



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	-

(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 conjunct 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., Wimpak 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</u> ⁽¹⁾	<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 Executive Officer ⁽²⁾	2004	\$750,000	\$600,000	\$125,923 ⁽⁴⁾		
	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, Customer Operations	2004	\$220,000	\$66,000		⁽⁶⁾	\$21,793 ⁽⁸⁾
	2003	\$200,000	\$50,000		⁽⁶⁾	\$10,717 ⁽⁹⁾
Laura Formusa	2005	\$280,000	\$140,000		⁽⁶⁾	\$29,481 ⁽⁷⁾
General Counsel and Secretary	2004	\$257,352	\$135,000		⁽⁶⁾	\$29,481 ⁽⁸⁾
	2003	\$246,167	\$125,000		⁽⁶⁾	\$14,926 ⁽⁹⁾
Tom Goldie	2005	\$280,000	\$140,000		⁽⁶⁾	\$51,987 ⁽⁷⁾
Senior Vice President, Corporate Services	2004	\$268,233	\$135,000		⁽⁶⁾	\$51,987 ⁽⁸⁾
	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. Formusa – 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. Formusa 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, Winpak 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.