5.8 cents
Summer (May 1, 2006 – Oct. 31, 2006)	Up to 750 kWh	5.8 cents
	More than 750 kWh	6.7 cents
Winter (Nov. 1, 2006 – April 30, 2007)	Up to 750 kWh	5.5 cents
	More than 750 kWh	6.4 cents

The OEB sets prices under the RPP at least once every 12 months, and may, upon review, reset prices more frequently to reflect updated price forecasts as well as to pass through any accumulated unexpected shortfalls or overpayments associated with the RPP. The OEB currently plans to review the need to reset prices every six months.

Ontario Power Authority

The *Electricity Restructuring Act, 2004* came into force in December 2004. It was enacted to ensure the adequacy, safety, sustainability and reliability of electricity supply in Ontario, facilitate load and demand management, encourage conservation and efficiency and regulate prices in parts of the electricity sector. In addition, the legislation created the OPA. The OPA's mandate is to ensure the adequacy and efficiency of electricity supply in the Province through planning of electricity supply and demand. See "Regulation – The Statutory and Operating Framework" for further information.

The OPA issued its Supply Mix Advice Report, which provides advice on future generation options for Ontario, on December 9, 2005 to the Minister of Energy. The Minister issued a directive to the OPA on June 13, 2006 providing direction as to the preparation of the IPSP. The Minister's directive on the IPSP included directions to strengthen the transmission system to enable the achievement of the supply mix goals set out in the directive, to facilitate the development and use of renewable energy resources in parts of the Province where the most significant development opportunities exist, and promote system efficiency and congestion reduction and facilitate the integration of new supply consistent with the need to cost-effectively maintain system reliability.

As part of the analysis and stakeholder consultation process performed in preparing the IPSP, the OPA released and circulated a series of eight discussion papers for comment. The discussion papers deal with such issues as the scope of the IPSP, the load forecast, CDM issues, supply resources, procurement options, and, of particular relevance to Hydro One, transmission issues. Discussion Paper #5: Transmission, released on November 13, 2006, assesses the present state of the transmission system in Ontario, forecasts its evolution over the next twenty years and provides recommendations on the development of 45 specific transmission projects over that timeframe. Also relevant to Hydro One is Discussion Paper #7: Integrating the Elements – A Preliminary Plan, released on November 15, 2006. Discussion Paper #7 integrates the elements discussed in each of the prior discussion papers, including the recommendations relating to load forecasting, CDM issues, supply resources, and the transmission projects referred to in Discussion Paper #5, and presents a preliminary 20-year IPSP for purposes of stakeholder discussion and feedback. The OPA recognizes that the preliminary IPSP is a work in progress that is designed to increase stakeholder understanding about the various considerations involved in developing the plan, and the OPA's intent is to further refine the preliminary IPSP into the plan that will be submitted to the OEB.

The OPA is expected to submit the final IPSP to the OEB for review and approval in 2007. The OEB may take up to a year to complete its review.

Smart Meters

The *Energy Conservation Responsibility Act, 2006* provides the framework for the installation by all electricity distributors of 800,000 smart meters by December 31, 2007 and the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. Under the legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. To date, no entity has been appointed. On July 26, 2006, the Ministry of Energy announced that they entered into an arrangement with the

IESO whereby the IESO will support the Province's smart metering initiative by coordinating and managing implementation activities.

Hydro One Network Inc.'s proportionate share of the 800,000 meters required to be installed by December 31, 2007, is 240,000. These meters are expected to be capable of measuring and reporting usage over predetermined periods, being read remotely, and providing customers with access to information about their electricity consumption. Smart meters are regarded by the Province as an integral means of promoting a culture of conservation.

Planned smart meter activities are still at an early stage. The current dynamic state of smart meter and communication technologies, especially with respect to rural applications, will likely change the cost estimates of deployment beyond 2007. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately \$75 million under our smart meter program and install 240,000 meters. At the Province's request, we will review our implementation plan and associated costs for the period from 2008 to 2010.

On March 21, 2006, the OEB approved a monthly rate of \$0.30 per residential customer, effective May 1, 2006, as initial funding for the required investment in smart meters. Our distribution rate application is expected to be filed with the OEB in February 2007 and will include a request to increase the monthly rate per residential customer for smart meter funding.

There may be an opportunity to leverage the smart meter infrastructure for smart network initiatives such as CDM, load control distribution operations automation and mobile technology. The benefits of a smart network will be assessed and included in our future investment plan as appropriate.

Conservation and Demand Management

The Province has established specific targets for CDM and Hydro One's distribution businesses have built expenditures into their plans to meet these targets. In May 2004, the Province authorized local distribution companies, including Hydro One, to apply to the OEB for the third installment of their allowable return on equity beginning March 1, 2005. The Province also indicated that the approval of the OEB would be conditional on a financial commitment to reinvest an amount equal to one year of the incremental returns in CDM initiatives. For Hydro One Networks Inc. and Hydro One Brampton Networks Inc., the total CDM revenue available was approximately \$42.7 million. Hydro One submitted CDM plans for this full amount to the OEB on January 11, 2005. On February 18, 2005, Hydro One received approval of its CDM plan on behalf of Hydro One Networks Inc. on the condition that, among other things, planned spending on smart meters for 2006 (\$7.1 million) be re-directed to other projects. On November 1, 2005 the revised plan was approved as filed, enabling total expenditures of \$39.5 million. On February 18, 2005, Hydro One Brampton Networks Inc.'s plan for \$3.2 million in CDM spending was also approved as filed. On February 2, 2005, Hydro One Remote Communities Inc. received interim approval, as requested, for a CDM plan for \$300,000. The OEB requires each distributor to file an annual report including a cost-benefit analysis by March 31 of each year in respect of the results of the previous year.

On July 13, 2006, the Ministry of Energy issued a directive to the OPA regarding the OPA assuming responsibility for organizing the delivery and funding of CDM programs through electricity distributors in Ontario. The directive recognized that distributors have a role as

delivery agents for CDM and that funding for their programs should be secure, stable and multi-year.

The directive provides guidance on key funding aspects of CDM for distributors as follows:

1. The OPA will begin organizing the delivery and funding of CDM programs through distributors immediately, with implementation of funding to occur in the earliest practical timeframe.
2. The funding will be limited to a total of \$400 million over three consecutive years.
3. Distributors would contract to deliver programs funded by an OPA-administered distributor fund on a non-competitive basis in their service territory.
4. These funds will not include provisions for smart meters.
5. The OPA should support the OEB in its continuing efforts to reduce barriers to CDM including decreases in revenues due to distributors' conservation programs.

The OPA plans to have a final plan on its approach to CDM submitted to the OEB for approval during 2007.

Government and OPA Procurement of New Generation

Over the last few years, the Province and the OPA have sought to procure new generation in Ontario. Hydro One continues to work with successful proponents under various Ontario government and OPA procurements of new generation in Ontario including the Renewables RFPs, the 2,500 MW Clean Energy RFP, the acquisition of new gas generation in the western part of the GTA and downtown Toronto, and the Combined Heat and Power RFP. Hydro One has placed a high priority on connecting these new sources of supply reliably and in a timely fashion.

Hydro One is dealing with a heavy workload driven by close to 700 applications in 2006 for assessment of proposed new small renewable generation connections to our distribution system. Work continues on hiring and training new staff to increase Hydro One's capability to perform these assessments.

Additional procurements by the OPA are likely and Hydro One's strategy and processes for dealing with the existing and anticipated connections is evolving to ensure that we are able to respond as effectively as possible. See "Risk Factors – Risks Associated with Transmission Projects."

Electricity Transfer Tax Exemption

In October 2006, the Province announced that publicly-owned utilities will be exempt from paying the electricity transfer tax when they sell electricity distribution assets to other public utilities in Ontario. The normal transfer tax payable is equal to 33% of the fair value of the municipality's interest in electricity assets transferred to another entity. The transfer tax exemption became effective on October 17, 2006 and is to last for two years. The Province indicated that the transfer tax exemption was designed to promote investment and efficiencies

among Ontario's publicly-owned electricity utilities. The Province also plans to lift the moratorium on the purchase and sale of electricity distribution assets by Hydro One, with the understanding that any future asset purchases or dispositions help further overall efficiency in the sector. We will respond, on a voluntary and commercial basis, to opportunities to purchase or divest assets where they are consistent with corporate strategy. Our investment plan does not include any funding for acquisitions or divestitures.

DESCRIPTION OF THE BUSINESS

Overview

We are the leading electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 97% of Ontario's transmission capacity as measured by revenues for the year ended December 31, 2006. Our transmission system is one of the largest in North America based on assets as at December 31, 2006. Our distribution system is the largest in Ontario based on assets as at December 31, 2006 and spans approximately 75% of Ontario, serving approximately 1.3 million customers. We have three reportable segments: (1) our transmission business; (2) our distribution business; and (3) our other business.

Our transmission business, which represented approximately \$6.97 billion of our total assets of \$12.23 billion as at December 31, 2006, transmits electricity through an approximately 28,600 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution networks, 51 local distribution companies and 64 large industrial customers directly connected to our transmission system. We also own and operate 26 facilities that interconnect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately \$5.17 billion of our total assets of \$12.23 billion as at December 31, 2006, distributes electricity through our approximately 124,700 circuit-kilometre low-voltage distribution system, including phase multipliers, to municipalities and in rural areas. Customers of our distribution business include 34 local distribution companies that are not directly connected to our transmission system, 48 large industrial customers and approximately 1.3 million rural and urban customers. Hydro One Brampton Networks Inc. is our urban distribution company, serving approximately 120,000 customers in the GTA with approximately 4,845 circuit-kilometres of lines with phase multiplier. We also operate through our subsidiary, Hydro One Remote Communities Inc., 18 small, regulated generation and distribution systems in 20 remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

Our other business segment is primarily represented by the operations of Hydro One Telecom Inc. This subsidiary markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment constituted approximately \$99 million of our total assets of \$12.23 billion as at December 31, 2006.

The OEB regulates our transmission and distribution businesses and issues rate orders to establish the revenue requirements required to cover the approved costs of these businesses plus a specified rate of return. See "Regulation – Rate Orders and Related Issues for Hydro One's Businesses – Transmission – Current Rate Orders and Distribution Rate Structure."

Recent Development

Agency Review Panel

On January 29, 2007, the Minister of Energy established a four-member panel to recommend new and updated methods of determining compensation arrangements for top provincial energy sector executives. The panel will be led by James Arnett and will also include Dave Cooke, Charles Harnick and Sharon Manson Singer. The Province is looking to the panel to recommend compensation arrangements that are more in line with comparable public energy organizations in other jurisdictions. New criteria for compensation would be reflected in future contracts of top executives. The panel will also be asked to report back to the Province on areas where energy sector effectiveness can be further strengthened, including assessments of overlap and duplication between agencies, and whether sufficient steps are being taken to address concerns about potential future shortages of skilled workers. The panel is expected to report back to the Minister with its findings concerning executive compensation arrangements in late spring of 2007. Further recommendations to strengthen energy sector effectiveness are expected to follow thereafter.

Our Strategy

In 2006, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider; by our peers as their benchmark for excellence; and by our shareholder as delivering superior value. We seek to achieve these goals by continuing to implement the following strategies:

- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on elimination of serious injury and “near misses” in high potential harm categories of work.
- *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers’ level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.
- *Reliability:* Enhance the reliability of our transmission and distribution systems. In transmission, we have assumed a proactive leadership role in developing the system to meet Ontario’s power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.

- *Employees:* Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Focusing on safety

Given the nature of our work and extreme weather conditions encountered at times, safety is of paramount importance. Our top strategic priority is to eliminate serious injuries and “near misses” that have the potential to cause serious injury. Several existing strategic initiatives that were endorsed in 2006 by our company are expected to continue and a number of existing programs are expected to be strengthened over the planning period in order to achieve and sustain the required cultural change. These initiatives include an increased focus on incident prevention and job planning, a comprehensive health and safety management system, effective management and control programs for hazardous materials and a managed system for follow-up arising from incidents and “near misses.” Our increased focus on safety is expected to enhance productivity while providing a safer work environment.

Continuing to improve our customer service focus

We are focused and committed to improving our customers’ level of satisfaction. For example, we have been actively helping our customers understand the changing industry structure, changes affecting their bills, the increased priorities on CDM, and our role in ensuring adequacy and security of supply.

For our distribution connected residential and seasonal customers, we have maintained the capability and capacity of our call centre to meet customer needs and to provide fast telephone response time and we have also expanded the services offered through our website. We have begun our roll-out of smart meter installation to provide the basis for creating an energy conservation culture across Ontario and help customers better manage their electricity use. We provide extensive customer communications to address their information needs by providing our agents with faster access to customer information and reducing the risk of telephone system failure. We utilize our Outage Response Management System to give customers better information on local outage restoration efforts.

For our generation customers, we have streamlined, consistent with the requirements of the OEB’s Distribution System Code and Transmission System Code, the processes for connecting new generators to our transmission and distribution systems.

For our mid-size business customers, we continue our assignment of our Field Superintendents to manage the customer relationship. We have found that this local presence has improved our responsiveness to our customers’ needs.

For our large transmission connected industrial customers and local distribution companies, we continue to have a dedicated account executive for each account over 5 MW of load. In addition, we have made a senior member of management available for our largest 35 customers. This gives each of these customers a senior internal contact which we believe fosters an improved relationship.

Reliability

The two prime goals of our transmission and distribution capital program over the next few years are:

- to improve, where required, the condition of our assets and to maintain them in such a manner to ensure good performance and to ensure they continue to meet reliability requirements; and
- to invest in new assets required to meet Ontario's power needs.

Transmission

We are currently top quartile in transmission reliability performance in North America for transmission systems of 230 kV and above; however, this is a moving target as comparator utilities continue to improve. Our investment plan is designed to improve reliability to remain top quartile. Transmission system capital expenditures for improving reliability are anticipated to be significant over the 2007 - 2009 period, amounting to approximately \$2.4 billion. These capital expenditures reflect investment under two broad categories: development and sustainment initiatives.

Development initiatives include transmission reinforcements and additions that allow for the transmission of power from new generation developments within Ontario and from sources of supply in other jurisdictions, to power consumers within Ontario. These projects generally support the Province's policy and direction with respect to issues such as generation development, coal fired generation shutdown, or increased ties to neighbouring transmission systems. In addition, these investments respond to the growing needs for increased power supplies by local communities within Ontario. Our investment plan includes enhancements to the transmission system to accommodate the transfer to market of new supply from nuclear and wind generation, transmission reinforcements in western GTA, Southern Georgian Bay, Woodstock and Midtown Toronto, as well as a new interconnection between Ontario and Québec.

At the local level, we continue to proactively address the supply needs with our customers to meet their load growth. For projects required to provide reliable supply to communities, the participation and support of the affected local distribution utilities as partners in joint planning studies and throughout the consultation and approval processes continues to be essential. Examples of projects initiated to meet the growing needs of our customers include new transmission stations to serve Essex County and Simcoe County, and expansions of transmission stations serving Brampton, Kingston, and Red Lake. In order to meet their future needs, we are in discussions with customers for major transmission expansions and/or new transformer stations in a number of locations including Woodstock, Oshawa and Brampton. Targeted investments in customer delivery point performance, power quality and our 115 kV and 230 kV systems are expected to lead to improved reliability.

Our investment plan also includes increased program expenditures for sustainment initiatives to manage the replacement and refurbishment of our aging transmission infrastructure. Increased emphasis is being placed on those transmission assets that are critical to support generation facilities and the unrestricted transmission of energy to our customers. Through targeted component replacement programs such as gas insulated switchgear, air blast circuit breakers, and

750 MVA autotransformers, improved performance is anticipated, which should reduce transmission outages and system integrity risks.

The timing of many of these projects and others is uncertain as they are dependent upon the IPSP which is expected to be filed in 2007 by the OPA with the OEB for its review and approval, which may take a year, and, in some instances, these projects require approval from various regulatory bodies, as well as negotiations with customers, neighbouring utilities and other stakeholders.

Distribution

Consistent with our approved 2006 distribution rate applications, capital expenditures for the period 2007 - 2009 will focus on new load connections, trouble calls and storm damage, wood pole replacement, and system capability reinforcement. Given the Province's initiatives to encourage renewable energy technologies, we also anticipate increased connection activity which could trigger the need for larger system modifications.

Distribution capital expenditures are focused on improving our aging distribution asset base in order to maintain or improve system reliability. Increasing investments are expected to be made within the distribution business, in particular reflecting increased wood pole replacements, feeder sectionalization and defect management. Across Ontario, we are continuing with the replacement of older distribution systems with higher voltage and more current-standard installations. In addition, we expect to continue to construct new lines and stations in response to system growth forecasts or high load relief requirements, and expect to continue our efforts to make the distribution system more efficient.

In addition, we are moving forward with initiatives to improve the reliability performance of our distribution system. Analysis concerning potential reliability improvement initiatives has revealed that cost-effective improvements can be achieved through improved maintenance practices and through improving the operability of the distribution system by adding sectionalizing capability at strategic locations. We expect to continue with the program started in 2005, ramping up the installation of sectionalizers to completion in 2008.

General

Virtually all of our net income in 2006 was earned from our regulated transmission and distribution businesses, which will remain our principal businesses. We intend to invest in network assets to maintain and reinforce our infrastructure. We expect to focus on our core work programs, making significant investments to improve asset condition, reduce reliability risk and increase customer satisfaction levels.

Financial

We aim to maximize the value of our company while maintaining an effective borrowing capability through stable credit quality and delivering stable financial returns to our shareholder.

We remain committed to understanding and staying abreast of best utility practices in order to execute our business in the most cost effective manner possible.

We believe that cost reductions and productivity improvements can be achieved through the joint management of our transmission and distribution businesses, the Inergi LP outsourcing arrangement pursuant to which we outsourced non-core functions to Inergi LP and the consolidation of our system operations functions. For example, we have consolidated our system operations functions, which were previously dispersed across Ontario, into the OGCC while maintaining a back-up facility in Toronto. This initiative is intended to produce lower costs and better service through the introduction of more technologically sophisticated operating tools.

Annual savings have been achieved in recent years as a consequence of our focus on operational excellence and these savings have largely been re-invested back into our work programs or have offset additional cost pressures. Going forward, we are continuing to focus on capital efficiency and workplace productivity, but additional savings opportunities are fewer, more complex and difficult to achieve.

Employees

We expect to continue to focus initiatives on the retention of key staff and the maintenance and development of the skills and competence of all our employees to manage the impacts of anticipated retirements.

A strategic goal of ours is to manage the demographics of our workforce, an issue which we are monitoring, as the average age of our work force is over 46 years with approximately 19 years of service. In response to this issue, a comprehensive management development program, as well as a succession planning program, has been implemented. See “Risk Factors – Work Force Demographic Risk.”

Our Transmission Business

Overview

Our transmission system operates at 500 kV, 230 kV and 115 kV and transmits electricity to customers consisting of 51 local distribution companies, our own distribution businesses and 64 large industrial companies that have loads greater than 5 MW. Electricity is also delivered to utilities in other jurisdictions through inter-ties. Electricity is supplied by generators, both within and outside Ontario, of which 83 in Ontario are connected directly to the transmission grid. Our transmission system serves over four million customers, directly or indirectly, and transported approximately 151 TWh of energy throughout Ontario in 2006. Revenues from our transmission business accounted for approximately 27% our total revenues in 2006 and 30% of our total revenues in each of 2004 and 2005, respectively.

Our transmission system forms an integrated transmission grid that can be divided into two components based on function. The integrated network, or bulk system, operates primarily at 500 kV or 230 kV over relatively long distances and links major sources of generation to transmission stations and larger area load centres. The area supply system operates at 230 kV or 115 kV and links the bulk system to local generators and loads, such as local distribution companies, industrial customers and our own distribution operations. Transformer stations located near load centres step down the high voltage to the level required for retail distribution systems or end-use customers connected directly to our transmission system.

Our transmission system is interconnected with the North American eastern system that is comprised of virtually all of the electric utilities east of the Continental Divide. Our transmission business owns and operates 26 inter-ties at 345 kV, 230 kV, 115 kV and 69 kV levels with New York (9), Québec (9), Michigan (4), Manitoba (3) and Minnesota (1). Due to the nature of the system, the interconnections with Québec are operated in a radial connection mode where load and/or generation is connected to either the Ontario system or the Québec system at any one time, but not to both simultaneously. This mode of operation is also required for one of the Manitoba interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In operation, the actual import and export capabilities may be restricted significantly by limitations within our or another jurisdiction's transmission networks, unscheduled power flows between interconnected systems and local load and generation patterns.

Our transmission system is currently relatively free of restrictions in its ability to supply electricity to major load centres from generating sources located across Ontario. A 500 kV system serves as the transmission "backbone" around the GTA with 500 kV connections to Northern Ontario, Ottawa, London and the major generating facilities in Ontario. As new generation projects are assessed in Ontario, the impact on the transmission system will need to be assessed.

Transmission Assets

Our transmission assets can be divided into five functional categories: transmission stations, transmission lines, transmission operations, telecommunication facilities and other transmission assets.

Transmission Stations

Transmission stations are required to integrate the transmission lines into a network and to transform the voltage of the electricity being transmitted, depending on the voltage requirements of the end user. These stations are frequently located at points at which power from two or more transmission lines can be combined and re-routed in different directions. Their main purpose is to transform voltage and, in most cases, to allow switching capabilities between transmission lines. In some instances, facilities with only switching facilities are required. A majority of our switching stations and a few voltage transformation facilities are located at Ontario Power Generation Inc.'s facilities.

Transmission stations can be broadly classified into two categories. The first category consists of terminal stations, including switchyards located at Ontario Power Generation Inc.'s generating facilities, which are used mainly for switching and voltage transformation between the 500 kV, 230 kV, and 115 kV systems. The second category consists of customer supply stations, which are transmission stations that deliver power from the transmission system to wholesale customers. Currently, most transmission stations used for customer supply consist of paired circuits and step-down transformers that are meant to ensure that the failure of any one element will not result in a permanent loss of supply. For smaller or remote loads, a simpler station design with a single transformer or a single circuit is used.

Our transmission system includes 276 transmission stations whose components may include high voltage power transformers, power circuit breakers, high voltage switches, capacitor and reactor

banks, protection and control systems, metering and monitoring systems together with site infrastructures such as buildings and security systems.

Transmission Lines

Our transmission lines are classified into bulk power lines and area supply lines. Bulk power transmission lines are main lines delivering power from generating stations or interconnections to receiving terminal stations. Bulk power transmission lines are part of the integrated transmission network and generally operate at 500 kV or 230 kV, with a few at 115 kV. Area supply lines take power from the transmission network at the receiving stations and transmit it to customer supply transformer stations at customer load centres. The usual voltage levels of area supply lines are 230 kV or 115 kV. All of these lines are overhead except for approximately 270 circuit kilometres of underground cables in urban areas.

The transmission system includes approximately 28,600 circuit kilometres of high voltage lines whose major components consist of cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems.

Transmission Operations

All of our transmission assets and much of our distribution assets are monitored, controlled and managed from one location, our OGCC in Barrie, Ontario. At the OGCC, the integrity of our transmission and much of our distribution assets are continually monitored in real time to ensure optimal performance of the network under present and potential contingencies and provide immediate response to our customers. The OGCC is fully supported by onsite customer, engineering, facilities, training and process staff. The OGCC also coordinates our extensive outage program with the various internal stakeholders and our external customers. Required outages are assessed and coordinated to minimize their impact on system security and reliability. In addition to the OGCC, there is a fully functional back-up facility located in Toronto. The back-up facility would be staffed in the event of an evacuation of the OGCC. The IESO manages the electricity marketplace and directs the operation of Ontario's integrated transmission network. Since we own and operate the largest portion of this transmission network, we have the responsibility to ensure that the direction from the IESO is safe and optimizes our asset performance and our connection performance to our customers. Accordingly, the OGCC reviews, approves, performs and/or authorizes all switching and control actions of our transmission system assets when directed by the IESO and, independently, when required to ensure public/employee safety and to maintain integrity of our assets and our connected customers.

Telecommunications Facilities

Our requirements for telecommunications include services for administrative data, voice and power system protection and operation. These requirements are met through the use of a wide range of our own facilities and services acquired from other telecommunications service providers. The reliability and availability of telecommunication services used in the protection and operation of our transmission system are vital to meeting our interconnection obligations, ensuring the protection of our assets and ensuring the reliability of our transmission system. Historically, if telecommunications service providers were not able or willing to provide the required services at an appropriate cost, we installed our own telecommunication facilities.

These owned facilities include analogue microwave radio, fibre optic cable, power line carrier and mobile radio systems. The analogue microwave radio system is nearing the end of its useful life and we are continuing its replacement with digital fibre-optic and digital microwave system. Replacement is expected to be completed in 2007.

Other Transmission Assets

Other assets include those supporting the ongoing maintenance and operation of the transmission system, such as office and service buildings, transportation and work equipment and other office and information technology assets.

Projects Relating to Interconnection Capacity

Québec

Construction began in December 2006 on a new inter-tie with the Province of Québec that would increase our inter-tie capacity by approximately 1,250 MW. This consists of a new two-circuit 230 kV line between the systems near Ottawa, along with AC-DC-AC conversion facilities in Québec needed to connect the two systems in a continuous manner (currently, load or generation is required to be isolated to either system for import or export). We expect the new inter-tie to come into service in the spring of 2009.

Michigan

Two of our inter-ties with the State of Michigan have been upgraded with the installation of two, three phase shifting transformers and an autotransformer. The phase shifters were put into operation during emergency situations in 2005 and have been tested weekly since the fall of 2005. Full operation is pending completion of an interconnection agreement with the International Transmission Company in Michigan, which is the utility to which we are connected by these inter-ties. This equipment is intended to provide us with greater control over the use of our Michigan interconnection so as to better control transactions directly across the Ontario-Michigan border and indirectly across the Ontario-New York border. As a result, we expect to increase our export capacity by 1,000 MW and our import capacity by 500 MW.

Manitoba

Hydro One and Manitoba Hydro have supported the continuing efforts by the Ontario and Manitoba governments in the development of the next steps for a Clean Energy Transfer Initiative. A Memorandum of Understanding was signed by the two governments on October 27, 2005 addressing the process to negotiate potential short and long-term agreements for power purchases by Ontario from Manitoba and the development of associated transmission facilities.

Hydro One and Manitoba Hydro have completed studies and a report on the transmission upgrade. At present, work on both the shorter-term upgrade and a potential longer term deal and development of a new 1,500 MW high capacity tie is now on hold pending further direction from the Province or the OPA. We estimate that the earliest in-service date of this project is 2014. Bringing electricity supply from the northern region of Manitoba represents an extensive and complex undertaking involving many parties.

NERC (North American Electric Reliability Council) / NPCC (Northeast Power Coordinating Council)

In North America, standards to improve the reliability and security of the interconnected bulk electric system are developed by NERC. The United States' Energy Policy Act of 2005 mandated compliance with these standards and assigned the Federal Energy Regulatory Commission ("FERC") as the regulatory agency that will approve and enforce these standards in the United States. Subsequently, FERC has approved establishment of NERC as an Electric Reliability Organization ("ERO"), with responsibility for developing reliability standards, monitoring compliance, assessing non-compliance, and applying sanctions for non-compliance.

The Market Rules mandate that we comply with the reliability standards established by NERC and NPCC and our transmission licence mandates that we comply with the Market Rules.

NERC Readiness Audit

NERC performed a Readiness Audit (the "Audit") on our OGCC during the week of June 26-29, 2006. The NERC Readiness Audit Program independently reviews the operation of registered operators of bulk power systems in North America and determines their readiness to maintain safe and reliable operations. The Audit is designed to ensure that operators of the bulk electric system have the tools, processes and procedures in place to operate reliably. NERC uses the results of these Audits to champion the changes required to improve reliability performance of these entities.

Hydro One's transmission operations facilities, processes and staff received high marks for their ability to reliably operate and maintain Ontario's electricity transmission system. The Audit results indicated: two examples of excellence, eight positive observations and five recommendations. The examples of excellence centered on OGCC's sophisticated interactive voice communication system and the extensive physical security protocol, infrastructure and procedures. The positive observations were as follows:

- Strong commitment to 100% NERC operator certification at the reliability coordinator level
- Safety elevated to a level of critical importance in all elements of operation
- Effective utilization of simulator to enhance controller training
- Intranet site to enhance training resource availability and use
- Well integrated Network Management System providing easy access to all required tools and documents
- Carefully designed, fully equipped backup centre
- Communications hub with around the clock staffing and support
- Impressive audit preparation

The Audit results recommended that Hydro One implement changes and enhancements to Hydro One's training program; maintain the current high-priority Hydro One controller NERC-certification process; review and revise interconnection agreements that predate NERC standards and/or the current Transmission System Code; complete the document management system upgrade regarding policies and procedures; and review and revise the backup control center implementation plan to consider transportation requirements for all expected scenarios.

Hydro One is moving forward in addressing all of these recommendations. Hydro One has applied to NERC and received accreditation as a NERC certified training provider, altered some training curriculum and is in the process of updating some interconnection agreements. Hydro One met the NERC requirement that the OGCC's controllers be NERC certified in 2006. During 2006, other non-controller staff at OGCC have received NERC Certification and this is expected to continue in 2007.

IESO

On September 22, 2006, Ontario Regulation 452/06, made under the Electricity Act, 1998 came into force. The regulation provided that one of the objects of the IESO was to establish and enforce standards and criteria relating to the reliability of transmission systems.

Our Distribution Business

Overview

Our distribution system provides customers with electricity distribution services through a low voltage distribution network. During 2006, approximately 29.0 TWh of electricity were delivered through the distribution system to approximately 1.3 million customers located in rural and urban areas (including approximately 120,000 urban retail customers located in Brampton, Ontario). The distribution system also serves 34 local distribution companies that are not connected directly to our transmission system, another 35 local distribution companies that are connected to our transmission system and 48 customers with loads exceeding 5 MW. The distribution system comprises approximately 124,700 circuit kilometres of lines, including phase multipliers, operating mainly at voltages of 50 kV or less and we own 1024 distribution and regulating stations together with one transmission station. Our distribution system distributes electricity from our transmission system and 104 small embedded generators. Unlike the systems found in densely populated areas that are designed to include built-in redundancy, our distribution system supplies mainly rural areas with low population densities. To provide a cost effective service to these areas, the distribution system is configured as a largely radial system, meaning that it is configured in straight lines, rather than loops, so that an outage at any point along the line causes all customers further down the line to lose power. As a result, component failures require immediate repair or replacement prior to service restoration. Revenues from our distribution business accounted for approximately 70% and approximately 72% of our total revenues in 2005 and 2006, respectively.

Distribution Assets

The electricity distribution system is made up of three components: (i) low voltage lines connecting our transmission stations to our distribution stations and to some industrial customers and local distribution companies; (ii) distribution and regulating stations; and (iii) our

distribution lines connecting the low voltage side of the distribution stations to industrial, commercial, farm, and residential customers as well as embedded local distribution companies. The three components include equipment such as poles, conductors, transformers, reclosers, protection devices and switches. Other assets include service centres and equipment, such as our transportation fleet, computing equipment and service and construction equipment.

Remote Communities

Through our subsidiary, Hydro One Remote Communities Inc., we operate 18 regulated generation and distribution systems across Northern Ontario which serve 20 remote communities that are not connected to Ontario's electricity grid, the facilities of which are owned either by us or by OEFC. These remote communities include a total of approximately 3,400 customers. Electricity used by these remote communities is produced by 57 installed diesel generators owned by us, which are supplemented by small amounts of wind or hydroelectric generation. Pursuant to Regulation 199/02 under the *Electricity Act, 1998* as later amended by Regulation 454/03, we are required, through one or more of our subsidiaries, to operate and maintain existing generation and distribution assets in, and supply electricity to, these remote communities.

Our Telecommunications Business

Our telecommunications business, which is carried on by our subsidiary, Hydro One Telecom Inc., markets dark and lit fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements. This business also markets co-location space on Hydro One Networks Inc.'s microwave towers to wireless service providers.

Employees

At the end of 2006, our Hydro One Networks Inc. subsidiary had 4,018 regular (i.e., permanent) employees comprised of 469 non-represented executive and managerial staff, 2,862 employees represented by the Power Workers' Union and 687 employees represented by the Society of Energy Professionals. In addition, our Hydro One Brampton Networks Inc. subsidiary had 43 non-represented regular staff, 101 employees represented by the Canadian Auto Workers and 41 employees represented by the International Brotherhood of Electrical Workers. We also had 1,283 non-regular (i.e., temporary) employees comprised of 7 executive and managerial staff, 633 employees represented by the Power Workers' Union, 45 employees represented by the Society of Energy Professionals and 598 employees represented by a combination of the Canadian Union of Skilled Workers (an electrical trade union) and the 16 construction building trade unions that have collective agreements with the Electrical Power Sector Construction Association. Hydro One Inc., Hydro One Remote Communities Inc. and Hydro One Telecom Inc. together have approximately 104 employees in total.

In 2005, we negotiated a three-year collective agreement with the Power Workers' Union ("PWU") which will end on March 31, 2008 and through arbitration reached a three-year agreement with the Society of Energy Professionals ("Society") which expires on March 31, 2008. The substantial majority of our employees are represented either by the PWU or Society. Furthermore, in 2005, we negotiated three-year agreements with the Canadian Auto Workers and the International Brotherhood of Electrical Workers in Brampton, both of which expire on March

31, 2008 and a three-year agreement with the Canadian Union of Skilled Workers which expires on April 30, 2008. See “Risk Factors – Labour Relations Risk.”

Outsourcing Arrangement with Inergi LP

Through our subsidiary Hydro One Networks Inc. we entered into an outsourcing services agreement with Inergi LP as of December 28, 2001. The provision of services by Inergi LP commenced on March 1, 2002. Inergi LP is an affiliate of CapGemini Canada Inc. Under the agreement, Inergi LP provides us with customer service operations and settlements, as well as supply management services, pay operations services, enterprise technology and finance and accounting services. As part of the agreement with Inergi LP, 906 of our unionized and non-unionized employees (including 770 regular and 136 non-regular employees) were transferred to Inergi LP on March 1, 2002. Under the agreement, we continue to make available, for use by the transferred employees, the assets used by them prior to the transfer of their employment, with refurbishments as needed.

The agreement has a 10-year term and has base service fees of approximately \$1 billion over the term of the agreement. Fees are subject to decreases based on optional external benchmarking analyses every three years. Cap Gemini Ernst & Young US LLC has provided a financial guarantee, as well as a performance guarantee, of the obligations of Inergi LP. The performance guarantee covers the transition period in the event that the agreement is terminated. The agreement provides for rights of termination for each of the parties, including, on the part of our company, rights of early termination for convenience and upon the occurrence of specified business events. In such cases, we are obliged under the agreement to pay specified termination fees, as well as to contribute to resulting severance and other costs. In addition, upon expiration of the agreement, we have an obligation to contribute to employee severance costs, if any, up to a maximum amount of \$10 million. See “Risk Factor – Risks Associated with Outsourcing Arrangement.”

Pension Plan

We established a defined benefit registered pension plan on December 31, 1999. Hydro One Inc. manages and invests the assets and liabilities of the pension fund as plan sponsor and administrator of the plan. As of December 31, 2006, there were 4,060 active members and 7,620 pensioners and disabled and deferred members. We are required to file a new actuarial valuation as at December 31, 2006 with the Financial Services Commission of Ontario on or before September 30, 2007. See “Risk Factors – Pension Plan Risk.”

Effective December 31, 1999, we established the Hydro One Inc. Supplementary Pension Plan to provide supplementary pension benefits. On October 30, 2001, this plan was amended to require the establishment of a trust for the purpose of creating security for payment of the supplementary pension benefits provided for therein. This trust was constituted as a Retirement Compensation Arrangement under the provisions of the *Income Tax Act* (Canada), and security was issued in the form of a letter of credit.

Insurance

We maintain insurance coverage, including liability, all risk property and boiler and machinery insurance. We also maintain other insurance coverage that is required by provincial statute,

which covers automobile liability, pesticide liability and aircraft liability. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations including damage caused by severe weather, other natural disasters or catastrophic events or for environmental remediation costs. See “Risk Factors – Risk of Natural and Other Unexpected Occurrences.”

Environmental

Although primarily regulated at the provincial level, jurisdiction over the environment is shared by Canadian federal, provincial and local governments. As a result, we are subject to extensive federal, provincial and local regulation relating to the protection of the environment that governs, among other things, environmental assessments, discharges to water and land and the generation, storage, transportation, disposal and release of various hazardous substances. See “Risk Factors – Environmental Risk.”

Environmental Management System

We have an environmental management system designed to identify environmental effects of our operations and facilities and to aid in the continual improvement of our environmental performance. We continually update our environmental management system to reflect organizational changes and progress in achieving our environmental goals.

Permits, Licences and Approvals

We are required to obtain and maintain specified permits and approvals from federal, provincial and local authorities that relate to, among other things, waste disposal, drainage works and discharges to air and water.

A number of electricity projects we undertake or propose may require environmental approvals from the federal government or the use of federal lands, including reserves and other lands subject to the *Indian Act* (Canada), and will be subject to federal environmental assessment. Additional interconnection facilities with neighbouring utilities in other provinces and states require approvals and will be subject to federal regulatory review, which may include environmental assessment. Certain projects will also be subject to the provincial environmental assessment process. A significant number of our existing projects are subject to a streamlined environmental assessment process. The scope, timing and cost of environmental assessments at either the federal or provincial level depend on the type of project and its potential for environmental impact.

Releases

Federal, provincial and municipal environmental legislation operates to regulate the release of substances into the environment through the prohibition of discharges that will or may have an adverse effect on the environment. Spills and leaks of substances occur in the course of our normal operations. We could incur fines or clean-up costs in connection with these releases. Accordingly, we have spill, leak prevention and leak mitigation programs involving the testing, replacement, repair and installation of containment systems including regasketing of transformers and sulphur-hexafluoride filled equipment. In addition, we have an emergency

response capability which we believe is sufficient to minimize the environmental impact of spills and to comply with our legal obligations.

Hazardous Substances

We manage a number of hazardous substances, such as polychlorinated biphenyls (“PCBs”), herbicides and wood preservatives. In addition, some facilities have substances present which are designated for special treatment under occupational health and safety legislation such as asbestos, lead and mercury. We have environmental management programs in place to deal with PCBs and herbicides.

We continually remove PCB-contaminated materials from service and send PCB waste for decontamination or destruction. All high voltage electrical equipment containing PCBs at concentrations greater than 10,000 parts per million has been removed from service. Some equipment containing PCB-contaminated mineral oil continues to be in service, including an estimated 18,000 distribution transformers, as well as small electrical equipment components at transmission stations. PCB-contaminated mineral oil in small transmission equipment components is tested and retro filled as part of station refurbishment programs.

On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). It is expected that these draft regulations will be finalized later in 2007. We have estimated the non-capital expenditures required to comply with these draft regulations to be between \$250 million and \$375 million. If required, most of these additional expenditures would be incurred in the 2013 to 2025 period.

We use herbicides primarily for the control of incompatible vegetation on rights-of-way, along distribution lines and on station sites. We currently use an integrated management approach toward vegetation management using manual and mechanical cutting, together with the selective use of herbicides. Herbicides are applied in accordance with the *Pesticides Act*. As indicated below, the historical use of a herbicide has contaminated some of our properties and some nearby properties.

Wood preservatives are used in wood poles to protect the wood against fungi and insects and thereby extend their service lives. In the past, we have used poles which were impregnated with pentachlorophenol. We respond to contamination problems related to pentachlorophenol migration as they arise.

Land Assessment and Remediation

We have developed a voluntary land assessment and remediation program in order to identify and, where necessary, remediate contamination related to our transmission and distribution stations, service centres and remote generating stations. It involves the systematic identification of any contamination at or from these facilities and, where necessary the development of remediation plans for Hydro One and adjacent private properties. Potential contaminants include insulating oils, substances previously used for vegetation control such as arsenic trioxide, fuel oil, gasoline, PCBs and wood preservatives such as pentachlorophenol. Phase I assessments have been completed for most of the transmission stations, service centres and remote generating stations. Limited Phase I assessments were undertaken at distribution stations given their large

number and similar operating history. Site screening involving on-site soil sampling at the areas of greatest potential for contamination have been undertaken at the majority of these sites.

The inventory of land in the program is approximately 1,562 sites. The number of sites where at least one soil or groundwater sample on site was found to be above Ministry of the Environment standards (of at least one substance of concern) is 672. We have completed the clean-up of 127 sites, which include sites where underground fuel dispensing/storage tanks were removed. Further work may be required in the event we sell or decommission any of these sites. We have developed a risk-based property ranking system to assist in establishing priorities for Phase II sampling. This system is supplemented with visual inspections of the sites and nearby receptors. Remediation and/or risk management is occurring based on Phase II results and discussions with affected property owners and regulatory authorities. The Ministry of the Environment (at the local and head office level) and local Health Departments/Medical Officers of Health are actively involved in the program.

Future costs related to the land assessment and remediation program are currently estimated at approximately \$44.5 million over the next nine years. The estimated expenditure for 2007 is approximately \$11.4 million.

Electric and Magnetic Fields

Electric and magnetic fields exist wherever electricity is used or transmitted, including electric power facilities such as transmission and distribution lines and substations, and within every building in Ontario that has electrical service. Based on current research, the consensus of the scientific community is that a public health risk from exposure to electric and magnetic fields has not been established. This is reflected in Health Canada's statement that typical exposures to electric and magnetic fields present no known health risks. We sponsor research and monitor national and international developments. Electric and magnetic fields are not currently regulated by either the federal or provincial governments and we are not aware of any current plans to regulate electric and magnetic fields.

Legal Proceedings

In connection with the reorganization of Ontario Hydro, we have succeeded Ontario Hydro as a party to various pending legal proceedings relating to the businesses, assets, real estate and employees transferred to us. We will also assume responsibility for future claims relating to the businesses, assets, real estate and employees acquired by us and arising out of events occurring prior to, as well as after, April 1, 1999. In addition to claims assumed by us, we are, from time to time, named as a defendant in legal actions arising in the normal course of business. The pending legal proceedings, which include material claims to which we are currently a defendant, are discussed below.

On September 1, 1995, Torcom Communications Inc. named Ontario Hydro as one of several defendants in a suit in the Ontario Superior Court of Justice seeking damages of \$150 million, as well as specific performance of agreements and interim injunctive relief. On October 31, 2006, this action against all the defendants was dismissed without costs.

On March 29, 1999 the Whitesand First Nation Band commenced an action in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada,

Ontario Hydro, OEFC, Ontario Power Generation Inc. and our company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations, electrical power lines and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the Band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001, as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are matters for which Ontario Power Generation Inc. would have responsibility pursuant to transfer orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects.

Health and Safety

Hydro One considers health and safety to be of paramount importance in the operation of its business and continues to maintain first quartile performance in key areas as well as to develop, implement and maintain progressive programs and initiatives. We are committed to creating and maintaining an injury-free workplace with concentrated focus on the elimination of serious injuries or close calls which have the potential to cause serious injuries. We are developing a number of programs and initiatives for accident prevention and to minimize the risk of injury to the public associated with our facilities and operations. Policies are in place for both employee health and safety and public safety.

Corporate safety performance indicators and targets have been developed to measure serious incidents, especially those involving high energy levels that have the potential to cause fatalities and very serious injuries. In addition, measures are in place to monitor the days lost as a result of a workplace injury. These indicators are monitored by management and by the Health and Safety Committee of the Board of Directors. Employee compensation is tied, in part, to success in achieving annual safety performance targets. An effective early and safe return to work process has allowed us to ensure that, when injuries occur, employees recover and return to the workplace as soon as possible.

Several programs and practices have been implemented to improve our safety performance. Actions currently underway include training programs and support for young workers, including apprentices, preserving core competencies through supervisory selection and reviewing/updating supervisory programs, improving the contracting process to provide for clear and consistent

standards for work performance, and better understanding of the human decision-making process to improve performance. Work site inspections and a safety rotation/mentoring program involving the major lines of business are also contributing to a safer workplace by identifying hazards, ensuring that proper barriers are in place before work is undertaken, as well as supporting the development and maintenance of a strong safety culture. Our incident investigation process allows us to learn as much as possible from incidents in order to develop improvements to job planning and prevent recurrences.

Hydro One has integrated the management of health and safety into a single health, safety and environment management system. Effective risk assessment and management are key elements to the successful minimization of risk and safety performance improvement. Within the organization, hazards have been identified and controls implemented to mitigate these risks.

The Auditor General of Ontario and its 2006 Annual Report

The mandate of the Office of the Auditor General of Ontario (“AG”) was expanded to include conducting audits of entities such as Hydro One as a result of amendments to Ontario’s *Auditor General Act* which came into effect on November 11, 2004. The 2006 Annual Report of the Office of the Auditor General of Ontario (the “Report”) was tabled in the Legislative Assembly of Ontario on December 5, 2006. Section 3.07 of the Report contains the results of the first value-for-money audit conducted at Hydro One under the AG’s expanded mandate. The audit pertained to the year 2005 and the controls impacted were primarily operational in nature. The AG found that Hydro One had adequate policies in place to ensure that goods and services were acquired with due regard for value for money. However, they did note that systems and procedures were not adequate to ensure compliance with corporate policies. Findings and recommendations focused on the areas of blanket purchase orders, sole-source procurement, procurement of consultants and contract staff, completeness of documentation in procurement files, business process outsourcing contract management, and the use of corporate charge cards, including cheque writing. Prior to the audit, management had been in the process of implementing various policies and procedures to strengthen controls and address previous internal audit findings in the areas examined. These actions are now complete and address many of the concerns and recommendations identified by the AG. All AG recommendations have now been implemented.

REGULATION

The Statutory and Operating Framework

General

The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended from time to time, primarily establish the broad legislative framework for Ontario’s competitive electricity market. The *Electricity Act, 1998* implemented the fundamental principles of the restructuring of Ontario’s electricity industry, enabling the implementation of open non-discriminatory access to transmission and distribution systems. The *Ontario Energy Board Act, 1998* expanded the

jurisdiction and mandate of the OEB to include regulation of the electricity and natural gas markets. Both statutes have been amended several times, as discussed in the sections below.¹

Since May 1, 2002, the date of Open Access, the prices of electricity in Ontario began to be determined by market forces in the wholesale electricity market administered by the IESO. The IESO is the centralized independent electricity system co-ordinator responsible for maintaining the security and reliability of electricity supply in Ontario and for directing the operations of the IESO controlled grid. The IESO itself is licensed by the OEB and funded through fees which are approved by the OEB and levied on all market participants. See “Regulation – Contractual Arrangements, Codes and Licences – Operating Agreement with the IESO.”

Market participants may buy and sell electricity from the wholesale spot markets, administered by the IESO. Alternatively, they may contract such transactions with each other, albeit with the obligation to schedule these transactions with the IESO.

Electricity consumers in the retail market also have a choice of suppliers. They may contract with any retailer of their choice or they may continue to be provided with standard supply service by their incumbent distributor. In either case, the distributor is obliged to continue to deliver electricity to them as long as they are connected to that distribution system. See “Regulation – Contractual Arrangements, Codes and Licences – Electricity Industry Codes.”

Each distributor, including our company, continues to have an obligation to connect and supply customers in accordance with the *Electricity Act, 1998* and the conditions of its distribution licence and rate orders. On May 1, 2002, we began to provide customers connected to our distribution system who did not choose a competitive retailer (our standard supply customers) with electricity in accordance with the provisions of the OEB’s Standard Supply Service Code and the Regulated Price Plan, where applicable. See “Regulation – Contractual Arrangements, Codes and Licences – Electricity Industry Codes.”

In May 2005, the OEB completed a consultation and review process which culminated in the issuing of the 2006 Electricity Distribution Rate Handbook. This handbook provided the framework for the OEB’s review of electric distribution utilities’ revenue requirements so that rates may be re-established based on this historical average or forecasted need for implementation by May 1, 2006. See “Regulation – Rate Orders and Related Issues for Hydro One’s Businesses – Distribution – Current Rate Orders and Distribution Rate Structure” and “Regulation – Rate Orders and Related Issues for Hydro One’s Businesses – Distribution – Rate Orders for Remote Communities.” Cost allocation issues are being addressed by a working group which began work in September, 2005. They had a filing model available in the fall of 2006, enabling distributors to subsequently file new cost allocation studies in 2007.

In addition, legislative changes created the OPA, an independent, non-profit corporation which is mandated to:

¹ Amending statutes include: *Reliable Energy and Consumer Protection Act, 2002 Electricity Pricing, Conservation and Supply Act, 2002, Ontario Energy Board Amendment Act (Electricity Pricing), 2003, Electricity Restructuring Act, 2004 and Ontario Energy Board Consumer Protection and Governance Act, 2003* and the *Energy Conservation Responsibility Act, 2006*.

- assess the adequacy and reliability of electricity resources for the medium and long term;
- forecast future electricity demand and potential for conservation and renewable energy;
- prepare an integrated system plan for generation, transmission and conservation;
- lead the planning and co-ordination of electricity conservation measures through a Conservation Bureau;
- procure new supply, and initiate the development of transmission and demand management programs by competition or by contract; and
- assist the Province in achieving alternative and renewable energy goals.

The OPA has powers to raise funds, including borrowing from the Province, and is expected to be self-financed through fees approved by the OEB. Each director of the OPA holds office as an independent director and not as a representative of any class of persons in the industry.

On July 13, 2006 the Ministry of Energy issued a directive to the OPA regarding the Ministry's decision to have the OPA assume responsibility for organizing the delivery and funding of CDM programs through distributors in Ontario. See "General Development of the Business – Conservation and Demand Management."

The role of the IESO also changed. The IESO relinquished responsibilities for medium and long-term forecasting to the OPA and for market surveillance to the OEB. Through its billing and settlement systems, the IESO is required to ensure that, over time, participants pay the true cost of electricity. It retains authority over the:

- operation of the wholesale system and the operation and reliability of the power system;
- short-term forecasting; and
- ensuring compliance with the market rules.

In its enhanced role, the OEB is responsible for:

- promoting economic efficiency and cost effectiveness in electricity generation, transmission and distribution and demand management;
- reviewing and approving the OPA's IPSP and procurement processes;
- regulating payments to generators of regulated facilities; and
- regulating all elements of electricity price, including generation, for low volume and designated consumers.

The role of electricity distributors has also been expanded to permit the undertaking of energy management. The legislation has been amended to promote the expansion of electricity supply and capacity, facilitate load and demand management, encourage conservation and efficiency and regulate prices in parts of the electricity sector. The key features of the legislative amendments which affect Hydro One's businesses, include:

- the continuation of a wholesale market structure for the purchase and sale of electricity in Ontario;
- withdrawal of the requirement for prior Ministerial approval of distribution rate applications to the OEB; and
- explicit authority of the Minister of Energy to set targets for conservation and renewable energy and guidelines for supply diversity.

Changes also arise from the *Energy Conservation Responsibility Act, 2006* which received Royal Assent on March 28, 2006. This provides the framework for the installation of smart meters in all Ontario homes and small businesses by the end of 2010. Under the legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. Distributors will own, install, operate and maintain the meters. See "General Development of the Business – Smart Meters."

Contractual Arrangements, Codes and Licences

Operating Agreement with the IESO

Under the *Electricity Act, 1998*, the IESO is required to enter into agreements with transmitters giving it the authority to direct the operations of the transmitters' systems. On June 8, 2001, we signed our 10 year operating agreement with the IESO, which sets out the specific responsibilities of both parties relating to the provision of transmission service. The agreement, among other things, identifies our facilities that will be included in the IESO controlled grid; provides that the IESO will direct the operation of the facilities of our subsidiary, Hydro One Networks Inc.; defines the respective obligations of Hydro One Networks Inc. and the IESO regarding the operation of these facilities; provides for co-ordination between Hydro One Networks Inc. and the IESO of modifications or additions to our transmission facilities; establishes the terms and conditions relating to information sharing and confidentiality, monitoring and telecommunications facilities, and the delineation of accountabilities for protection systems; and addresses issues of liability and indemnification obligations.

By contrast, the distribution portion of Ontario's network is not directed by the IESO and remains subject to the operational control of local distribution companies in accordance with the regulatory framework.

Hydro One's Relationships with Other Market Participants

Generators, local distribution companies and customers directly connected to our transmission system must enter into agreements with us to ensure reliable connection service in conformity with the Transmission System Code established by the OEB.

Some market participants, such as generators and large load customers embedded within distribution systems, are connected to the wholesale market through lines and facilities that are defined as “distribution” and owned by local distribution companies. At a minimum, under the *Electricity Act, 1998*, local distribution companies must provide non discriminatory access for eligible generators and customers to the wholesale markets administered by the IESO. The local distribution companies must advise the IESO of any conditions in their distribution system that may affect the ability of embedded generators and loads to participate in the broader IESO administered markets.

Electricity Industry Codes

The OEB has approved the Affiliate Relationships Code for Electricity Distributors and Transmitters, the Standard Supply Service Code, the Transmission System Code, the Distribution System Code, the Retail Settlement Code and the Electricity Retailer Code of Conduct. These Codes and requirements prescribe minimum standards of conduct and standards of service for transmitters, distributors and retailers in the electricity market.

The Affiliate Relationships Code for Electricity Distributors and Transmitters establishes the standards and conditions for the interaction between electricity distributors or transmitters and their affiliated companies. Accordingly, our subsidiaries through which we transmit and distribute electricity are subject to this Code. Among its primary purposes, this Code is intended to minimize the potential for a distributor or transmitter to cross subsidize competitive or non monopoly activities.

The Standard Supply Service Code governs the conduct of distributors, including our company, in their provision of standard supply service. Under the Code, a distributor’s rates for standard supply service are approved and fixed by the OEB and consist of the price for electricity and an administrative charge which is intended to allow the distributor to cover its costs of providing the service. Our rates for standard supply service were approved by the OEB. As a result of the legislative changes, on April 1, 2005, our prices for standard supply service moved from regulated levels to the levels set in the RPP. On June 16, 2005, a revised Standard Supply Service Code was issued to accommodate these changes. See “Regulation – Rate Orders and Related Issues for Hydro One’s Businesses.” Each of the Transmission System Code and the Distribution System Code sets the minimum conditions that a transmitter or distributor, respectively, must meet in carrying out its obligations to transmit or distribute electricity.

The Transmission System Code applies to all transactions and interactions between a transmitter and distributors, generators and consumers of electricity directly connected to the transmission system. On August 20, 2005, the OEB completed a three-year review of the Transmission System Code and related matters, following which it issued a revised Transmission System Code. This revised Transmission System Code implements the OEB’s June 2004 decision on principles governing issues relating to transmission system by-pass, available capacity, cost responsibility, economic evaluation and contestability. This decision allows customers to build new connections that Hydro One would otherwise have owned and operated. Compensation to Hydro One for acquired or by-passed assets is limited to the asset’s net book value. However, existing generation cannot re-connect to cause by-pass of transmission tariffs (as this does not support new generation facilities in the Province). The decision also accepts that rates may be increased as a result of such by-pass. Hydro One has undertaken initiatives and a compliance assessment process which reflects the Transmission System Code changes. In accordance with

the revised Transmission System Code, Hydro One filed a final version of its revised connection procedures on August 20, 2006.

The Distribution System Code applies to all transactions and interactions between a distributor and all retailers, generators, distributors, transmitters and electricity consumers who use the distributor's distribution system. Following a consultation with stakeholders in 2003, the OEB amended the Distribution System Code to clarify and streamline the process and requirements for connections, with changes coming into effect in March 2004. The OEB also amended the Distribution System Code to include requirements for electricity consumer security deposits to ensure consistent and equitable treatment across distributors, coming into effect in July 2004. The Distribution System Code was further revised to include an obligation on distributors to provide customers with standard safety information upon disconnection. During 2005, the OEB undertook three amendments to the Distribution System Code. These changes were required to accommodate the Ministry of Energy's standard offer program (a program to promote small generators using clean or renewable resources that are embedded in distribution systems) in concert with the OPA's initiative in this area. The intent was to address net metering as required for eligible generators and to ensure clarity and uniformity in its processes related to connections and expansions. In 2006, the OEB introduced amendments to the Distribution System Code pertaining to new connections and expansions. The changes are intended to improve the transparency of how connection costs are factored into economic evaluations for expansions and clarify the rules for a more consistent approach among distributors.

The Retail Settlement Code outlines the obligations of a distributor with respect to its relationships with other retail market participants and its role as retail market settlements administrator. The Retail Settlement Code is supported by the Electricity Distribution Rate Handbook to ensure that, subject to credit risk, distributors will not make or lose money in undertaking retail market settlements. In particular, the distributors served by our company's distribution system may have the option of receiving electricity from us rather than purchasing from the wholesale market participants. In this event, we would require increased working capital to cover accounts receivable and increased ongoing costs and would expect to recover these costs through our distribution rate order. On April 1, 2005, a revised Retail Settlement Code was issued to reflect the changes required by the RPP structure. See "Regulation – Rate Orders and Related Issues for Hydro One's Businesses."

The Electricity Retailer Code of Conduct sets the minimum standards under which a licensed electricity retailer may retail electricity. Specific requirements may apply for offers made to residential or small business consumers.

Electricity Industry Licences

During 2003, the OEB undertook a review of the licences of all electricity transmitters, distributors and generators in Ontario. The new licences have a 20-year term and incorporate the reporting and record-keeping requirements in accordance with the OEB's Electricity Reporting and Record Keeping Requirements. New licences for all of our regulated businesses were issued in 2004.

Transmission Licence

The following are the key conditions of our transmission licence:

- ***Obligation to Enter into Agreement with the IESO*** – We are required to enter into the operating agreement with the IESO, providing for the IESO's direction of the operation of our transmission system. On June 8, 2001, we signed our operating agreement with the IESO. See "Regulation – Contractual Arrangements, Codes and Licences – Operating Agreement with the IESO."
- ***Non-discriminatory Access*** – If a generator, distributor, retailer, wholesaler or customer requests that we convey electricity using our transmission system, subject to capacity constraints, we must make an offer to convey electricity on behalf of the applicant consistent with the applicable Market Rules and the Transmission System Code.
- ***Obligation to Connect*** – We may not refuse an offer to connect to our transmission system which has been made in accordance with the terms of our transmission rate order, the Market Rules and the Transmission System Code unless we are permitted to do so by the OEB, the legislation or any codes, standards or rules with which we are obligated to comply as a condition of our licence. We must respond to a request for connection within 30 business days in compliance with published connection procedures.
- ***Obligation to Maintain System Integrity*** – We must maintain our transmission system to the standards established in our agreement with the IESO, the Market Rules and any other recognized industry operating or planning standard which has been specified by the OEB.
- ***Transmission Rates*** – We may not impose charges for the transmission of electricity or connection to our transmission system except in accordance with our transmission rate order.
- ***Separation of Business Activity*** – Our transmission business must separate its financial records from those of any other business of Hydro One.
- ***Expansion of the Transmission System*** – We may not construct, expand or reinforce our transmission system or make an interconnection except in accordance with the legislation, regulations, Transmission System Code and the Market Rules. The OEB may require us to expand or reinforce our transmission system if it determines that there is a threat to security, reliability or integrity of the system. We were required to and did make our best efforts to expand our inter-tie capacity to neighbouring jurisdictions by 2,000 MW by May 1, 2005. On May 1, 2005, approvals for some projects were in place but there was limited progress on adding capacity. There are projects now underway or pending completion in Michigan and Québec. See "Description of the Business – Our Transmission Business – Projects Relating to Interconnection Capacity." The OEB has been kept informed of our progress and we have updated the OEB since May 1, 2005 to enable their assessment of our efforts.
- ***Information Disclosure*** – We are required to maintain records, provide the OEB with information it may require from time to time and inform the OEB of any material change in circumstances no more than 20 days after the date of occurrence.

- ***Restrictions on Provision of Information*** – We are restricted in our use and disclosure of information pertaining to consumers, retailers, wholesalers and generators. We must obtain consent for disclosure of such information, except in certain specified situations and inform such parties of the conditions under which their information may be disclosed without their consent.

Distribution Licences

The terms and conditions of our three distribution licences are similar to the terms and conditions of our transmission licence described above. In addition, these licences:

- ***Separation of Business Activity*** – require the distribution business to keep its financial records separate from those of the transmission business;
- ***Distribution Rates*** – create an obligation to charge rates in accordance with an order of the OEB and in accordance with the methods or techniques set out in the Electricity Distribution Rate Handbook, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code;
- ***Code Compliance*** – require compliance with the Retail Settlement Code and the Affiliate Relationships Code for Electricity Distributors and Transmitters;
- ***Commodity Rebates*** – prescribe the manner by which we must pass through any rebates from Ontario Power Generation Inc. to customers; and
- ***Obligation to Connect and Serve*** – impose the obligation on our distribution business to connect a building to our distribution system under prescribed circumstances, and to sell electricity or ensure electricity is supplied to every person connected to our distribution system, in accordance with our distribution rate orders and the Standard Supply Service Code, and to sell electricity to consumers consistent with the terms and conditions of these instruments.

Rate Orders and Related Issues for Hydro One's Businesses

The OEB approves both the revenue requirements of and the rates charged by our regulated businesses. The rates are designed to permit our businesses to recover the allowed costs and to earn a specified annual rate of return on our common equity.

The term “utility rate base” refers to the investment in regulated operations (consisting of gross plant in service, less accumulated depreciation, plus necessary working capital and excluding construction work in process). Utility rate base is used to determine the capital structure for our regulated businesses, enabling a determination of approved financing charges and return on common equity for them. In 1999, the OEB approved a capital structure for our regulated businesses of 60% debt with a weighted average cost of approximately 7.7%, 4% preferred equity with a 5.5% dividend rate and 36% common equity.

See “General Development of the Business” for a review of the considerable changes made to the regulation of utility charges since Open Access.

Transmission

Current Rate Orders and Review of the Existing Transmission Rate Structure

For 2000, the rate order issued by the OEB for our transmission business (effective on April 1, 1999) approved an annual revenue requirement of \$1.2 billion. In determining the revenue requirements, the OEB approved a utility rate base of \$5.7 billion, a level of net costs and expenses of \$549 million, and a level of payments in lieu of corporate income tax of \$139 million for 2000.

On January 15, 2001, the OEB issued another rate order which included approved transmission rates that would have only applied to our transmission customers. Subsequently, it decided to establish a process involving all electricity transmitters within Ontario to develop uniform transmission rates that would apply to all transmission customers. On April 30, 2002, the OEB approved transmission rates that apply uniformly to the hourly peak demand at any transmission delivery point in Ontario. Our approved revenue requirement and load forecast remain unchanged as a result of the adoption of uniform rates. In addition, the OEB's adoption of the uniform transmission rate reduces the financial incentive for customers to seek an alternative transmission provider. The IESO collects transmission revenues for our company and remits these to us on a monthly basis.

On October 26, 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB considered options to track net income excesses or deficiencies from OEB-approved returns for the period from January 1, 2006 until the revised transmission rates are implemented.

On November 23, 2005, we proposed to the OEB an earnings-sharing mechanism that would result in excess or deficient earnings being tracked. Excess earnings would be returned to customers in the form of transmission system expansion projects that are critical to the economic health of Ontario and secure operation of the system. On February 21, 2006, the OEB announced a decision to adopt an earnings sharing mechanism to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new rates are set. Consequently, 50% of our excess earnings recovered from customers are deferred as a regulatory liability. This decision had the effect of reducing our transmission revenues by \$33 million in 2006.

The second phase of the proceeding is currently underway. Hydro One Networks' 2007 and 2008 Transmission Revenue Requirement and Rate Application was filed with the OEB on September 12, 2006. The key approvals requested include:

- Transmission revenue requirements of \$1,263 million for 2007 and \$1,298 million for 2008, representing less than a 0.5% year over year increase on an average total customer's bill;
- Capital structure of 56% debt / 4% preferred equity and 40% common equity and a return on equity of 10.5%; and

- A formulaic approach for adjusting our revenue requirements for 2009 and 2010 to improve regulatory efficiency going forward and enable us to focus on our large work plan.

The hearing for the second phase of the 2007 and 2008 Transmission Revenue Requirement and Rate Application is expected to take place in mid-April 2007.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters such that the share of revenue allocated to Great Lakes Power Ltd. increased to reflect its approved revenue requirement. As a result, our share of overall provincial transmission revenue decreased by approximately \$13 million per year beginning in 2006. This will continue until the OEB makes a rate change as a result of our transmission application.

Current transmission rates are based on the fully allocated cost associated with providing each of the following three transmission service elements:

- ***Network services*** — the transmission network is the integrated part of our high voltage transmission system that is shared by all users and includes all 500 kV facilities, the 230 kV and the 115 kV facilities that can be classified as commonly used;
- ***Line connection services*** — connection facilities are the radial parts of our high voltage transmission system, which are dedicated to serving a single customer or generator or a group of customers or generators. Transmission line connection facilities are the radial high voltage transmission lines connecting the transformer to the network; and
- ***Transformation connection services*** — the transformation connection assets consist of the high voltage transformation facilities that step down voltages from transmission levels to distribution levels to supply customers.

In addition, electricity exports from Ontario are levied an export charge for transmission of one dollar per MWh.

Competition

Under the *Ontario Energy Board Act, 1998*, any licensed competitor can apply to the OEB for approval to build transmission network facilities in Ontario. The OEB's adoption of the uniform transmission rate reduces the financial incentive for customers to seek alternative transmission.

Customers historically had the option to build and own their own transmission connection facilities and thereby avoid paying our connection charge. Only a few large industrial customers and local distribution companies chose to do so, likely because of the significant costs of construction. Under the new regulatory framework, in addition to avoiding our connection charge, local distribution companies that own their transmission connection facilities can include these assets in their rate base and earn a regulated return. Customers will generally, however, continue to have the option to have their new connection facilities incorporated within our existing transmission transformation and line pools or to build and own their new connection

facility. We expect to continue to maintain and restore our existing connection assets, as well as bid on the construction and ownership of new facilities.

By-pass

By-pass occurs when we have invested in the provision of transmission facilities to a customer which then obtains all or part of its transmission services in another manner or takes action to avoid its use of transmission services before the rates collected have paid for the investment. Recovery of the remaining costs for the stranded facilities then necessitates higher transmission rates from the remaining customers.

In its January 2001 decision respecting transmission rate design and cost allocation, the OEB addressed the issue of by-pass where a load customer installs a generator to serve all or part of its load. The OEB decided that customers would be assessed line and transformation connection charges based on their total demand for electricity, or gross load. However, given the desire to encourage new generation and the growth anticipated in the usage of the network (which would hold us harmless from the effects of stranding), customers would be assessed network charges based on their net load. In effect, customers who generate electricity on-site can save the network charges otherwise applicable to their purchase of electricity generated by third parties. The decision to assess line and transformation connection charges based on gross loads means that on-site generators bear a portion of the costs associated with Ontario's transmission infrastructure, thereby mitigating the potentially negative effect of on-site generation on our transmission business.

Although the January 2001 decision clarified the by-pass situation and the charges to be applied to load customers which install generation, two companies, Abitibi-Consolidated Company of Canada Limited and CASCO Inc., requested relief from the obligation to pay transmission charges. Despite our opposition, on September 4, 2003, the OEB awarded both companies net load billing on their line connection and network transmission rates with retroactive application to May 1, 2002. Despite having Hydro One refund \$2.8 million in total to the two companies, the OEB disallowed a deferral account to record this amount for future recovery.

In August, 2005, following an extensive consultation process, the OEB issued a revised Transmission System Code, which implements its June 2004 decision on principles relating to transmission by-pass, among other things. See "Regulation – Contractual Arrangements, Codes and Licences – Electricity Industry Codes."

Facilities Applications

With the creation of the OPA, the process for seeking approval of future large transmission projects has changed. Such projects will have to be factored into the IPSP, which the OPA must submit to the OEB for approval. Once approved, transmitters are required to conduct an environmental assessment, as well as apply to the OEB for leave to construct. Cost recovery of the facility then needs a final approval from the OEB as part of a transmission rate application.

On November 14, 2006, the OEB issued filing requirements for transmission applications which include filing requirements for leave to construct electricity transmission projects under section 92 of the *Ontario Energy Board Act, 1998*. Until there is an OEB approved IPSP, these requirements will be used to ensure a complete review of proposed transmission projects.

Transmission Corridors

On June 27, 2002, the Province passed the *Reliable Energy and Consumer Protection Act, 2002* that provided for, among other things, ownership of all transmission corridor and abutting lands to be transferred from us to the Province in exchange for a statutory right to use the lands for transmission and distribution purposes effective December 31, 2002. Certain of these lands have been subsequently transferred back to Hydro One. See “Interests of Management and Others in Material Transactions – Relationship with Province and Other Parties – Transmission Corridors.”

Distribution

Current Rate Orders and Distribution Rate Structure

With the introduction of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, distributors were able to start recovering certain distribution regulatory assets in their rates on an interim basis, beginning March 1, 2004. On January 28, 2004, we filed an application with the OEB, to adjust our distribution rates for interim recovery of the regulatory assets identified in the *Electricity Pricing, Conservation and Supply Act, 2002* for the first year of the four year recovery period commencing April 1, 2004. On December 9, 2004, the OEB issued its final decision which approved a total of \$144 million for recovery, comprising account balances in Hydro One’s retail settlement variance accounts, market ready costs, secondary environmental deferral accounts, deferred low voltage costs and other regulatory assets.

On August 17, 2005, Hydro One filed a Distribution Rate Application seeking approval for a \$160 million increase in the 2006 revenue requirement for our distribution business to a total of \$965 million. This revenue requirement was based on achieving a 9.0% return on equity, consistent with the OEB’s guidance for setting 2006 rates. Hydro One requested the full revenue requirement to recover all costs as well as recovery of regulatory assets incurred from January 1, 2004 to April 30, 2006. An oral hearing commenced in January 2006. On April 12, 2006 the OEB granted full approval of the \$965 million revenue requirement. The return on equity was approved at 9.0%. New rates add approximately 4.8% (\$6.53 per month) to our typical residential customers’ total bill (based upon usage of 1,000 kWh per month). The new rates came into effect on May 1, 2006.

The OEB announced its intention to establish a multi-year distribution rate-setting plan for the years 2007 to 2010. The objectives of the plan are: to provide greater regulatory certainty to distributors during 2007 to 2010; to begin to drive efficiency improvements in the distribution sector; and to lay a foundation for the third generation incentive regulation mechanism. Accordingly the OEB has a number of generic processes currently underway to achieve their objectives. These processes include:

- **Cost Allocation:** On September 29, 2006, the OEB released a final report on Cost Allocation Review outlining the methodology for distributors to follow in filing with the OEB, for information purposes, a cost allocation study based on the 2006 approved revenue requirement.
- **2nd Generation Incentive Mechanism and Cost of Capital:** On December 20, 2006 the OEB issued its final report on the cost of capital and 2nd Generation Incentive Regulation Mechanism including guidelines and filing requirements for the

preparation of rate applications for 2007 rates. The recommendations include a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Rebasing of distribution rates is a critical part of the OEB's multi-year electricity distribution rate setting plan. A selection process will be employed to determine which distributors will be rebased in each of three tranche years – 2008, 2009 and 2010. The rate rebasing will be the basis on which the 3rd generation incentive regulation mechanism is applied.

We expect to file our 2007 Distribution Rate Application by the end of February 2007.

In August, 2005, Hydro One filed a distribution rate application seeking approval for a \$3 million increase in the 2006 distribution revenue requirement of Hydro One Brampton Networks Inc. to a total of \$62.1 million. This rate application follows a separate process with the OEB independent from the Hydro One Networks' distribution application. The OEB rendered its decision on April 12, 2006. The decision approved Hydro One Brampton's distribution revenue requirement of \$62.1 million. The overall impact of the decision on a typical residential customer's total bill (based upon usage of 1,000 kWh per month) is expected to be an increase of 1.2% or about \$1.30 per month.

Miscellaneous Rate Applications

On November 15, 2005, Hydro One applied to the OEB for approval of rates applicable to distributed electricity generator customers of Hydro One Networks Inc. on an interim basis until we have sufficient information to file for approval of rates based on a cost allocation study. These rates, which comprise the volumetric portion of the charge only, are intended to assist in removing a financial barrier to the implementation of distributed generation in the Province. The OEB issued its decision on April 17, 2006 in which it did not approve the interim rates.

On April 26, 2005, Hydro One received OEB approval for a rate amendment affecting embedded customers connected to the Hydro One Distribution low voltage system that are supplied from multiple delivery points at a single transformation station and who pay retail transmission charges. The amendment allows the aggregation of demand for such customers and is intended to align the basis on which they are charged retail transmission rates to with that employed by the IESO in charging transmission rates to wholesale transmission customers supplied from multiple delivery points at a single transformation station. The reduction in charges to customers will be recovered through the retail settlement variance accounts.

On December 20, 2004, the OEB approved Hydro One's time of use rate pilot program, as an aspect of our CDM program. Customers are eligible for these time of use rates if their electricity consumption in the off-peak period is at least twice that during the on-peak period.

Rate Orders for Remote Communities

Hydro One Remote Communities Inc.'s business is exempt from a number of sections of the *Electricity Act, 1998* which relate to the competitive market. For example, we continue to apply bundled rates to customers in remote communities.

On December 20, 2004, we applied to the OEB for interim approval of our CDM plan with planned expenditures of \$300,000 for a one-year program. This application was not intended to change the current rates for our remote customers in 2005, but instead, to implement a deferral account, with disposition of this account to be addressed in the next rate application. The plan was approved on an interim basis, as filed, on February 2, 2005.

On October 26, 2005, we applied to the OEB for approval of our revenue requirement and new electricity rates for our remote customers for implementation on May 1, 2006. This application requested approval of a revenue requirement of \$35.5 million, the establishment of Rural and Remote Rate Protection (“RRRP”) at its current level, adjustments to reflect anticipated fuel cost increases in 2006 and the cost of an on-going CDM program, inclining block conservation rates for our Non-Standard A Residential and General Service customers, as well as exemptions from certain sections of the Distribution System Code. On April 26, 2006, the OEB rendered a decision on the main components of the application, approving the revenue requirement, CDM program and customer rates. An amended decision, clarifying the April 26, 2006 decision with respect to RRRP was issued on May 10, 2006. The new rates were implemented on May 1, 2006.

Rural and Remote Rate Protection

In approving electricity rates for a distributor which delivers electricity to rural or remote consumers, the OEB is required to provide rate protection for prescribed classes of consumers, including those who received rural rate assistance prior to April 1, 1999, by reducing the rates that would otherwise apply.

From April 1, 1999 until the present, the amount of rate reduction for rural consumers who occupy rural residential premises is \$127 million per year less the specific amounts established for certain specified municipalities and distributors in three former remote communities.

Our remote customers received a rate reduction in the amount of \$21 million for 2002, 2003, 2004 and 2005 based on the amount that they received in 2001. In 2006, our remote customers received a rate reduction in the amount of \$21 million. This amount was set by the OEB according to the rules set out in the regulations under the *Ontario Energy Board Act, 1998*.

Under the *Ontario Energy Board Act, 1998*, a distributor is entitled to be compensated for lost revenue resulting from the rate protection regime, and all consumers are required to contribute towards the amount of any compensation to the distributors, such as our company, for rate protection. As of May 1, 2002, the amounts required to compensate the distributors were collected by the IESO and paid to us for distribution in accordance with the regulation under the *Ontario Energy Board Act, 1998*. The OEB calculates the charge to be collected by the IESO based upon the latter’s forecast of the number of kilowatt-hours of electricity that will be withdrawn from the IESO-controlled grid. Hydro One Networks maintains a variance account to track any surplus or deficit in the amount received from the IESO and from the \$127 million prescribed amount.

Hydro One Remote Communities Inc.’s business is run on a break even basis. As a result, any net earnings or loss in the year, including rural and remote rate protection amounts, is deferred in a regulatory variance account for inclusion in the calculation of future customer rates.

Competition

Under the *Ontario Energy Board Act, 1998*, there are instances in which it is appropriate for one distributor to transfer its customers to another distributor. The acquiring distributor is required to obtain amendments to its licence authorizing it to serve in a specific area, but not with exclusive distribution rights to it. The OEB convened a generic hearing in December 2003 to determine the principles which will apply to such licence amendment applications. On February 27, 2004, the OEB issued its decision, with clear principles and filing requirements to be followed for service territory amendment applications. To date, on such applications, Hydro One has co-operated with other distributors on a case-by-case basis to determine the most efficient supplier and has not had to contest any such applications.

In July 2005, as a result of three applications by distributors, another generic proceeding was convened by the OEB to determine issues relevant to inter-utility share acquisitions and amalgamations. In a decision issued on August 31, 2005, the OEB decided that the scope of its review of these applications is appropriately dictated by Section 86 of the *Ontario Energy Board Act, 1998* and its objectives as stated. It also decided that reviews of the related transaction processes themselves are beyond its purview.

RISK FACTORS

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence our major business and corporate decisions. We and the Province have entered into a shareholder's agreement relating to certain aspects of the governance of our company. This agreement requires us to consult with the Province in connection with our business plans and dividend policy and obtain approval from the Province in advance of: (i) any proposal to issue or transfer shares in our company or our subsidiaries; (ii) any major transaction which could potentially have a material effect on the financial interest of the Province; or (iii) our ability to make proxy tax payments to OEFC.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc., and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which would have an adverse impact on our business.

Regulatory Risk

We are subject to regulatory risks including the risk that rates for our transmission and distribution businesses that permit us to recover on a timely basis the estimated costs of providing service and earn approved rates of return are subject to the approval of the OEB. Our ability to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

On September 12, 2006, our subsidiary Hydro One Networks filed, with the OEB, its application and evidence in support of its 2007 and 2008 transmission revenue requirements. Operations, maintenance and administration expense levels have increased over time and, our transmission business rate base has increased, reflecting prudent expenditures, since transmission rates were initially established. However, there is the risk that these increases may be disallowed by the OEB. Any disallowed expenditures relating to past capital projects would be charged to the results of operations in the period that the OEB renders its decision. We are also seeking to change our current capital structure to a higher equity component. The increased ratio of common equity as well as an increased return on equity are expected to be challenged by the OEB and intervenor groups. Insufficient funding for our transmission business could adversely impact our financial results and the operating performance of the transmission system.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

The load we deliver, in particular transmission, could be reduced by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2007, which could significantly reduce our revenues. The OEB has recognized the need to compensate utilities for any resulting lost revenue, but the approach, level and timing of any such compensation mechanism is yet to be determined. We are also subject to risk of revenue loss from other factors. For example recent revisions to the OEB's Transmission System Code have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets (under certain conditions) and compensating us by paying the net book value of bypassed assets as well as costs of removal and environmental remediation. This code revision could result in significant future revenue loss to our transmission business. The Transmission System Code enables us to challenge investments by utility customers that may strand our assets.

There is also a risk we could be required to invest in large-scale transmission infrastructure projects or incur unexpected capital expenditures to maintain or improve our assets and to connect new third-party generation assets. The Province has passed regulations authorizing us to procure smart meters. Currently we are authorized to only recover 30 cents per residential customer per month of the associated costs in rates subject to final approval from the OEB. Total project costs are anticipated to be significant. While we expect all of these expenditures to be fully recoverable, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment and charges to operations which may have an adverse effect on our business.

Asset Condition

Hydro One continually maintains its assets to provide reliable service and to accommodate customer needs. However our installed asset base is aging and therefore requires increased maintenance, major refurbishment or replacement to maintain their performance. While we plan (subject to OEB approval) to increase capital and maintenance expenditures with respect to existing assets for the next several years to maintain their performance or replace them as they

reach the end of their life, execution of these plans is dependent on external factors. For example, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to growing loads. If we are unable to carry out these plans, in a timely and optimal manner, the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security will be compromised and the costs of operating and maintaining these assets will increase. This could have an adverse impact on our company.

Risk Associated with Transmission Projects

The amount of power which may flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating standards established by North American standards authorities (i.e., NERC and NPCC).

Within Ontario, new and expected generation expansions and load growth have increased such that parts of Hydro One's transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of Hydro One's networks to reliably transmit power from new and existing generation sources (including, expanded interconnections with neighbouring utilities) to load centres or meet customers increasing loads. As a result, investments are needed to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

These investments are, in most cases, subject to receipt of OEB approvals which can include expropriation, environmental approval(s) and consultation with First Nations (which may include accommodation) where traditional lands or lands subject to land claims are involved. These approvals may not be obtained in a timely fashion or at all. The ability to make such investments may also be impacted by public opposition to the proposed site of transmission investments.

If we are unable to make necessary investments to increase transmission capacity due to the inability to obtain approvals in a timely fashion (or at all) or due to public opposition, this could have a material adverse effect on our transmission reliability, our ability to deliver sufficient electricity, and our company.

Work Force Demographic Risk

Approximately 25% of our employees will be eligible for retirement by 2008. In some parts of the organization, the risk is much higher. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We have already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions, to opportunities in other electricity sector positions across Canada (and, in particular, in Ontario) as well as senior positions outside of the sector. Moreover, we must also continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost efficient manner. Although we believe that we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. Existing collective agreements with the PWU and the Society will expire on March 31, 2008. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers.

Environmental Risk

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. It involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination on our properties could limit our ability to sell these assets in the future.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations, governing the management of polychlorinated biphenyls (PCBs). It is expected that these draft regulations will be finalized later in 2007. We have estimated the non-capital expenditures for complying with these draft regulations to be between \$250 million and \$375 million which are in excess of amounts we have already recorded as environmental liabilities on our balance sheet. If required, most of these additional expenditures would be incurred in the 2013 to 2025 period. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possess inherent redundancy (e.g. several interconnections with utilities in other provinces and the United States) that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss, however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund capital expenditures. We have substantial amounts of existing debt which mature between 2007 and 2010, including \$395 million maturing in 2007 and \$500 million maturing in 2008. We also plan to incur total capital expenditures of approximately \$1.25 billion in 2007, \$1.35 billion in 2008, and \$1.5 billion in 2009. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The most recently filed valuation was prepared as at December 31, 2003 pursuant to which we commenced making contributions effective January 1, 2004 of approximately \$80 million per year. The next valuation is required to be prepared as at December 31, 2006 and must be filed on or before September 30, 2007. The required level of contributions effective January 1, 2007 will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we estimate annual pension contributions for 2007 and beyond to be up to \$100 million per year. A determination by the OEB that some of our pension expenditures are not recoverable from customers would have a negative impact on our company.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). See "Interest of Management and Others in Material Transactions – Relationships with the Province and Other Parties – Transfer Orders." Currently, OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately \$850,000 per year that we currently are paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing a complex information technology systems infrastructure. Computer systems are employed to operate our transmission and distribution facilities, financial and billing systems and to capture data and to produce timely and accurate information used in our business. Failures of these systems could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi LP, an affiliate of CapGemini Canada Inc. See "Description of the Business – Outsourcing Arrangement with Inergi LP." If the agreement with Inergi LP is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the functions involved, which could have a material adverse effect on our net income.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing

long-term debt is refinanced. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a one percent change in interest rates on the refinancing of long-term debt maturing in 2007 and 2008 would have an impact on net income of approximately \$2 million and \$4 million respectively.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of \$40 million. The fair value of the swap contract is not significant.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code.

DIVIDENDS

Dividends on our common shares and Series A preferred shares are declared at the discretion of our Board of Directors, and are recommended by our management based on our results of operations, financial condition, cash requirements and other relevant factors, such as industry practice and shareholder expectations.

Our company's policy is to declare and pay cash dividends on our common shares on the basis of a calculation involving our regulated net income net of preferred dividends and non-regulated net income. Any factor that adversely affects our company's net income would likely be reflected in our dividend payments.

We declared and paid to the Province annual dividends on our outstanding 100,000 common shares totalling \$332 million in 2006 as compared with \$273 million in 2005 and \$247 million in 2004. We declared and paid to the Province a total annual cumulative dividend on our outstanding 12,920,000 series A preferred shares of approximately \$18 million in each of 2006, 2005 and 2004, which was calculated at a rate of \$1.375 per annum per share, as stipulated in our company's Articles of Incorporation.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The authorized share capital of our company consists of an unlimited number of common shares (the voting shares of our company) and an unlimited number of preferred shares. As at December 31, 2006, 100,000 common shares and 12,920,000 series A preferred shares are issued and outstanding, all of which are owned directly by the Province.

All of our company's voting securities are held by the Province. Accordingly, our company is controlled by the Province.

The common shares are not redeemable or retractable. Holders of our common shares are entitled to one vote per share at meetings of the shareholders of the common shares and to receive dividends if, as, and when declared by the Board of Directors of our company. Holders of common shares are also entitled to participate, pro rata to their holding of common shares, in any distribution of the assets of our company upon its liquidation, dissolution or winding-up. The series A preferred shares, as set forth in our Articles of Incorporation, entitle our company to redeem all or any part of these shares subject to certain terms and conditions as set forth therein. These series A preferred shares are entitled to a dividend at a rate of \$1.375 per annum per share.

Our company has not issued any restricted securities.

CREDIT RATINGS

Our company's corporate credit ratings from approved rating organizations are as follows:

Rating Agency	Short-term Debt	Long-term Debt
Standard & Poor's Rating Services ("S&P")	A-1	A
Dominion Bond Rating Service Inc. ("DBRS")	R-1 (middle)	A (high)
Moody's Investors Services Inc. ("Moody's")	Prime-1	Aa3

The following information relating to credit ratings is based on information made available to the public by the rating agencies.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The rating agencies rate long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D" ("C" in the case of Moody's). Long-term debt instruments which are rated in the A category by S&P mean the obligor has a strong capacity to meet its financial commitments but are considered somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rated categories. However, the obligor's capacity to meet its financial commitments and obligations is still strong. S&P utilizes a plus or a minus modifier to indicate the relative standing within the rating category. Long-term debt instruments which are rated in the A category by DBRS are considered to be of a satisfactory credit quality, with substantial protection of interest and principal. Entities in the "A" category, however, are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. The "high" modifier indicates relative standing within this rating category by DBRS. Long-term debt instruments which are rated in the Aa category by Moody's are judged to be of high quality and are subject to very low credit risk. Moody's applies numerical modifiers to each generic rating classification from Aa to Caa. The modifier 3 indicates a ranking in the lower end of that generic rating category.

The ratings mentioned above are not a recommendation to purchase, sell or hold our company's debt securities and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant.

MARKET FOR SECURITIES

Our Debentures (7.15%) due 2010, Debentures (7.35%) due 2030, Series 1 Notes (6.40%) due 2011, Series 2 Notes (6.93%) due 2032, Series 3 Notes (5.77%) due 2012, Series 4 Notes (6.35%) due 2034, Series 5 Notes (6.59%) due 2043, Series 6 Notes (4.00%) due 2008, Series 7 Notes (3.950%) due 2009, Series 8 4.100% Extendable Step-up Notes initially due 2007, Series 9 Notes (5.36%) due 2036, Series 10 Notes (4.640%) due 2016 and Series 11 Notes (5.000%) due 2046, together with our OEFC Series 9 Notes (4.45%) due 2007 and our OEFC Series 10 Notes (4.55%) due 2007 are not listed on any exchange or similar market for securities.

Trading Price and Volume

The debt securities issued by our company are not listed on a recognized exchange or quoted on a recognized quotation and trade reporting system.

Prior Sales

Our company issued the following tranches of medium term notes in 2006:

Note	Par Value (M) (\$)	Sale Price (\$)	Gross Proceeds (\$)
Series 10 (4.64%) due 2016	300	99.937	\$299,811,000
Series 9 (5.36%) due 2036	250	99.228	\$248,070,000
Series 10 (4.64%) due 2016	150	99.201	\$148,801,500
Series 11 (5.00%) due 2046	75	99.828	\$74,871,000

DIRECTORS AND OFFICERS

Directors

The following table sets forth the name, municipality of residence and principal occupation of each of our directors, as of December 31, 2006.

Name and Municipality of Residence

Principal Occupation

Rita Burak ⁽²⁾
Toronto, Ontario
Canada
(Director since June 11, 2002 and
Chair since May 30, 2003)

Chair of the Board of Directors of Hydro One
Inc.

Sami Bébawi ^{(4) (5)}
Outremont, Québec
Canada
(Director since October 8, 2004)

Executive Vice-President,
Member, Office of the President
SNC-Lavalin Group Inc.
President, Socodex Inc.

Murray J. Elston ^{(1) (3) (4)}
Manotick, Ontario
Canada
(Director since June 11, 2002)

President and C.E.O.,
Canadian Nuclear Association

Don MacKinnon ^{(4) (5)}
Chatsworth, Ontario
Canada
(Director since June 11, 2002)

President,
Power Workers' Union

Eileen A. Mercier ^{(1) (2) (6)}
Toronto, Ontario
Canada
(Director since August 15, 2002)

Corporate Director

Walter Murray ^{(1) (3) (6)}
Bracebridge, Ontario
Canada
(Director since November 10, 2005)

Corporate Director

Kathleen O'Neill ^{(1) (2) (3) (6) (7)}
Toronto, Ontario
Canada
(Director since July 27, 2005 but resigned
effective January 24, 2007)

Corporate Director

<u>Name and Municipality of Residence</u>	<u>Principal Occupation</u>
Douglas E. Speers ^{(1) (5) (6)} Coldwater, Ontario Canada (Director since November 10, 2005)	Chairman and Director, Emco Corporation
Kenneth D. Taylor ^{(4) (5)} New York, New York USA (Director since June 11, 2002)	Chair, Taylor and Ryan Inc.
Blake Wallace ^{(2) (3) (4)} Toronto, Ontario Canada (Director since November 22, 2002)	Vice President and Director, Murray & Company

- (1) Member of the Audit and Finance Committee
- (2) Member of the Corporate Governance Committee
- (3) Member of the Human Resources and Public Policy Committee
- (4) Member of the Regulatory and Environment Committee
- (5) Member of the Health and Safety Committee
- (6) Member of the Information Technology Committee
- (7) Ms. O'Neill resigned from our Board of Directors effective January 24, 2007. Until her resignation, Ms. O'Neill was the Chair of the Corporate Governance Committee and a member of the Audit and Finance Committee, the Human Resources and Public Policy Committee and the Information Technology Committee.

Rita Burak was appointed Chair of Hydro One Inc. on May 30, 2003. She served as the Vice Chair of our Board of Directors from August 22, 2002 to May 30, 2003. She is also a Director of The Equitable Life Insurance Company of Canada and the President of a consulting partnership, The Network Executive Team, Management Consultants, Inc. and has held such posts since 2003 and 2001, respectively. Ms. Burak is the Vice Chair of the University of Guelph and a member of the University Health Network Board of Trustees and the TELUS Ontario Advisory Committee and Chair of the Toronto Community Board. From 1995 to 2000, she served as Secretary of the Cabinet in Ontario and is a Member of the Order of Ontario. Ms. Burak has been a Director of our company since June 11, 2002.

Sami Bébawi is the president of his own construction project management company, Geracon Inc. From 1999 until December 31, 2006 he was an Executive Vice President of SNC-Lavalin

Group Inc. and member of the Office of the President and President of the heavy construction company Socodex Inc. Mr. Bébawi also had the corporate responsibility in project management policy. He is an engineering graduate with a Masters Degree and has several years of experience in designing and building thermal, hydro and nuclear power plants. Mr. Bébawi is a Member of the Ordre des ingénieurs du Québec and is a adjunct professor at Concordia University, Montreal. Mr. Bébawi has been a Director of our company since October 8, 2004.

Murray J. Elston was appointed President and CEO of the Canadian Nuclear Association (“CNA”), effective January 5, 2004. The CNA is a non-profit organization that represents the nuclear industry in Canada and promotes the development and growth of nuclear technologies for peaceful purposes. He previously served as President of Canada’s Research-Based Pharmaceutical Companies, a national association representing over 60 research-based pharmaceutical companies, to which he was appointed in November 1998. From 1981 to 1994, he served as a Liberal MPP in the Ontario Legislature, where he held the positions of Minister of Health, Chairman of Management Board, Minister of Financial Institutions and Chairman of the Public Accounts Committee. Mr. Elston is past Chair of the University of Ottawa Institute of Mental Health and Research and the Chair of the Walkerton Clean Water Centre. He is also a member of the Board of the Canadian Nurses Foundation. Mr. Elston has been a Director of our company since June 11, 2002.

Don MacKinnon has been President of the Power Workers’ Union, an electricity industry workers union, since May 2000 and a lineman by trade since 1971. He was Vice-President of the Union for 11 years prior to being elected President. In 2000, Mr. MacKinnon was appointed by the Minister of Energy, Science and Technology to the Electricity Transition Committee. He was a member of the Board of Directors of the Electrical and Utilities Safety Association and the Retail Management Board of Ontario Hydro. In 2003, Mr. MacKinnon was appointed by the Minister of Energy to the government’s Electricity Conservation and Supply Task Force. In 2005, Mr. MacKinnon became a member of the Canadian Nuclear Association’s Board of Directors. Mr. MacKinnon has been a Director of our company since June 11, 2002.

Eileen A. Mercier formed her own management consulting firm, Finvoy Management Inc., specializing in financial strategy, restructuring and corporate governance issues, in 1995. Prior to that time, she was Senior Vice-President and Chief Financial Officer of Abitibi-Price Inc. As an active member of the Board of Directors of several business and not for profit institutions, Mrs. Mercier’s affiliations include: CGI Group Ltd., Teekay Shipping Corporation, ING Bank of Canada, ING Canada Inc., Shermag Inc., The University Health Network and York University. In January 2007, Mrs. Mercier was appointed Chair of the Ontario Teachers’ Pension Plan Board. Mrs. Mercier has been a Director of our company since August 15, 2002.

Walter Murray is a former Vice-Chairman and member of the Executive Committee of RBC Capital Markets. Prior to his retirement from the Royal Bank of Canada in April 2005, his 38-year career with the bank included senior responsibility for relationship cover for a portfolio of major Canadian and international accounts, Corporate Banking activities across Canada, and several executive postings, including serving as Regional Executive for RBC’s Chicago based, Midwestern USA Corporate Banking operations. Since 2000, Mr. Murray has been a member of Ivernia Inc.’s Board of Directors and Chair of its Audit Committee. Mr. Murray has been a Director of our company since November 10, 2005.

Kathleen O'Neill is a Fellow of the Institute of Chartered Accountants and a member of the Board of Directors of MDS Inc., the TSX Group Inc., and Canadian Tire Bank. Until 2005, Ms. O'Neill was a senior executive with the BMO Financial Group where her most recent position was Executive Vice-President, Personal & Commercial Development, and Head of Small Business Banking, which she held from 2002 - 2004. Prior to joining the BMO Financial Group in 1994, she was a Tax Partner with PricewaterhouseCoopers from 1988 - 1994 where she provided clients with advice on corporate structuring and international tax issues, as well as audit issues. Ms. O'Neill's extensive community experience includes Chair of the St. Joseph's Health Centre's Board of Directors, Toronto (2001 - 2003), as well as Chair of the Centre's Audit & Finance Committee (1996 - 2001), and is currently on several non-profit boards. Ms. O'Neill had been a Director of our company since July 27, 2005, but resigned effective January 24, 2007.

Douglas E. Speers is Chairman and Director of Emco Corporation, a leading Canadian distributor of building materials for the residential, commercial and industrial construction markets. Prior to his appointment as Chairman, Mr. Speers was Emco's President and CEO from 1997 - 2004. Between 1971 and 1988, he held several senior positions with Imperial Oil Ltd. in Canada and Exxon International in New York City. Mr. Speers is a Professional Engineer - Province of Ontario, and is currently the Chair of the Executive Board, Canadian Industry Program for Energy Conservation (a joint industry-Federal Government initiative); Chairman of the Services Board and member of the Advisory Board of the Richard Ivey School of Business. He is a member of the Boards of a number of privately held companies and has been a Director of our company since November 10, 2005.

Kenneth D. Taylor is Chair, Taylor and Ryan Inc., a public affairs consulting company, and is a former Chancellor of Victoria University at the University of Toronto. Mr. Taylor is on the Board of Directors of a number of companies in Canada and the United States. He is the former Canadian Ambassador to Iran and the former Canadian Consul General in New York. Mr. Taylor is the recipient of the United States Congressional Gold Medal and is an Officer of the Order of Canada. Mr. Taylor has been a Director of our company since June 11, 2002.

Blake Wallace, Q.C. is currently Vice President and a Director of Murray & Company, a full-service financial intermediary specializing in commercial, industrial and residential real estate, corporate finance, advisory services (debt and equity), privatizations and public-private partnerships. He has also served as Vice President and General Counsel of Murray & Company since 1972. Mr. Wallace is a former Vice-Chair of TVOntario and has been a Director of our company since November 22, 2002.

Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

Officers

The following table sets forth the name, municipality of residence and position of each of our executive officers as of December 31, 2006. On December 8, 2006, Mr. Tom Parkinson resigned as President and Chief Executive Officer of Hydro One and Ms. Laura Formosa was appointed President and Chief Executive Officer (Acting). Although in December 2006 we announced that a search for a permanent Chief Executive Officer had commenced, a formal search process has not yet begun and is unlikely to begin until after the report of the Agency Review Panel. See

“Statement of Executive Compensation” for information concerning payments to Mr. Parkinson upon his resignation.

<u>Name and Municipality of Residence</u>	<u>Position With Our Company</u>
Laura Formusa Toronto, Ontario Canada	President and Chief Executive Officer (Acting)
Beth Summers Oakville, Ontario Canada	Chief Financial Officer
Myles D’Arcey Ancaster, Ontario Canada	Senior Vice President, Customer Operations
Tom Goldie Mississauga, Ontario Canada	Senior Vice President, Corporate Services
Nairn McQueen Dundas, Ontario Canada	Vice President, Engineering & Construction Services
Geoff Ogram Toronto, Ontario Canada	Vice President, Asset Management
Wayne Smith Toronto, Ontario Canada	Vice President, Grid Operations

Laura Formusa was appointed as President and Chief Executive Officer (Acting) on December 8, 2006 after serving as the General Counsel and Secretary of Hydro One Inc. since January 2, 2003. She joined Ontario Hydro in 1980 and has held the positions of Assistant General Counsel and General Counsel and Secretary of Hydro One Networks Inc.

Beth Summers was appointed as Chief Financial Officer on May 7, 2004 after serving as Corporate Controller of Hydro One Networks Inc. Prior to joining our company in 2001, Ms. Summers served as Senior Manager, Assurance & Advisory Services with Ernst & Young LLP.

Myles D’Arcey was appointed as Senior Vice President, Customer Operations of Hydro One Networks Inc. on May 1, 2005. Mr. D’Arcey is also President and Chief Executive Officer of Hydro One Remote Communities Inc. He joined Ontario Hydro in 1978 and has held the position of Vice President, Station Services of Hydro One Networks Inc.

Tom Goldie was appointed as Senior Vice-President, Corporate Services of Hydro One Networks Inc. on September 16, 2002. He joined Ontario Hydro in 1977 and has held the position of Vice-President, Human Resources of Hydro One Inc.

Nairn McQueen was appointed as Vice President, Engineering & Construction Services of Hydro One Networks Inc. on August 28, 2002. Prior to joining Hydro One Network Services Inc. in 2000 as Director of Engineering, Mr. McQueen was V.P., Engineering and Project Management Services for Agra Monenco.

Geoff Ogram was appointed Vice President, Asset Management of Hydro One Networks Inc. on January 1, 2005. He joined Ontario Hydro in 1981 and has held the position of Vice President, Strategy & Development of Hydro One Networks Inc.

Wayne Smith was appointed Vice President, Grid Operations of Hydro One Networks Inc. on January 1, 2005. He joined Ontario Hydro in 1980 and has held the position of Director of Investment Planning and Asset Management of Hydro One Networks Inc.

There is no family relationship between any director or officer and any other director or officer.

Indebtedness of Directors and Executive Officers

As of February 1, 2007 and since the beginning of the most recently completed financial year of Hydro One, no director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of Hydro One or any of its subsidiaries had any outstanding indebtedness to Hydro One or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Hydro One or any of its subsidiaries other than certain mortgage subsidy payments to Mr. Parkinson, former President and Chief Executive Officer of Hydro One Inc., as described under "Statement of Executive Compensation – Executive Compensation" beginning on p. 66 below.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Relationships with the Province and Other Parties

Overview

The Province of Ontario owns all of our outstanding shares. As a result, the Province has the power to control all governance decisions affecting us, including the composition of our Board of Directors. Accordingly, the Province exercises control over our policies, the acquisition or disposition of assets, the incurrence of further debt and the payment of dividends to holders of our common and preferred shares.

The OEB is the principal regulator of Ontario's electricity industry. The Province appoints the members of the OEB and fills any vacancies on the OEB. The OEB is obligated to implement approved directives of the Province concerning general policy and objectives to be pursued by the OEB and other directives aimed at addressing existing or potential abuses of market power by industry participants. The IESO directs the operation of our transmission system. The board

of directors of the IESO, other than its chief executive officer, is appointed by the Province in accordance with the regulations in effect from time to time under the *Electricity Act, 1998*.

Transfer Orders

The transfer orders pursuant to which we acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer any asset, right, liability or obligation where the transfer would constitute a breach of the terms of any such asset, right, liability or obligation or a breach of any law or order. The transfer orders also did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). The transfer of title to these assets did not occur because authorizations originally granted by the Canadian Minister of Indian and Northern Affairs for the construction and operation of these assets could not be transferred without the consent of such Minister and the relevant Indian bands or bodies or, in several cases because the authorizations had either expired or had never been properly issued. These assets consist primarily of approximately 82 km of transmission lines and distribution lines used to deliver electricity on reserves (of which 14 km of lines are used solely for serving customers off the reserves). OEFC holds these assets.

We are obligated under the transfer orders to manage both the assets held in trust until we have obtained all consents necessary to complete the transfer of title to these assets to us and the assets otherwise retained by OEFC that relate to our businesses. We have entered into an agreement with OEFC under which we are obligated, in managing the assets, to take instructions from OEFC if our actions could have a material adverse effect on it. OEFC has retained the right to take control of and manage the assets, although it must notify and consult with us before doing so and must exercise its powers relating to the assets in a manner that will facilitate the operation of our businesses. The consent of OEFC is also required prior to any disposition of these assets.

The Province also transferred officers, employees, assets, liabilities, rights and obligations of Ontario Hydro in a similar manner to its other successor corporations. These transfer orders include a dispute resolution mechanism to resolve any disagreement among the various transferees with respect to the transfer of specific assets, liabilities, rights or obligations.

The transfer orders do not contain any representations or warranties from the Province or OEFC with respect to the transferred officers, employees, assets, liabilities, rights and obligations. Furthermore, under the *Electricity Act, 1998*, OEFC was released from liability in respect of all assets and liabilities transferred by the transfer orders, except for liability under our indemnity from OEFC as discussed below. By the terms of the transfer orders, each transferee indemnifies OEFC with respect to any assets and liabilities not effectively transferred and is obligated to take all reasonable measures to complete the transfers where the transfers were not effective.

Indemnities

OEFC indemnified us with respect to the failure of the transfer orders to transfer any asset, right or thing or any interest therein related to our business to us and some of our subsidiaries, some adverse claims or interests of third parties or based on title deficiencies arising from the transfer orders, except for some claims and rights of the Crown, and claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgment, settlement or payment in connection with litigation initiated by some utilities

commissions. The Province has unconditionally and irrevocably guaranteed to us and our subsidiaries the payment of all amounts owing by OEFC under its indemnity.

The indemnity specifically excludes any matter for which we have agreed or are required to indemnify OEFC pursuant to or in connection with any transfer order. It also excludes any claim related to any aboriginal title or rights or the absence of a permit, right-of-way, easement or similar right in respect of lands held for Indian bands under the *Indian Act* (Canada). It also excludes any payment made, or loss, expense or liability incurred by us as a result of the failure of a transfer order to transfer any asset of Ontario Hydro described in the provisions of the transfer order relating to ineffective transfers.

The indemnity does not cover the first \$10,000 in value of each claim and only applies to the amount by which the total of all claims exceeds \$10 million. We are obliged to pay OEFC a fee for the indemnity of \$5 million per year until such time as the parties agree that the indemnity should be terminated. We anticipate that we will require the indemnity until all indemnifiable claims have been identified and finally determined by a non-appealable court order. The indemnity ceases to be available to any of our subsidiary corporations if we cease to control them unless the cessation of ownership results from the sale of the shares of a subsidiary in connection with the enforcement of security on such shares by an arm's-length creditor of Hydro One. The indemnity can be assigned under some conditions with the consent of the Minister of Finance.

The Province has also agreed to indemnify the directors of Hydro One for any liabilities reasonably incurred by them in respect of any civil, criminal or administrative action or proceeding to which they are made a party to the extent that these liabilities result from a claim or determination that their approval of the indemnity by OEFC constituted a breach of their duty to exercise the care, diligence or skill that a reasonably prudent person would exercise in comparable circumstances.

We have indemnified OEFC in respect of the damages, losses, obligations, liabilities, claims, encumbrances, penalties, interest, deficiencies, costs and expenses arising from matters relating to our business and any failure by us to comply with our obligations to OEFC under agreements dated as of April 1, 1999. These obligations include obligations to employ the employees transferred to us under the transfer orders, make and remit employee source deductions, i.e., tax withholding amounts, and employer contributions, manage the real and personal properties which OEFC continues to hold in trust or otherwise and take any necessary action to transfer all of these properties to us, to pay realty taxes and other costs, provide access to books and records and to assume other responsibilities in respect of the assets held by OEFC in trust for us.

Indebtedness

Hydro One incurred debt, on behalf of Hydro One and some of our subsidiaries, in connection with the acquisition of substantially all of the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses. The aggregate principal amount of this debt outstanding as at December 31, 2002 was approximately \$2.5 billion and was held by OEFC in the form of notes with varying interest rates and maturity dates from 2002 to 2007. On February 20, 2003, we issued approximately \$213,727,000 of additional notes to OEFC pursuant to an agreement between us and OEFC dated February 20, 2003 to evidence payment by us to OEFC of an amount to reduce the rate of interest payable on certain of the then outstanding notes. On March 5, 2003, OEFC sold approximately \$2.1 billion of these

outstanding notes in a public offering in the Canadian debt capital markets. As a result of this transaction, our company no longer has any indebtedness to OEFC.

Transmission Corridors

On June 27, 2002, the Province passed the *Reliable Energy and Consumer Protection Act, 2002* that provided for, among other things, ownership of all transmission corridor and abutting lands to be transferred from us to the Province in exchange for a statutory right to use the lands for transmission and distribution purposes effective December 31, 2002. Corridor land totalling 49,673 acres with a net book value of approximately \$259 million was transferred to the Province. In addition, ownership of land assets with a net value of approximately \$7 million, not then in use, was transferred to the Province and applied as a reduction of shareholder's equity. We also retained the obligation to incur certain ongoing expenditures related to our use of this land, including maintenance, property taxes and any future environmental remediation work that may be required by the Province. The OEB is authorized to restrict or discontinue any use of the transmission corridor lands that interferes with the transmission system. The Province later decided to return certain lands to us. During 2003-2005, the Province returned approximately 7,271 acres of lands with a net book value of \$38.2 million.

Operational Matters

Hydro One receives its revenues, which are in part collected by the IESO from customers, in accordance with the rules established under the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, as amended from time to time.

Hydro One and the IESO have entered into an operating agreement, which took effect in May 2002, setting out the specific responsibilities of both parties relating to the provision of transmission service. Hydro One also purchases power from the IESO administered spot market (which was administered by Ontario Power Generation Inc. prior to May 2002).

Hydro One has several service agreements with the other successor corporations to Ontario Hydro, primarily Ontario Power Generation Inc. These services include field and engineering, logistics, corporate, telecommunications and information technology services.

Payments in Lieu of Corporate Taxes

We and our subsidiaries are exempt from taxes under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) because we are wholly owned by the Province and each of our subsidiaries is, in turn, wholly owned (directly or indirectly) by us. However, pursuant to the *Electricity Act, 1998*, we and each of our subsidiaries are required to pay amounts to OEFC, which are referred to as payments in lieu of corporate taxes or proxy taxes, in respect of each taxation year, generally equal to the amount of tax that we would be liable to pay under the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) if we were not exempt from taxes thereunder.

Shareholder's Agreement and Dividend Policy

We have entered into a shareholder's agreement with the Province relating to our corporate governance. Under this agreement, we must provide the Province with the financial and non-

financial information necessary to allow the Province to periodically inform Ontario's legislature regarding our ongoing performance. This information includes all significant or contentious matters, progress reports concerning compliance with market power mitigation measures, information in respect of all matters requiring shareholder approval and all financial reports. Additionally, the shareholder's agreement requires that we consult with the Province with respect to matters concerning our dividend policy and obtain approval from the Province in advance of any proposal to issue or transfer shares in Hydro One or its subsidiaries, any major transaction, including the sale of assets, which would potentially have a material effect on the financial interest of the Province or our ability to make payments to OEFC or payments in lieu of taxes (proxy taxes) under the *Electricity Act, 1998*.

TRANSFER AGENTS AND REGISTRARS

The trustee and registrar for our company's debt securities is Computershare Investor Services Inc., located in Toronto, Ontario.

The U.S. trustee and registrar for our company's debt securities is Bank of Nova Scotia Trust Company of New York located in New York, New York.

MATERIAL CONTRACTS

Except for the following, since January 1, 2002, our company did not enter into any material contracts, other than contracts in the ordinary course of business:

- (a) (i) a third supplemental trust indenture dated as of January 31, 2003 relating to the issuance of Series 4 Notes in the aggregate principal amount of \$1,000,000,000, of which \$200,000,000 was drawn down on January 31, 2003, \$120,000,000 was drawn down on June 25, 2004 and \$65,000,000 was drawn down on August 24, 2004, pursuant to the Trust Indenture dated as of June 4, 2001 (the "Trust Indenture");
- (ii) a fourth supplemental trust indenture dated as of April 22, 2003 relating to the issuance of Series 5 Notes in the aggregate principal amount of \$1,000,000,000, of which \$250,000,000 was drawn down on April 22, 2003 and \$65,000,000 was drawn down on August 20, 2004, pursuant to the Trust Indenture;
- (iii) a fifth supplemental trust indenture dated as of June 23, 2003 relating to the issuance of Series 6 Notes in the aggregate principal amount of \$1,000,000,000, of which \$500,000,000 was drawn down on June 23, 2003, pursuant to the Trust Indenture;
- (iv) a sixth supplemental trust indenture dated as of February 24, 2004 relating to the issuance of Series 7 Notes in the aggregate principal amount of \$1,000,000,000, of which \$250,000,000 was drawn down on February 24, 2004, pursuant to the Trust Indenture;
- (v) a seventh supplemental indenture dated as of November 15, 2004 relating to the issuance of Series 8 Notes in the aggregate principal amount of

\$1,000,000,000, of which \$40,000,000 was drawn down on November 15, 2004, pursuant to the Trust Indenture;

- (vi) an eighth supplemental indenture dated as of May 19, 2005 relating to the issuance of Series 9 Notes in the aggregate principal amount of \$1,000,000,000 of which \$350,000,000 was drawn down on May 19, 2005, and \$250,000,000 was drawn down on April 24, 2006, pursuant to the Trust Indenture;
- (vii) a ninth supplemental trust indenture dated as of March 3, 2006 relating to the issuance of Series 10 Notes in the aggregate principal amount of \$1,000,000,000 of which \$300,000,000 was drawn down on March 3, 2006 and \$150,000,000 was drawn down on August 22, 2006, pursuant to the Trust Indenture; and
- (viii) a tenth supplemental trust indenture dated as of October 19, 2006 relating to the issuance of Series 11 Notes in the aggregate principal amount of \$1,000,000,000 of which \$75,000,000 was drawn down on October 19, 2006, pursuant to the Trust Indenture.

Each of these supplemental trust indentures supplement the terms of the Trust Indenture which contains customary covenants and representations by our company for the public issuance of debt securities in the Canadian market.

- (b) a Dealer Agreement dated June 24, 2005 between our company and BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. (collectively, the “Dealers”) relating to the public offering of unsecured medium term notes of Hydro One in a maximum aggregate principal amount of up to \$2,500,000,000. The Dealer Agreement provides for the appointment of the Dealers as non-exclusive agents of Hydro One to solicit, from time to time, offers to purchase its medium term notes in Canada and, in certain circumstances, the United States.

Copies of these documents are available on www.sedar.com.

INTERESTS OF EXPERTS

Ernst & Young LLP provides the following services to our company:

- (a) quarterly review of our company’s consolidated financial statements;
- (b) annual audit of our company’s consolidated financial statements;
- (c) annual audit of Hydro One Networks Inc.’s transmission and distribution businesses, Hydro One Remote Communities Inc.’s and Hydro One Brampton Networks Inc.’s financial statements; and

- (d) annual audit of our company's pension fund and the following companies which hold our alternative asset investments: HOPF-HFG Investments Ltd., HOPF – HFM Investments Ltd., HOPF-PEJ Investments Ltd. and HOPF-PEP Investments Ltd.

Ernst & Young LLP is independent in Canada in accordance with its rules of professional conduct.

KPMG LLP has provided services in respect of the documentation, evaluation and enhancement of internal controls over financial reporting and disclosure controls consistent with Multilateral Instrument 52-109.

Mercer Human Resource Consulting LLC provides the following services to our company:

- (a) annual accounting actuarial valuation (valuation report prepared);
- (b) tri-annual funding actuarial valuation (valuation report prepared in 2004); and
- (c) annual accounting actuarial valuation for supplementary pension plan for purposes of letters of credit (valuation report prepared).

ADDITIONAL INFORMATION

Additional Information about Hydro One is available on SEDAR (System for Electronic Document Analysis and Retrieval) at www.sedar.com

As our sole shareholder is the Province, we are not required to prepare an information circular. Additional financial information is contained in our audited comparative consolidated financial statements, together with the auditors' report thereon, and our Management's Discussion and Analysis for our most recently completed fiscal year, each of which may be found on SEDAR at www.sedar.com

STATEMENT OF EXECUTIVE COMPENSATION

Executive Compensation

The following table sets forth the annual compensation for the years ended December 31, 2004 to 2006 for each individual who served or acted as Chief Executive Officer or as a Chief Financial Officer during the most recently completed financial year, and for each of the three most highly compensated executive officers, other than those individuals who served or acted as the Chief Executive Officer and the Chief Financial Officer, at the end of the most recently completed financial year ("Named Executive Officers"). The information provided in the Summary Compensation Table differs from the information published under the *Public Sector Salary Disclosure Act* (Ontario) for the years ended December 31, 2004 to 2006. The differences are due to the timing of payment of incentive awards. Salary disclosures under the *Public Sector Salary Disclosure Act* are limited to amounts listed on T4 forms for each year. Information in the summary compensation table is based on the year the incentive was earned. The incentive is generally earned in one year and paid early in the following year.

Summary Compensation Table

Annual Compensation

	<u>Year</u>	<u>Salary</u>	<u>Bonus</u> ⁽¹⁾	<u>Other Annual Compensation</u>	<u>All Other Compensation</u>	<u>LTIP Payouts</u>
Tom Parkinson	2006	\$761,786	\$648,000	\$139,113 ⁽³⁾	\$3,320,000 ⁽⁶⁾	
President and Chief	2005	\$780,000	\$702,000	\$129,630 ⁽⁴⁾		
Executive Officer ⁽²⁾	2004	\$750,000	\$600,000	\$125,923 ⁽⁵⁾		
Laura Formusa ⁽⁷⁾	2006	\$300,000	\$135,000	(8)		
President and Chief	2005	\$280,000	\$140,000	(8)		\$29,481 ⁽⁹⁾
Executive Officer (Acting)	2004	\$257,352	\$135,000	(8)		\$29,481 ⁽¹⁰⁾
Beth Summers	2006	\$320,000	\$145,000	(8)		
Chief Financial Officer	2005	\$280,000	\$140,000	(8)		\$9,466 ⁽⁹⁾
	2004	\$233,750	\$125,000	(8)		\$9,466 ⁽¹⁰⁾
Myles D'Arcey	2006	\$310,000	\$150,000	(8)		
Senior Vice President,	2005	\$285,000	\$142,500	(8)		\$21,793 ⁽⁹⁾
Customer Operations	2004	\$220,000	\$66,000	(8)		\$21,793 ⁽¹⁰⁾
Tom Goldie	2006	\$300,000	\$135,000	(8)		
Senior Vice President,	2005	\$280,000	\$140,000	(8)		\$51,987 ⁽⁹⁾
Corporate Services	2004	\$268,233	\$135,000	(8)		\$51,987 ⁽¹⁰⁾
Nairn McQueen	2006	\$260,000	\$90,000	(8)		
Vice President,	2005	\$250,000	\$100,000	(8)		\$21,548 ⁽⁹⁾
Engineering and Construction Services	2004	\$200,000	\$80,000	(8)		\$21,548 ⁽¹⁰⁾

- (1) This represents incentives paid under our short term incentive plan.
- (2) Mr. Parkinson was appointed as President and Chief Executive Officer on April 9, 2003, effective as of January 21, 2003. On December 8, 2006, Mr. Parkinson resigned.
- (3) This amount includes an executive allowance of \$37,619 and payment of \$49,215 under the flexible benefits program.
- (4) This amount includes an executive allowance of \$40,000 and payment of \$40,478 under the flexible benefits program.
- (5) This amount includes an executive allowance of \$40,000 and payment of \$41,544 under the flexible benefits program.
- (6) Represents amounts paid, payable or accrued in connection with Mr. Parkinson's resignation effective as of December 8, 2006.
- (7) On December 8, 2006, the Hydro One Inc. Board of Directors appointed Ms. Formusa as President and Chief Executive Officer (Acting). Previously, Ms. Formusa held the position of General Counsel and Secretary.
- (8) Each of Ms. Formusa, Ms. Summers, Mr. D'Arcey, Mr. Goldie and Mr. McQueen is entitled to perquisites and other benefits in an amount that is less than \$50,000 and 10 per cent of the total of his or her annual salary and bonus.
- (9) This amount represents the aggregate of: (i) payment of the third and final instalment relating to the first performance period under our long term incentive plan, which was discontinued effective December 31, 2002, and (ii) payment of the second and final instalment of the second performance period thereunder for each of Ms. Formusa, Ms. Summers, Mr. D'Arcey, Mr. Goldie and Mr. McQueen.
- (10) This amount represents the aggregate of: (i) payment of the second instalment relating to the first performance period under our long term incentive plan, which was discontinued effective December 31, 2002, and (ii) payment of the first instalment of the second performance period thereunder for each of Ms. Formusa, Ms. Summers, Mr. D'Arcey, Mr. Goldie and Mr. McQueen.

Hydro One has established a short-term incentive plan ("Short-Term Incentive Plan") for our executive and managerial employees, as well as separate plans for staff represented by the Power Workers' Union and the Society of Energy Professionals. See "Report on Executive Compensation – Performance Measures and Targets." However, through the collective bargaining process, the plan for Society of Energy Professional members was eliminated effective January 1, 2003, and the plan for members of the Power Workers' Union was eliminated on April 1, 2005.

The Human Resources and Public Policy Committee of our Board of Directors made a number of changes in management compensation during 2002 with respect to base salary, short-term incentive and long term incentive in order to effect cost savings. With respect to long term incentive, our Board of Directors, on the advice of the Committee, decided to discontinue our long-term incentive plan effective December 31, 2002. Any credits which had been earned by employees up until that date have been paid, as we met our financial targets for the performance periods in question. This plan provided for executive and managerial employees to receive notional incentive units in proportion to their base salaries. These units appreciated in value

based on achievement of a performance goal based on cumulative net income over three year performance periods. This plan provided that awards would vest and be paid over a three-year period, provided the employee remained employed by Hydro One, unless otherwise agreed to in individual employment contracts, and provided further that the cumulative three-year net income goal was achieved. There were two performance periods introduced before the plan was discontinued. The first performance period ran from January 1, 2000 to December 31, 2002 and the second performance period ran from January 1, 2001 to December 31, 2003. 100% of the awards were to be paid out for the first performance period and two-thirds of the awards were to be paid out for the second performance period, provided that the employee remained employed by Hydro One. All payments have now been made under the plan. 229 managerial employees received payouts for the third and final instalment of the first performance period and 254 managerial employees received payouts for the second and final instalment of the second performance period. These instalments were paid in 2005.

Benefits payable under Hydro One's registered pension plan are restricted by the *Income Tax Act* (Canada). This limit on benefits affects members whose average annual earnings exceed approximately \$125,000 in 2007. Participants whose pensions would otherwise be restricted by the *Income Tax Act* (Canada) participate in an unregistered supplementary pension plan that provides benefits equal to the difference between the *Income Tax Act* (Canada) maximum pension benefits and the benefits determined in accordance with the formula set out in Hydro One's registered pension plan. The supplementary pension plan is unfunded and the additional retirement income is paid from general revenues. The supplementary pension plan is secured by a letter of credit.

The following table reflects an estimate of total annual lifetime benefits payable under the Hydro One registered pension plan and the unregistered supplementary pension plan. The table as set out below assumes a normal retirement age of 65, and assumes that the maximum pensionable earnings established under the Canada Pension Plan at retirement is equal to the maximum for 2007. Retirement at an earlier age may cause benefits to be subject to an early retirement discount.

Pension Plan Table

<u>Highest average earnings</u>	<u>15 years of Service</u>	<u>20 years of Service</u>	<u>25 years of Service</u>	<u>30 years of Service</u>	<u>35 years of Service</u>
\$200,000	\$55,903	\$74,538	\$93,172	\$111,806	\$130,441
300,000	85,903	114,538	143,172	171,806	200,441
400,000	115,903	154,538	193,172	231,806	270,441
500,000	145,903	194,538	243,172	291,806	340,441
600,000	175,903	234,538	293,172	351,806	410,441
800,000	235,903	314,538	393,172	471,806	550,441
1,000,000	295,903	394,538	493,172	591,806	690,441
1,200,000	355,903	474,538	593,172	711,806	830,441
1,400,000	415,903	554,538	693,172	831,806	970,441
1,600,000	475,903	634,538	793,172	951,806	1,110,441

For each year of credited service under the Hydro One Pension Plan (consisting of the Hydro One registered pension plan and the supplementary pension plan), to a maximum of 35 years, the benefit provided for each of the officers who participate in the plan is equal to 2% of the member's average base annual earnings during the 36 consecutive months (60 consecutive months for management employees hired on or after January 1, 2004 and for employees represented by the Society of Energy Professionals hired on or after November 17, 2005) when his or her base earnings were highest, reduced by 0.625% of the member's average base annual earnings up to the year's maximum pensionable earnings during the 60 consecutive months when his or her base earnings were highest. Base annual earnings are comprised of the member's salary and 50% of his or her short term incentive. Unless altered by contractual agreement, the Hydro One Pension Plan provides for early retirement with an unreduced pension at the earlier of age 65 and the attainment of years of age plus continuous employment totalling 82 or more (85 for management employees hired on or after January 1, 2004 and for employees represented by the Society of Energy Professionals hired on or after November 17, 2005). A plan member who is not eligible for an unreduced pension can retire with a reduced pension any time after attaining age 55. Bridge benefits are provided to all plan members except management employees hired on or after January 1, 2004 and employees represented by the Society of Energy Professionals hired on or after November 17, 2005. Pension increases of 100% of the increase in the Ontario consumer price index (75% for management employees hired on or after January 1, 2004 and for employees represented by the Society of Energy Professionals hired on or after November 17, 2005) will be given on January 1 of each year to pensioners, beneficiaries and terminated employees with deferred pensions. The normal form of pension for a member who does not

have a spouse at retirement is a pension payable for life and guaranteed for five years. The normal form of pension for a member who has a spouse at retirement is a pension payable for the life of the member, and continuing after the member's death to his or her spouse at the rate of $66\frac{2}{3}\%$ of the amount the member was receiving.

Each of the Named Executive Officers participate in the Hydro One Pension Plan. The projected credited years of service that each will have is as follows: Mr. Parkinson- 16.3 at age 65; Ms. Formusa – 35 years at age 65; Ms. Summers - 33.83 years at age 65; Mr. D'Arcey - 35 years at age 65; Mr. Goldie – 35 years at age 65; and Mr. McQueen 15.08 years at age 65.

Each of Mr. Parkinson, Ms. Formusa, Ms. Summers, Mr. Goldie and Mr. McQueen is a party to an employment agreement with Hydro One governing the terms of their employment or former employment with Hydro One, as the case may be. Each of Mr. Parkinson, Ms. Formusa, Ms. Summers, Mr. Goldie and Mr. McQueen was entitled under their respective employment agreements to the salary, benefits and pension entitlements described above. As noted above, on December 8, 2006, Mr. Parkinson resigned as President and Chief Executive Officer and Ms. Formusa was appointed President and Chief Executive Officer (Acting). No changes were made to the terms of Ms. Formusa's employment with Hydro One upon her appointment as President and Chief Executive Officer (Acting). The Board of Directors is expected to review the terms of Ms. Formusa's employment with Hydro One in the coming months.

Pursuant to the terms of Mr. Parkinson's employment agreement, Mr. Parkinson's employment was scheduled to end on January 31, 2010, unless it was extended by the mutual agreement of Mr. Parkinson and Hydro One. Pursuant to the agreement, Mr. Parkinson's base salary increased by 4% in 2005, by 3.85% in 2006 and was to have increased by 4.9% in 2007. If Mr. Parkinson's employment was terminated by Hydro One without cause, Mr. Parkinson was entitled to receive: (i) an amount equal to his base salary and executive allowance for a period of 24 months following the date of his termination (payable either in a lump sum or in equal monthly instalments over such 24-month period); (ii) full benefits for a period of 24 months following the date of his termination (payable either in a lump sum or in equal monthly instalments over such 24-month period); (iii) the payment of a bonus, being an amount that is not less than the greater of the average of the three previous bonus payments or 25% of his base salary (payable either in a lump sum or in equal monthly instalments over such 24-month period); (iv) the continuation of mortgage subsidy payments (discussed below) up to a maximum of \$125,000 and (v) the reimbursement of certain relocation costs if he relocates to Australia. Mr. Parkinson was also entitled to earn credited service under the Hydro One Pension Plan during such period (discussed below). To recognize Mr. Parkinson's relocation to Canada, Hydro One agreed, during the term of his employment agreement and upon termination, to subsidize the monthly interest payable on the mortgage for Mr. Parkinson's home up to an aggregate amount of \$125,000.

In addition, pursuant to Mr. Parkinson's employment agreement, Mr. Parkinson was entitled to receive the benefit of a supplemental retirement benefit, which includes pension and other benefits on the same basis as the Hydro One Pension Plan with certain enhancements. This supplemental retirement benefit provides for an unreduced early retirement pension on termination of employment at or after age 60. All such benefits paid to Mr. Parkinson under the supplemental retirement benefit will be reduced by the benefit payments made to him under the Hydro One Pension Plan when such payments are actually made. All credited service under the Hydro One Pension Plan will also be recognized as credited service under the supplemental retirement benefit plan and Hydro One will credit the supplemental retirement benefit plan for

pension accrual and benefits eligibility purposes, with an additional one-half year of credited service for each year of credited service under the Hydro One Pension Plan (including the 24-month period contemplated above). In certain circumstances, including termination without cause, Mr. Parkinson will be entitled to an additional one-half year of service for each year of credited service under the Hydro One Pension Plan (including the termination period). Upon Mr. Parkinson's death, resignation, retirement or termination, with or without cause, in calculating Mr. Parkinson's benefits under the supplemental retirement benefit plan, the base earnings used in his supplemental pension payment calculations shall be deemed to be increased by \$5,560 per month for the 36 consecutive months when his base earnings were highest.

In connection with his resignation, Mr. Parkinson received or is entitled to receive payment of approximately \$3.3 million in the aggregate comprised of: (i) a lump sum payment in respect of his 2007 base salary and executive allowance for a period of 24 months following the date of his resignation; (ii) full benefits for a period of 24 months following the date of his resignation (payable either in a lump sum or over such 24 month period); (iii) the payment of a bonus, being an amount that is not less than the greater of the average of the three previous bonus payments and 25% of his base salary (payable either in a lump sum or over the 24 month period after his resignation); (iv) the payment of unpaid mortgage subsidy payments payable in connection with Mr. Parkinson's relocation to Canada (payable in a lump sum); and (v) certain relocation costs if Mr. Parkinson relocates to Australia. Hydro One will also credit the supplemental retirement benefit plan, for pension accrual and benefits eligibility purposes, with an additional one year of credited service for each year of credited service under the Hydro One Pension Plan, as described more fully above. Further, in calculating the benefit payable, the base earnings used in his supplemental pension payment calculations shall be deemed to be increased by \$5,560 per month for the 36 consecutive months during which his base earnings were at the highest levels.

Mr. Parkinson has signed customary releases in favour of Hydro One in connection with his resignation and has agreed to keep information concerning Hydro One confidential.

With respect to Ms. Formusa, Ms. Summers, Mr. Goldie and Mr. McQueen, if their employment is terminated by Hydro One without cause, each of Ms. Formusa, Ms. Summers, Mr. Goldie and Mr. McQueen is entitled to receive an amount equal to his or her base salary at the date of termination in equal monthly instalments for a period of 24 months (18 months in the case of Mr. McQueen) and to receive benefits over the same period (including bonus payments equal to the average of the three previous bonus payments). Each of Ms. Formusa, Ms. Summers, Mr. Goldie and Mr. McQueen would continue to earn credited service under the Hydro One Pension Plan during such 24-month period (18-month period in the case of Mr. McQueen).

REPORT ON EXECUTIVE COMPENSATION

Responsibilities of Human Resources and Public Policy Committee

The mandate of the Human Resources & Public Policy Committee (the "Committee") includes reviewing the performance and remuneration of our senior executives, including recommending to the Board of Directors the remuneration of the President. In addition, the Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, and providing advice to the Board of Directors on public affairs issues that have a significant impact on our company. The Committee is comprised of the following directors: Mr. Blake Wallace (Chair), Mr. Walter Murray, Ms.

Kathleen O'Neill (resigned January 24, 2007) and Mr. Murray Elston. The Hon. Bob Rae was appointed Chair of the Committee in 2004 and resigned on April 17, 2006.

General

The compensation of Hydro One's executive officers, including those named in the Summary Compensation Table (the "Named Executive Officers"), is determined by our Board of Directors upon recommendations made by the Committee.

Hydro One's executive compensation program is designed to establish pay levels based on performance and be competitive with Canadian utility and energy companies, both publicly and privately owned. The program is designed to attract, motivate and retain executives, critical for Hydro One's current and long-term success. This is particularly critical considering the risks associated with employee demographics and the competitiveness of the market for skilled energy sector employees. See "Risk Factors – Work Force Demographic Risk."

Approximately 25% of Hydro One's employees will be eligible for retirement by 2008. In some parts of the organization, the risk is much higher. Accordingly, company success will be tied to the ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as the labour market for the industry is expected to be highly competitive in the future. In addition, many Hydro One employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. Hydro One has already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions, to opportunities in other electricity sector positions across Canada (and, in particular, in Ontario) as well as senior positions outside of the sector.

The level of responsibility and the relative importance of positions in Hydro One are evaluated to establish appropriate reference points for internal and external comparison. To provide maximum objectivity, the evaluation of each executive officer position is determined by the Committee based on the advice of independent compensation consultants. See "Independent Advice" in this report below.

Compensation for executive officers consists of a base salary and an opportunity for an annual short-term incentive, all of which are approved by the Committee. The Committee's assessment of compensation is based on a number of quantitative and qualitative factors which include contributions to key corporate strategies and financial results. See "Performance Measures and Targets" in this report below.

Independent Advice

The Committee engages the services of an independent consultant from the Hay Group to provide advice and counsel on compensation matters, including executive compensation.

Performance Measures and Targets

Hydro One establishes its performance measures and targets on an annual basis. The Committee reviews these measures and targets, which are subsequently reviewed and approved by the Board of Directors. These measures and targets are based on Hydro One's key strategic goals in the

areas of safety, customers, reliability, financial and employees. See “Description of the Business – Our Strategy.”

Hydro One develops measures and targets to assess performance in all of the above strategic areas, while ensuring that the needs of key stakeholders are recognized. The Committee determined that Hydro One met or exceeded its targets in all but the Generator Customer satisfaction area in 2006, noting the improvement in a number of areas over 2005.

Safety and Employees

The potentially hazardous nature of Hydro One’s business requires a strong focus on safety. In this area, Hydro One measures the high Maximum Reasonable Potential for Harm (MRPH) incidents rate to identify possible problems or situations that may increase the risk of injury. Hydro One achieved an 8.0 high MRPH rate in 2006, which is 16% lower than 2005 and 38% lower than 2003. Hydro One exceeded its target in 2006.

With respect to serious incidents in high risk areas, Hydro One focuses on electrical contacts, preventable motor vehicle accidents, work equipment failures, asset equipment failures, falling objects and falls to different levels. The number of serious incidents declined from 9.3 incidents per million hours worked in 2003, to 5.2 in 2006. Hydro One exceeded its target in 2006.

Customers

Customer satisfaction is also key to Hydro One. The Large Transmission Customer Satisfaction Survey results showed an improvement from 83% satisfied in 2005 to 86% satisfied in 2006. Hydro One has seen continuous improvement in large customer satisfaction year over year since 2002. The Residential and Small Business Customer survey results increased from 81% satisfaction in 2005 to 83% satisfaction in 2006. While 2006 Generator Customer survey results were satisfactory, they were slightly below target. The Committee found that Hydro One had met or exceeded its targets in all areas of customer satisfaction, with the exception of the Generator Customer satisfaction area.

Reliability

Reliability is influenced by weather patterns and generation constraints, requiring high performance from both the Company’s transmission and distribution systems. Hydro One is conscious that businesses of all sizes require a reliable service to allow them the opportunity to deliver their products and services, and it is with these circumstances in mind that Hydro One’s goal is to achieve top-quartile reliability. In 2006, Hydro One met its annual reliability targets, as well as improved on most of its results from 2005. This achievement is particularly significant bearing in mind that the targets were met while managing the impacts of a number of devastating storms throughout the year, including significant back-to-back storms experienced over the summer. Hydro One’s restoration efforts were recognized by the receipt of an award from the Edison Electric Institute in Washington, D.C. Further, the North American Electric Reliability Council completed a Readiness Audit of the OGCC and gave Hydro One’s transmission operations facilities, processes and staff high marks for their ability to reliably operate and maintain Ontario’s electricity transmission system. See “Description of the Business – Our Transmission Business – NERC Readiness Audit”. The Committee found that Hydro One had met or exceeded its targets in this area.

Financial

Finally, meeting strong financial performance is an integral part of Hydro One's business focus. In 2006, Hydro One maintained or improved credit ratings on both short-term and long-term debt. In June, Hydro One's long-term debt rating was upgraded to "A (high)" by Dominion Bond Rating Services Inc. as a result of key factors, including the expectation that Hydro One's financial profile will remain strong over the medium to long-term. The Committee found that Hydro One had met or exceeded its targets in this area.

Base Salary

The Committee establishes salary ranges for the positions held by executive officers following a review of market data from peer group, industry and national surveys provided by independent consultants. In 2002, the Committee revised the compensation policy in relation to base salary. The peer group used by Hydro One for this purpose consists of Canadian utility and energy companies, both publicly and privately owned. Hydro One's policy for base salaries for executive officers is the 75th percentile of the target market. The actual level of base salary, within the approved range for each executive officer, including the Named Executive Officers, is determined on the basis of job function and the individual's performance and experience.

Short Term Incentive

Hydro One's Short-Term Incentive Plan is a mechanism used by the Company to drive performance. There is a strong correlation between corporate performance and short term incentive payments in Hydro One. Management staff do not receive stock options and the Company no longer provides a long-term incentive. Hydro One's Short-Term Incentive Plan provides an opportunity for participants, including the Named Executive Officers, to earn an annual cash incentive payment based on both the achievement of performance targets set by the Board and on their individual contributions to these targets. Performance is measured by comparing actual results against targets established at the beginning of the year. See "Performance Measures and Targets" in this report above. Potential awards are expressed as a percentage of base salary. For the Named Executive Officers, potential awards range between 0% and 60% of base salary (between 0% and 80% of base salary for the President and Chief Executive Officer) when target performance criteria are met and subject to the discretion of the Committee. The Board of Directors, in its discretion, may provide an award over the maximum for the President and Chief Executive Officer.

Long-Term Incentive

The long-term incentive plan is described above. The plan was discontinued effective December 31, 2002 and the final payouts under the plan were made in 2005.

President and Chief Executive Officer Compensation

The pay-for-performance philosophy of Hydro One's executive compensation program applies equally to the President and Chief Executive Officer. The compensation of the President and Chief Executive Officer is recommended by the Committee and approved by the Board after careful assessment of personal contribution to the performance of Hydro One. This assessment is based on a number of quantitative and qualitative factors which include financial results,

strategic planning and initiatives, personal leadership and business acumen. See “Performance Measures and Targets” in this report above.

Compensation of Directors

The by-laws of Hydro One provide that directors may receive reasonable remuneration for their services, commensurate with their duties, together with reimbursement for all reasonable expenses incurred in fulfilment of their duties, including travel expenses. The amount of such remuneration is determined by the Board of Directors from time to time. The following remuneration is currently paid to directors:

Retainer for directors	\$25,000 per annum
Retainer for Committee Chairs	\$3,000 per annum
Participation in Board and Committee Meetings	\$900 per meeting

The fees are reviewed periodically but have not been revised since 2001. The President and Chief Executive Officer is not entitled to these fees.

Directors’ fees, less statutory deductions, are paid quarterly by direct deposit or cheque as requested.

Rita Burak was appointed as Chair of our Board of Directors on May 30, 2003. Ms. Burak receives annual remuneration of \$150,000 per annum, which was reduced from \$250,000 per annum paid to Board Chairs in the past, and does not receive any additional fees for serving as a director.

The foregoing report has been made by the members of the Human Resources and Public Policy Committee:

Mr. Blake Wallace, Chair

Mr. Murray Elston

Mr. Walter Murray

APPOINTMENT OF AUDITOR

The auditor of our company is Ernst & Young LLP, who was first appointed as auditor on January 18, 1999.

AUDIT AND FINANCE COMMITTEE INFORMATION

The Audit and Finance Committee’s Charter

Our Audit and Finance Committee’s mandate is attached hereto as Appendix “A”, which Appendix is hereby incorporated by reference.

Composition of the Audit and Finance Committee

The current members of our Audit and Finance Committee are Eileen A. Mercier, Murray J. Elston, Walter Murray and Douglas E. Speers. Kathleen O'Neill was a member of the Audit and Finance Committee during 2006 until her resignation effective as of January 24, 2007.

All members are independent and financially literate as such terms are defined under applicable Canadian securities legislation.

Relevant Education and Experience

In addition to each member's general business experience, the education and experience of each Audit and Finance Committee member that is relevant to the performance of his or her responsibilities as an Audit and Finance Committee member is described below.

Mrs. Mercier holds an MBA from York University. Mrs. Mercier formed her own management consulting firm, Finvoy Management Inc., specializing in financial strategy, restructuring and corporate governance issues, in 1995. From 1990 to 1995, Mrs. Mercier served as the Chief Financial Officer of Abitibi-Price Inc. In addition, Mrs. Mercier is a Fellow of the Institute of Canadian Bankers. Since 1994, Mrs. Mercier has served on the audit committees of several boards of directors and is also Chair of the Ontario Teachers' Pension Plan.

Mr. Elston has held various senior positions in the Government of Ontario including Chairman of the Management Board, Chairman of the Public Accounts Committee and Minister of Financial Institutions which involved a regulatory function with respect to financial institutions. Mr. Elston has also served in officer positions of several non-profit companies.

Ms. O'Neill is a Fellow of the Institute of Chartered Accountants. Ms. O'Neill has held various positions with BMO Financial Group and was a Tax Partner with PricewaterhouseCoopers where she provided advice on corporate structuring and international tax issues, as well as audit issues. Ms. O'Neill has served on the audit committees of several boards of directors and was the Chair of the St. Joseph's Health Centre's Audit & Finance Committee.

Mr. Murray is the former Vice-Chairman and member of the Executive Committee of RBC Capital Markets. That role included senior responsibility for relationship cover for a portfolio of major Canadian and international accounts. Since 2000, Mr. Murray has been a director of Ivernia Inc.'s Board of Directors and Chair of its Audit Committee.

Mr. Speers holds an MBA from the Richard Ivey School of Business at the University of Western Ontario. He is currently Chairman and Director of Emco Corporation and has held several senior positions with Imperial Oil Ltd. in Canada and Exxon International. He is a member of the Boards of a number of privately held companies.

Audit and Finance Committee Oversight

There have been no recommendations of our Audit and Finance Committee to nominate or compensate an external auditor which have not been adopted by our board of directors.

Pre-Approval Policies and Procedures

In accordance with the provisions of its mandate, the Audit and Finance Committee ratifies all non-audit services, as pre-approved by the Committee Chair, to be provided to the Corporation by its external auditor.

External Auditor Service Fees

(a) *Audit Fees*

The audit fees to be billed by Ernst & Young LLP for fiscal 2006 are estimated to be \$895,000. The audit fees billed by Ernst & Young LLP for fiscal 2005 were \$599,100.

(b) *Audit-Related Fees*

The total audit-related fees billed by Ernst & Young LLP for fiscal 2006 were \$169,900. The nature of the services rendered were: accounting and internal control consultations, audit of the Hydro One Pension Plan, French translations and executive expense review.

The audit-related fees billed by Ernst & Young LLP for fiscal 2005 were \$145,400. The nature of the services rendered were: accounting and internal control consultations, audit of the Hydro One Pension Plan, French translation and executive expense review.

(c) *Tax Fees*

No tax fees were billed by Ernst & Young LLP for fiscal 2006.

The tax fees billed by Ernst & Young LLP for fiscal 2005 were \$1,200. The nature of the service rendered was: general tax advice.

(d) *All Other Fees*

There were no other fees billed by Ernst & Young LLP which are applicable for fiscal 2006 or fiscal 2005.

CORPORATE GOVERNANCE DISCLOSURE

Board of Directors

The Board has undertaken an independence assessment and determined that all of Hydro One's current directors are "independent" within the meaning of the rules adopted by the Canadian Securities Administrators (the "CSA"). Mr. Tom Parkinson, who was the President and Chief Executive Officer of our company and a member of Board of Directors until December 8, 2006, was not independent.

The Board has separated the roles of Chair and Chief Executive Officer. Ms. Rita Burak was appointed Chair of the Board on May 30, 2003 and is an independent director. The prime

responsibility of the Chair of the Board of Directors is to provide leadership to the Board and to enhance Board effectiveness. The Chair, as the presiding member of the Board, also ensures that the relationships between the Board, management, the shareholder and other stakeholders are effective, efficient and further the best interests of our company.

Independent directors hold regularly scheduled meetings at which non-independent directors and members of management are not in attendance. During 2006, seven such sessions without management were held. As well, the Audit and Finance Committee regularly holds such sessions with the external auditors and with the internal auditor. The Chair of the Audit and Finance Committee meets twice a year with the internal auditor. These sessions encourage open and candid discussion among the independent directors.

Summary of Attendance of Directors

The following table summarises the attendance of individual directors at meetings of the Board of Directors held for the 12-month period ending December 31, 2006.

Director	Board Meetings Attended
Rita Burak	15 of 15
Sami Bébawi	12 of 15
Murray J. Elston	13 of 15
Don MacKinnon ¹	13 of 14
Eileen A. Mercier	13 of 15
Walter Murray	15 of 15
Kathleen O'Neill	15 of 15
Tom Parkinson ²	14 of 14
Hon. Bob Rae ³	2 of 3
Kenneth D. Taylor	13 of 15
Douglas E. Speers	15 of 15
Blake Wallace	15 of 15

(1) Mr. MacKinnon was not in attendance at one Board Meeting because this meeting solely addressed labour relations matters and, as President of the Power Workers' Union, there was a conflict of interest.

(2) Mr. Parkinson was a member of the Board until December 8, 2006.

(3) Hon. Bob Rae was a member of the Board until April 17, 2006.

Directors' Board Memberships in Other Reporting Issuers

Director	Reporting Issuer
Rita Burak	University Health Network

Eileen A. Mercier

CGI Group Inc., ING Canada Inc., Shermag Inc., Teekay Shipping Corporation, University Health Network

Walter Murray

Ivernia Inc.

Kathleen O'Neill

MDS Inc., TSX Group Inc.

Kenneth D. Taylor

Devine Entertainment Corp., Ascendia Brands Inc.

Board Mandate

The Board of Directors is responsible for the stewardship of our company and the supervision of management of the business and affairs of our company. The Board's accountabilities and responsibilities include development of our company's approach to corporate governance, the adoption of a strategic plan and the identification of the principal risks of our company's business. The Board has adopted a Mandate, the text of which is set out as Appendix "B", which Appendix is hereby incorporated by reference.

Position Descriptions

The Board has adopted formal position descriptions for the Chair of the Board and the Board Committee Chairs. The position descriptions of each Committee Chair are set out in the Committees' mandates. In general, Committee Chairs are responsible for the leadership of their Committee as well as reporting to the Board on behalf of the Committee. The Board of Directors has also adopted a position description for the President and Chief Executive Officer, which sets out the key roles and responsibilities for that position.

Committees of the Board of Directors

The Board of Directors has established five standing committees of the Board and one ad hoc advisory committee of the Board and delegates certain of its enumerated responsibilities to each of the Committees. Notwithstanding this delegation, the Board retains its oversight function and ultimate responsibility for all matters delegated to committees.

The five standing committees of the Board are the Audit and Finance Committee, the Corporate Governance Committee, the Human Resources and Public Policy Committee, the Regulatory and Environment Committee and the Health and Safety Committee. The ad hoc advisory committee of the Board is the Information Technology Committee. The roles and responsibilities of each Committee are set out in formal written Mandates. These Mandates are reviewed at least annually to ensure that they reflect best practices as well as applicable regulatory requirements. A brief summary of each of the Committees' responsibilities follows.

Audit and Finance Committee

The Audit and Finance Committee is composed entirely of independent directors as required by the CSA rules (for more information, see the mandate of the Audit and Finance Committee which is attached). The Audit and Finance Committee oversees the integrity of accounting

policies and financial reporting, internal controls, internal audit, significant corporate risk exposures, financial compliance and ethics policies.

Corporate Governance Committee

The Corporate Governance Committee is composed entirely of independent directors. The Committee acts as the nominating Committee of the Board of Directors and recommends director candidates, committee assignments, director compensation, and corporate governance policy for committees and the board as a whole. The Committee reviews the general and specific criteria applicable to candidates to be considered for nomination to the Board. The objective of this review is to maintain the composition of the Board in a way that provides the best mix of skills and experience to guide the long-term strategy and ongoing business operations of our company. In addition, the Committee leads an annual evaluation of the Board and makes recommendations on modifications of the evaluation process.

Human Resources and Public Policy Committee

The Human Resources and Public Policy Committee is composed entirely of independent directors. The Committee recommends compensation policy for senior managers, leads the performance review of the Chief Executive Officer, recommends bargaining strategy with respect to the unions, and advises the Board on public policy matters and corporate social responsibility issues. In this regard, the Committee also reviews succession planning and the recommendations for the appointment of persons to senior executive positions. In 2005, Hay Management Consultants were retained to review and provide advice on management compensation. For additional information relating to the compensation of our company's senior executives, see "Statement of Executive Compensation."

Regulatory and Environment Committee

The Regulatory and Environment Committee monitors our company's compliance with regulatory and environmental requirements and related risk, reviews related policies and generally oversees processes and procedures related to regulatory and environmental compliance at our company.

Health and Safety Committee

The Health and Safety Committee advises the Board on health and safety policies and standards, oversees compliance with health and safety regulations at our company, and reviews and reports to the Board on our company's emergency preparedness.

Information Technology Committee

The Information Technology Committee is composed entirely of independent directors and was established as an ad hoc advisory Committee of the Board specifically to assist the Board in its oversight responsibility on matters related to our company's Enterprise Application Systems Replacement Strategy.

The Enterprise Application Systems Replacement Strategy is a strategy to replace our existing customized business applications with commercially available software system applications to

simplify our information technology infrastructure and improve the functionality of our business processes.

Orientation and Continuing Education

Upon joining the Board, all new directors are given a Directors Guide to provide them with an overview of the key organizational, financial, regulatory, and operational aspects of our company. The Directors Guide also contains information on the structure of the Board and its committees, committee mandates and general information on a director's obligations. In addition, new directors receive a tour of our companies' facilities and briefing sessions with senior management. Orientation sessions with senior management and facility tours provide directors with a thorough understanding of our company's business to assist them in the performance of their legal obligations and duties as directors.

On an on-going basis, as part of regular Board meetings, directors receive presentations and reports on topics related to our company's business. These information items are either suggested by management or may be requested by members of the Board. As well, directors receive information from management in response to any actions arising at a board meeting or otherwise.

Ethical Business Conduct

The Board has adopted a written Code of Business Conduct ("Code"). The Code sets out a comprehensive set of principles and expectations relating to ethical conduct, conflicts of interest and compliance with laws. The Code is part of Hydro One's internal control framework and applies to all of Hydro One's directors, officers and employees. The Code also applies to Hydro One's agents, consultants, contractors and business partners, to the extent feasible. The Code is posted on the corporate intranet site and on the external corporate website at www.HydroOne.com.

Our company has a Corporate Ethics Officer who is accountable for making sure that the appropriate actions are taken to investigate and resolve known or suspected violations of the Code, and for ensuring the tracking and reporting of all violations. The Board monitors compliance with the Code through the Human Resources and Public Policy Committee and the Audit and Finance Committee, to whom the Corporate Ethics Officer reports. The Chief Executive Officer is ultimately responsible for our company's compliance with the Code. Further, the Board of Directors abides by a conflict of interest policy which requires directors to exercise independent judgment when considering transactions and contracts in respect of which a director has a material interest.

Board, Committee and Director Assessments

A process is in place for evaluating the effectiveness of the Board of Directors and its Committees. The process consists of two written questionnaires that are completed annually by each Director. The Board Effectiveness Self-Assessment Survey addresses the areas of board responsibility, operation and effectiveness. The Individual Director Self-Evaluation Questionnaire allows each Director to identify areas for improved development and performance. The Directors' responses to the questionnaires are compiled into two summary reports that are reviewed by the Corporate Governance Committee to determine any actions that may need to be taken. The Chair of the Corporate Governance Committee provides a report on the summary

reports to the Board. In addition to the written questionnaires, the Chair of the Board also meets annually with each director about individual performance and the effectiveness of the Board.

**APPENDIX “A”
AUDIT AND FINANCE COMMITTEE MANDATE**

1. Pursuant to By-Law No. 1 of Hydro One Inc. (the “Corporation”), a committee of the directors to be known as the “Audit and Finance Committee” (hereinafter referred to as the “Committee”) is hereby established.
2. The Committee shall be composed of a minimum of four directors, and have membership attributes consistent with applicable requirements under the *Securities Act* (Ontario) and regulations thereunder including:
 - Independence. The Committee shall be comprised of directors who shall meet the independence and audit committee composition requirements set forth by applicable securities regulatory authorities, or any governmental or regulatory body exercising authority over the Corporation, as in effect from time to time. A member cannot accept consulting, advisory or compensatory fees, other than compensation for directors’ fees and expenses, from the Corporation.
 - Financial Literacy. All members are to be financially literate (or shall become financially literate within a reasonable period of time after appointment to the Committee). A member is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation’s financial statements.
3. The members of the Committee shall be appointed or re-appointed at the Organizational Meeting of the Board of Directors (the “Board”) immediately following each annual meeting of the Shareholder of the Corporation. Each member of the Committee shall continue to be a member thereof until his or her successor is appointed, unless such member shall resign or be removed by the Board or shall cease to be a director of the Corporation. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board and shall be filled by the Board if the membership of the Committee is less than four directors as a result of the vacancy. Whenever there is a vacancy on the Committee, the remaining members may exercise all of the powers of the Committee as long as a quorum remains in office.
4. The Board or, in the event of its failure to do so, the members of the Committee, shall appoint a Chair from amongst their number. If the Chair of the Committee is not present at any meeting of the Committee, the Chair of the meeting shall be chosen by the Committee from among the members present. The Committee Chair shall be responsible for the leadership of the Committee, including the preparation of the agenda, presiding over meetings and determining Committee assignments. The Chair presiding at any meeting of the Committee shall have a casting vote in case of deadlock. The Committee shall also appoint a Secretary who need not be a director.
5. The time and place of meetings of the Committee and the procedure at such meetings shall be determined from time to time by the members thereof provided that:

- (a) a quorum for meetings shall be three members, present in person or by telephone or other telecommunication device that permit all persons participating in the meeting to speak and hear each other;
 - (b) the Committee shall meet at least quarterly; and
 - (c) notice of the time and place of every meeting shall be given in writing or facsimile communication to each member of the Committee, the internal auditors and the external auditors of the Corporation at least 24 hours prior to the time fixed for such meeting, provided, however, that a member may in any manner waive a notice of a meeting; and attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called. The Committee may request the external auditors to attend a meeting or meetings of the Committee, the expense of which shall be paid by the Corporation and included within the external auditors' annual fee. A meeting of the Committee may be called by the Secretary of the Committee on the direction of the Chair or Chief Executive Officer of the Corporation, by any member of the Committee, the external auditors or internal auditors. Notwithstanding the provisions of this paragraph, the Committee shall at all times have the right to determine who shall and shall not be present at any part of the meeting of the Committee.
6. The Committee Chair is responsible for reporting to the Board on behalf of the Committee on matters considered by the Committee, its activities and compliance with this mandate.
7. For purposes of this Section, the term "Corporation" shall include Hydro One Inc. and its subsidiary entities, as defined by Multilateral Instrument 52-110 Audit Committees.

The Committee shall:

- (1) in connection with its advisory functions:
 - (a) review the internal audit procedures of the Corporation and advise the Board on its auditing practices and procedures and obtain adequate assurance that internal controls are adequate;
 - (b) meet separately with the external auditors and internal auditors and report to the Board on such meeting;
 - (c) review the recommendations of the officers of the Corporation as to the reappointment or appointment of external auditors and make recommendations to the Board with respect to the nomination and remuneration of external auditors to be appointed at each annual meeting of the Shareholder. If a change in external auditors is proposed, the Committee will inquire as to the reasons for the change, including the response of the incumbent auditors, and inquire as to the qualifications of

the newly proposed auditors before making its recommendation to the Board;

- (d) review periodically, reports on the nature and extent of compliance with requirements regarding statutory deductions and remittances, including deductions and remittances under the *Income Tax Act* (Canada), the *Excise Tax Act* (Canada) and the *Unemployment Insurance Act* (Canada), the nature and extent of non-compliance together with the reasons therefore and the plan and timetable to correct deficiencies and report to the Board on the status of such matters;
- (e) review and reassess the Committee's mandate at least annually and report to the Board results of the review, including any recommended changes to the mandate;
- (f) the Committee shall meet with management to review and assess the process and systems in place for the review of public disclosure documents that contain audited and unaudited financial information and their effectiveness;
- (g) describe in the annual information form all information about the Committee as required by applicable securities regulatory authorities; and
- (h) review and assess with management and recommend to the Board for approval any material transaction, contract or other matter involving the Corporation and a shareholder, or other person, which owns directly or indirectly voting securities of the Corporation. For this purpose, "material" means any transaction, contract or matter that significantly affects, or would reasonably be expected to have a significant effect on, the financial position of the Corporation or the market price or value of its securities.

(2) In connection with the exercise of its powers:

- (a) review and recommend to the Board for approval:
 - (i) the audited annual financial statements of the Corporation, the annual management discussion and analysis ("MD&A") and any required annual MD&A supplement and related press releases before the Corporation publicly discloses this information;
 - (ii) the Corporation's interim (quarterly) financial statements, interim MD&A and any required interim MD&A supplement and related press releases before the Corporation publicly discloses this information, unless the Board delegates to the Committee such approval authority as provided in paragraph (b) below;

- (iii) all financial statements in prospectuses and other offering memoranda, and financial statements required by securities regulatory authorities;
 - (iv) the annual information form of the Corporation and any other similar disclosure required to be filed by securities regulatory authorities;
 - (v) any prospectus, offering memorandum of the Corporation, or any amendments thereto. For the purpose of this mandate, reference to “prospectus” includes a preliminary prospectus, a prospectus, or an amendment thereto, but excludes a pricing supplement; and
 - (vi) the annual financing plans and objectives of the Corporation including, foreign currency risk and interest rate risk strategies.
- (b) subject to the authority delegated by the Board, review and approve the Corporation’s interim financial statements, interim MD&A and any interim MD&A supplement, and review and approve the related press releases;
 - (c) discuss with the external auditors results of their review of the interim financial statements and interim MD&A, including any matters external auditors may raise with audit committees under generally accepted accounting principles and auditing standards in compliance with applicable securities laws and regulations;
 - (d) review the issuance under a shelf prospectus of the Corporation of debentures, notes and/or other unsecured and secured evidences of indebtedness of the Corporation, in accordance with the authority delegated by the Board and the filing with securities regulatory authorities of any prospectus supplement relating thereto;
 - (e) review and oversee the audit plans of the internal auditors and review, pre-approve and directly be responsible for overseeing the work of the external auditors of the Corporation engaged for the purpose of preparing or issuing an auditor’s report or performing other audit, review or attest services for the Corporation, including the resolution of any disagreements between management and the external auditors regarding financial reporting. The Committee has the authority to communicate directly with the internal and external auditors.

The Committee shall also review the degree of co-ordination between the audit plans of the internal auditors and the external auditors and will inquire as to the extent the planned audit scope can be relied upon to detect weaknesses in internal control, fraud or other illegal acts. Any significant recommendations made by the auditors for the strengthening of internal controls will be reviewed;

- (f) pre-approve all audit and non-audit services to be provided to the Corporation by its external auditors. In connection with non-audit services, the Committee shall adopt specific policies and procedures for the engagement of non-audit services ensuring that the non-audit service is not prohibited or restricted by securities regulatory authorities. The Committee may also delegate to one or more of its members the authority to pre-approve audit and non-audit services, in which event the pre-approval of audit and non-audit services by any such member must be presented to and ratified by the Committee at its first scheduled meeting following such pre-approval;
- (g) review the internal control procedures and management's annual internal control report to ensure compliance with the law and avoidance of conflicts of interest including, without limitation, a review of policies and practices concerning officers' expenses and perquisites, including the use of the Corporation's assets;
- (h) review the duties and responsibilities of internal audit staff respecting controls, procedures and accounting practices of the Corporation;
- (i) review management programs and policies regarding the adequacy and effectiveness of internal controls over the accounting and financial reporting systems within the Corporation and, in particular, the Committee will review management's response to the internal control recommendations of the internal and external auditors;
- (j) receive and review regular reports from the internal and external auditors on the appropriateness of the Corporation's significant accounting and disclosure policies and practices and changes thereto, including any areas of management judgement and estimates that have a material effect upon the financial statements, alternative accounting treatments and their ramifications, disagreements between management and the internal and external auditors and include in the review a discussion with the external auditors of the quality, not just acceptability, of accounting principles, the reasonableness of significant judgements, and the clarity and completeness of disclosure;
- (k) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation, and the manner in which these matters have been disclosed in the financial statements;
- (l) review, at least annually, the Corporation's corporate insurance program;
- (m) annually discuss with external auditors and report to the Board the auditors' independence from management and the Corporation, and in connection, request their written confirmation of independence and disclosure of relationships they have with the Corporation that may be

thought to bear on independence, including non-audit related services and fees and their impact;

- (n) review the minutes of any audit committee meetings of subsidiary entities of the Corporation and any significant issues and auditor recommendations concerning such subsidiary entities;
 - (o) review the basis and amount of the external auditor's fees in light of the number and nature of reports issued by the auditors, the quality of the internal controls, the size, complexity and financial condition of the Corporation and the extent of internal audit and other support provided by the Corporation to the external auditors and review all other non-audit fees of the auditors or other accounting firms;
 - (p) review management's retention of consulting and professional services, including external legal services, on an annual basis;
 - (q) review and appropriately address any complaints regarding accounting, internal accounting controls, or auditing matters received since the Committee's last meeting, including complaints confidentially submitted by those wishing to remain anonymous; and
 - (r) receive and review any reports of evidence of a material violation of securities laws or breaches of fiduciary duty tabled by the Corporation's legal counsel as a result of an inappropriate response from management.
- (3) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the current and former external auditor of the Corporation.
- (4) review, at least on an annual basis:
- (a) for information purposes:
 - (i) the major risks to the Corporation's business objectives;
 - (ii) overall financing of risk, including the purchase of insurance;
 - (iii) the risk retention philosophy and risk tolerance guidelines; and
 - (iv) loss prevention policies and risk management programs;
 - (b) for approval by the Committee, the Corporation's enterprise risk management policy and framework;
 - (c) and recommend to the Board for approval all risk management strategies, including foreign currency and interest rate risk strategies.
- (5) With respect to the Hydro One Pension Plan and any replacement plan thereof, review the funding policy, the audited annual financial statements, periodic

reports detailing the asset mix status and performance of the pension fund and any further pension-related reports or policies to be submitted to the Board, including those resulting from the Terms of Reference of the Pension Committee, the Pension Plan Terms of Reference of the Board of Directors, or the Terms of Reference of the Pension Investments Unit.

8. In instances where members of the Committee believe that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of independent counsel and other expert advisers, the Committee shall have authority to engage and compensate the appropriate experts. The Board shall be kept apprised of both the selection of the experts and the expert's findings through the Committee's regular reports to the Board.

**APPENDIX “B”
HYDRO ONE INC.
BOARD OF DIRECTORS
MANDATE**

DUTIES OF THE BOARD OF DIRECTORS

1. The Board of Directors of Hydro One Inc. (the “Board”) is responsible for the stewardship of, and has the duty to supervise the management of, the business and affairs of the Corporation including its Subsidiaries, as defined in the *Business Corporations Act* (Ontario).
2. The Board is elected by the sole Shareholder, the Province of Ontario, as represented by the Minister of Energy (the “Shareholder”). The Board is responsible for seeking and recommending suitable Board candidates to the Shareholder.

ACCOUNTABILITIES AND RESPONSIBILITIES

The Board shall have the accountabilities and responsibilities set out below. In addition, the Board shall perform such duties as may be required under, and act in accordance with the *Business Corporations Act* (Ontario), the Corporation’s by-laws, the Agreement with the Shareholder, dated October 6, 1999 (the “Shareholder Agreement”), as may be amended from time to time, and all applicable laws.

1. Corporate Governance

- (a) The Board is responsible for developing the Corporation’s approach to corporate governance, including developing appropriate policies and procedures and delegating such other matters as it sees fit to the Corporate Governance Committee for its review and consideration.
- (b) The Board is responsible for the Corporation’s approach to its governance relationship with its sole Shareholder.

2. Strategic Planning

The Board is responsible for:

- (a) adopting a strategic planning process and approving, on at least an annual basis, a strategic plan which lays out the strategic direction of the Corporation in the context of the opportunities and risks of the business and the business and commercial environment in which it operates;
- (b) reviewing and approving the business, financial, strategic and other plans proposed by management to enable the Corporation to execute its strategy;
- (c) adopting processes for monitoring the Corporation’s progress toward its strategic and operational goals, and to revising and altering its directions to management in light of changing circumstances affecting the Corporation;

- (d) taking action when corporate performance falls short of its performance targets or other special circumstances warrant;
- (e) approving the audited financial statements, interim financial statements and the notes and management's discussion and analysis accompanying such financial statements and the Corporation's Annual Information Form; and
- (f) reviewing and approving material transactions outside the ordinary course of business, subject to the Shareholder Agreement.

3. **Risk Management**

The Board is responsible for:

- (a) identifying the principal risks of the Corporation's business and ensuring the implementation of appropriate systems to effectively monitor and manage such risks with a view to the long-term viability of the Corporation;
- (b) overseeing the integrity of the Corporation's internal control and management information systems;
- (c) approving, and monitoring compliance with, all significant policies and procedures by which the Corporation is operated; and
- (d) approving policies and procedures designed to ensure that the Corporation operates at all times within applicable laws and regulations.

4. **Human Resources Management**

- (a) The Board is responsible for approving the appointment of the President and CEO. The Board is also responsible for approving the compensation of the President and CEO following a review of the recommendations of the Human Resources and Public Policy Committee.
- (b) The Board will, to the extent feasible, satisfy itself as to the integrity of the President and CEO and other executive officers, and that the President and CEO and other executive officers create a culture of integrity throughout the organization.
- (c) The Board is responsible for ensuring that succession planning programs are in place, including programs to train, develop, monitor and retain senior management, including the President and CEO.

5. **Communications and Reporting**

- (a) The Board is responsible for approving and revising from time to time, a disclosure policy to address accurate and timely communications with the Shareholder, bondholders, employees, financial analysts, governments and regulatory authorities, the media and the public.

- (b) The Board is responsible for overseeing the Corporation's reporting to the Shareholder, responses to requests for information and other reporting obligations as set out in the Shareholder Agreement, and for ensuring open and transparent communication with the Shareholder.

6. Board Meetings and Materials

- (a) The Chair, in consultation with the President and CEO and the General Counsel and Secretary, shall develop the agenda for each Board meeting.
- (b) Meeting materials shall be provided to directors before each Board meeting in sufficient time to ensure adequate opportunity for review.
- (c) Independent directors (as defined under applicable securities legislation) shall hold regularly scheduled meetings at which non-independent directors including members of management are not present.

7. Committees of the Board

- (a) The Board discharges its responsibilities both directly and through its committees: the Audit and Finance Committee, the Corporate Governance Committee, the Human Resources and Public Policy Committee, the Health and Safety Committee and the Regulatory and Environment Committee. In addition to these standing Committees, the Board may from time to time appoint ad hoc Committees to address certain issues of a more short-term nature.
- (b) The Board is responsible for approving the mandates for each Board Committee.
- (c) To facilitate communication between the Board and each Board Committee, each Committee Chair is responsible for providing a report to the Board on material matters considered by the Committee at the first Board meeting after the Committee's meeting.

DIRECTOR DEVELOPMENT AND EVALUATION

- 1. Each new director shall participate in Hydro One's Director Education Program and any continuing director development programs.
- 2. Annually, with the assistance of the Corporate Governance Committee, the Board shall evaluate and review the performance of the Board, each of its Committees, each of the directors and the adequacy of this mandate.

SECTION – 2.1.4

**Terrace Bay Superior Wires Inc.
2007 Rate Schedule**

Terrace Bay Superior Wires Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

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

EB-2007-0579

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES - May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate 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. All customers are single-phase.

General Service Less Than 50 kW

This classification applies to a non residential 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.

General Service 50 to 4,999 kW

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 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, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Terrace Bay Superior Wires Inc.

TARIFF OF RATES AND CHARGES

Effective May 1, 2007

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

EB-2007-0579

MONTHLY RATES AND CHARGES

Residential

Service Charge	\$	20.81
Distribution Volumetric Rate	\$/kWh	0.0145
Regulatory Asset Recovery	\$/kWh	0.0097
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0051
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0046
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	\$	41.34
Distribution Volumetric Rate	\$/kWh	0.0118
Regulatory Asset Recovery	\$/kWh	0.0082
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0041
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	\$	293.24
Distribution Volumetric Rate	\$/kW	4.0020
Regulatory Asset Recovery	\$/kW	2.2726
Retail Transmission Rate – Network Service Rate	\$/kW	1.9115
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.6323
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 connection)	\$	20.53
Distribution Volumetric Rate	\$/kWh	0.0129
Regulatory Asset Recovery	\$/kWh	0.0082
Retail Transmission Rate – Network Service Rate	\$/kWh	0.0047
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kWh	0.0041
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)	\$	1.36
Distribution Volumetric Rate	\$/kW	4.2190
Regulatory Asset Recovery	\$/kW	2.9480
Retail Transmission Rate – Network Service Rate	\$/kW	1.4416
Retail Transmission Rate – Line and Transformation Connection Service Rate	\$/kW	1.2619
Wholesale Market Service Rate	\$/kWh	0.0052
Rural Rate Protection Charge	\$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	\$	0.25

Terrace Bay Superior Wires Inc.

TARIFF OF RATES AND CHARGES

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EB-2007-0579

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
Income tax letter	\$	15.00
Notification Charge	\$	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
Legal letter charge	\$	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
Collection of account charge – no disconnection – after regular hours	\$	165.00
Disconnect/Reconnect at meter – during regular hours	\$	65.00
Disconnect/Reconnect at meter – after regular hours	\$	185.00
Disconnect/Reconnect at pole – during regular hours	\$	185.00
Disconnect/Reconnect at pole – after regular hours	\$	415.00
Install / remove load control device – during regular hours	\$	65.00
Install / remove load control device – after regular hours	\$	185.00
Service call – customer-owned equipment	\$	30.00
Service call – after regular hours	\$	165.00
Temporary service install and remove – overhead – no transformer	\$	500.00
Temporary service install and remove – underground – no transformer	\$	300.00
Temporary service install and remove – overhead – with transformer	\$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	\$	22.35
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	1.0426
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0321
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

SECTION – 2.4.1

Copy of Resolution of the Township of Terrace Bay



THE CORPORATION OF THE TOWNSHIP OF TERRACE BAY

☐ TOWNSHIP OFFICE
31 Simcoe Plaza
P.O. Box 40
Terrace Bay, Ontario
P0T 2W0
Tel: (807) 825-3315
Fax: (807) 825-9576

☐ PUBLIC WORKS
P.O. Box 40
Terrace Bay, Ontario
P0T 2W0
Tel: (807) 825-9016
Fax: (807) 825-9576

☐ RECREATION
DEPARTMENT
P.O. Box 460
Terrace Bay, Ontario
P0T 2W0
Tel: (807) 825-9042
Fax: (807) 825-9608

☐ TOURIST
INFORMATION CENTRE
P.O. Box 1207
Terrace Bay, Ontario
P0T 2W0
Tel: (807) 825-9721
Fax: (807) 825-9420

☐ FIRE DEPARTMENT
Radisson Avenue
P.O. Box 430
Terrace Bay, Ontario
P0T 2W0
Tel: (807) 825-3554
Fax: (807) 825-9576

☐ PUBLIC LIBRARY
P.O. Box 369
Terrace Bay, Ontario
P0T 2W0
Tel: (807) 825-3819
Fax: (807) 825-1249

March 27, 2007

Mr. W. E. Meeker
Hydro One Networks Inc.
483 Bay Street
North Tower, 14th Flr.
Toronto, ON
M5G 2P5

Dear Mr. Meeker:

At their regular meeting on Monday, March 26, 2007 Council received the proposed agreement for the sale of Terrace Bay Superior Wires Inc. After discussion, the following resolution was passed.

"Resolution CR 124-2007

RESOLVED THAT Council accept the initial offer from Hydro One Networks Inc. for the purchase of the distribution facilities and certain land rights and other assets of Terrace Bay Superior Wires Inc., as set out in the Offer to Purchase, final price to be subject to adjustment between Hydro One Networks Inc. and the Township of Terrace Bay.

CARRIED"

If you have any questions regarding the above, please do not hesitate to contact me.

Yours sincerely,

THE CORPORATION OF THE
TOWNSHIP OF TERRACE BAY


Richard J. Beare, AMCT
Chief Administrative Officer/Clerk



The Gem of the North Shore

www.terrace-bay.com