



**RENEWAL ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2003**

FEBRUARY 16, 2004

HYDRO ONE INC.
ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2003

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Except where otherwise indicated, all information presented herein is as at December 31, 2003.

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;

“**IMO**” refers to 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 is located at 483 Bay Street, 10th Floor, 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.

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 spot market administered by the IMO. 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.

On April 30, 2002, we sold certain assets of our business previously conducted by Ontario Hydro Energy Inc. to Union Energy Inc., a wholly-owned subsidiary of EPCOR Utilities Inc., pursuant to an asset purchase agreement. With the sale of these assets, we are no longer engaged in the competitive retail sale of energy and related services.

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.

On December 9, 2002, the *Electricity Pricing, Conservation and Supply Act, 2002* received Royal Assent and substantially all of its provisions were proclaimed into force. This Act fixed the commodity price for electricity for low volume and designated customers at 4.3 cents per kWh, or such lower price as may be determined by regulation, retroactive to May 1, 2002. In addition, the Act capped transmission and distribution rates at the levels in effect on November 11, 2002 (such rates were originally planned to be in effect until at least April 30, 2006). Furthermore, regulations under this Act fixed the price paid by distributors to the IMO for wholesale market charges other than energy at 0.62 cents per kWh. The Act also effectively capped distribution rates for our customers in remote communities and Brampton.

In addition to the amending legislation referred to above, on December 18, 2003, the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* received Royal Assent and will come into force upon proclamation. The Province has announced that it will file a regulation before April 1, 2004 to bring into force those provisions which implement the Province's interim pricing plan. Under these provisions, effective April 1, 2004, the commodity price for the first 750 kWh of electricity consumption per month by low volume and designated customers will be 4.7 cents per kWh and consumption in excess of that amount will be fixed at a rate of 5.5 cents per kWh. Revenue in excess of a distributor's cost of power will be rebated and shortfalls will be funded by Ontario Electricity Financial Corporation. With respect to electricity used on or after May 1, 2005, or an earlier date prescribed by regulation, the commodity price to be paid by these customers will be determined by the OEB under a process to be developed. The *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* will also amend the *Ontario Energy Board Act, 1998* such that Ministerial approval will no longer be required in respect of applications relating to transmission rates. Approval of the Minister of Energy will still be required in respect of applications relating to distribution rates. On November 25, 2003, the Province announced, in conjunction with the introduction of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, that distributors could start recovering certain distribution regulatory assets in their rates, beginning March 1, 2004. These assets primarily include market ready costs, retail settlement variance account balances and

certain environmental costs. Accordingly, on January 28, 2004, we filed an application with the OEB, in accordance with OEB filing guidelines, to adjust our distribution rates to recover the regulatory assets identified in the *Electricity Pricing, Conservation and Supply Act, 2002* for the first year of the four year recovery period commencing March 1, 2004, with rate adjustments to be implemented on April 1, 2004.

NARRATIVE 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, 2003. Our transmission system is one of the largest in North America based on assets as at December 31, 2003. Our distribution system is the largest in Ontario based on assets as at December 31, 2003 and spans approximately 75% of Ontario, serving approximately 1.2 million customers.

Our transmission business, which represented approximately \$6.6 billion of our assets as at December 31, 2003, transmits electricity through an approximately 28,600 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution network, 52 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 \$4.6 billion of our assets as at December 31, 2003, distributes electricity through our approximately 123,000 circuit-kilometre low-voltage distribution system to municipalities and in rural areas. Customers of our distribution business include 40 local distribution companies that are not directly connected to our transmission system, 47 large industrial customers and approximately 1.2 million rural and urban customers. Hydro One Brampton Inc. is an urban distribution company, serving approximately 103,200 customers in the Greater Toronto Area with approximately 4,200 circuit-kilometres of lines. We also operate 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 surplus fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of this segment constituted \$94 million of our total assets of \$11.3 billion as at December 31, 2003.

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. The OEB has approved a performance based regulatory framework for Ontario's electricity distribution business and is expected to implement a similar framework for our transmission business. Performance based regulation 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 performance based regulation, regulated utilities have greater incentives to improve their operating efficiency as they can participate in savings beyond certain thresholds established by the regulator.

The *Electricity Pricing, Conservation and Supply Act, 2002* suspended the implementation of the framework for performance based regulation for the distribution sector. The *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, however, anticipates full implementation of performance based regulation in the distribution sector over the next few years, and we anticipate our distribution returns to improve and approach full commercial return after 2006.

BUSINESS

Recent Developments

Ten Year Plan

Our company is in the process of finalizing a comprehensive transmission development plan for the next 10 years. This transmission plan will evolve in conjunction with the evolution of Ontario's electricity sector. For example, as the policy framework for demand side management develops in Ontario, our 10-year plan will be updated to reflect its impact. The plan will set out our transmission goals and the process we intend to follow to manage the development of the transmission system. In addition, it will describe the transmission solutions 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 employees as the best place to work in Canada; 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*: Focus on culture change to create and maintain an injury-free workplace. See “Health and Safety”.
- *Customer Service*: Become a more customer-focused company. We intend to undertake actions to continue to improve our customers’ level of satisfaction and we will strive to build relationships with our large and mid-sized customers that reflect their commercial requirements.
- *Reliability*: Maintain reliability and service standards in our transmission and distribution systems while continuing to develop and expand the transmission system to meet Ontario’s future needs. Further, we will continue to make productivity and cost reduction improvements. The resulting savings will be re-invested in the work programs described below.
- *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 and maintaining confidence and pride among our employees.
- *Productivity and Cost Effectiveness*: Continue to promote productivity and cost efficiency.

Focusing on Safety

Our top strategic priority is to create and maintain an injury-free workplace by 2006. Several strategic initiatives that were endorsed in 2003 will be fully implemented and a number of existing programs will be strengthened over the planning period in order to achieve the required cultural changes. These initiatives include a new health and safety policy with ambitious targets and a comprehensive health and safety management system for integrating all safety initiatives and documenting continuous improvement.

Improving our customer service focus

In May 2002, the Ontario electricity market was opened to wholesale and retail competition simultaneously. Customers experienced some price increases, primarily due to the volatility of the cost of purchased power, which is recovered in our distribution revenue. We have been actively helping our customers understand the changing market, changing government direction, and most importantly, our role in this new market.

For our household and seasonal customers, we have increased the capacity of our call centre and the services offered through our website. We have also completed the installation of an Outage Management Restoration System to give customers better information on local outage restoration efforts.

For our mid-size business customers, we have assigned Field Business Centres as a single point of contact available to the customer. We have found that our local presence has improved our responsiveness to our customers' growing needs.

For our large industrial and commercial customers, 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.

Focusing on 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 to ensure their reliability. To this end, transmission capital expenditures include the replacement of power transformers, protection and control equipment, line components and telecommunication equipment, among others, that have reached the end of their useful service life. In addition, we will continue to develop and expand the transmission system in order to meet Ontario's future needs with substantial increases in planned spending on new area supply. For example, completion of the Parkway transformer and double circuit 230 kV line project will enable us to safely and reliably supply the growing loads in the southern part of York Region and the Greater Toronto Area. See "Regulation – Transmission – Facilities Application". We will also continue to pursue interconnection and congestion relief initiatives for future development. These investments will facilitate the flow of electricity through our system, increase access to the Ontario market place and maintain or improve reliability in local transmission areas.

Key investment areas for the distribution capital work program will include refurbishment work such as the replacement of wood poles, power transformers and switches, to maintain the reliability of the system. To the same end, on a prioritized basis, older distribution installations, are currently being phased out and replaced with current standard, higher voltage equipment. Investments will also be made to meet growing demands on the distribution system.

Focusing on our core transmission and distribution businesses

Virtually all of our net income in 2003 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 will 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 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 2003. 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.

The distribution sector in Ontario remains fragmented with over 90 local distribution companies. The Province has introduced a tax exemption on the transfer of ownership of distribution assets when the transfer occurs between or among government-owned entities (either provincial or municipal). This tax exemption is available until March 2005. Our company will be an active participant in the OEB consultation process to review approaches to improve efficiencies and determine benefits of further consolidation of Ontario's electricity distribution sector. Our company may acquire and sell assets in order to facilitate the rational restructuring of the distribution sector in Ontario. We will consider such transactions where we can realize economic benefits.

Investing in new capacity in our core businesses

We plan to undertake projects to expand our existing systems. We have prepared a proactive 10 year transmission plan which we believe will enable us to connect customers in a timely and cost effective manner, to maintain reliable supply to large load pockets as the demand increases and to enable access to the lowest cost power available to electricity users in Ontario. Our plan includes increased supply capacity to the Greater Toronto Area, Ottawa area, Waterloo Region, Windsor area and the Simcoe Region. Furthermore, our plan includes transmission investments to accommodate the retirement of coal-fired generation stations in Ontario.

We are also considering investments to relieve transmission congestion in the Niagara area and between northwestern and northeastern Ontario. A significant amount of the proposed generation development (gas, wind and hydroelectric) is located in the northern and the southern regions of Ontario. We also contemplate transmission improvements in southwestern Ontario, and between Sudbury and Barrie to facilitate these generation developments. We expect all of these projects to be included in our regulated rate base.

The Province is interested in increasing both Ontario's domestic generation supply and the amount of electricity that may be imported. We therefore intend to continue development work on beneficial increases in intertie capacity between our system and those of neighbouring provinces and states. We will also be considering any recommendations resulting from the U.S.-Canada Power System Outage Task Force initiated in response to the August 14, 2003 blackout. These recommendations are expected in the first quarter of 2004.

Continuing our emphasis on reducing costs and improving productivity, while promoting safety

We believe our recent financial performance reflects our ability to reduce costs and improve productivity. In 2002, we outsourced non-core functions to Inergi LP, an affiliate of Cap Gemini Ernst & Young Canada Inc., resulting in a large transfer of staff to this organization. This arrangement is expected to continue until 2012. We have reduced costs and increased productivity through the centralization of operations and new flexible work rules and practices for our lines and forestry staff, such as temporary work headquarters. We have expanded our use of hiring halls to meet intermittent and seasonal work needs. All of these activities have resulted in a reduction in regular employees from 5,632 in 1999 to approximately 3,970 at December 31, 2003.

We believe that cost reductions and productivity improvements can be achieved through the joint management of our transmission and distribution businesses, Inergi LP outsourcing arrangement, the realization of additional economies of scale through the continued consolidation of the distribution sector,

and the consolidation of our system operations functions. We expect to consolidate our system operations functions, which are currently dispersed across Ontario, into a single operations centre by the third quarter of 2004, while maintaining a fully redundant back-up facility. This initiative is intended to produce lower costs and better service through the introduction of more technologically sophisticated operating systems.

We believe we have some of the best skilled and best trained electrical workers on the continent. 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.

Focusing on developing and maintaining confidence and pride among our employees

A number of key initiatives are underway, and existing initiatives will be strengthened, to ensure we develop and maintain the confidence and pride of our employees. Over the past few years, we have conducted an annual survey of our employees to determine the types of issues which will instil confidence and pride amongst them. The survey results are used to help shape our human resources programs. For example, we have stepped up our internal communications programs, and our management and supervisory development initiatives in response to these results. Our compensation schemes have been restructured to reward performance and motivate employees. We have also undertaken to create a new Mission, Vision and Values document to involve employees in the development of our company. Finally, we have recently developed a new human resources strategy which articulates the goals and aspirations of the company in terms of how we wish to treat our employees.

The demographics of our workforce is also an issue which we are monitoring, as the average age of our work force is 45 years with 19 years of service. In response to this issue, a comprehensive management development program as well as a succession planning program has been implemented. In addition, a significant hiring program has commenced together with apprenticeship and student programs currently underway will help to deal with future retirements.

Continuing to promote cost efficiency and productivity

We have achieved annual savings of 8% to 9% over the 2001 to 2003 period with productivity savings largely re-invested in work programs. Going forward, we believe that our opportunities for cost reduction and productivity savings will be more complex and difficult to achieve. We are targeting annual savings in the 2% to 5% range through initiatives such as the operating centre consolidation in Barrie, Ontario, the strategic sourcing of materials and services, and certain information technology initiatives. See “Our Transmission Business – Transmission Assets”. Over time, our target is to move to the top quartile in key unit cost metrics relative to our Canadian electricity industry peer group.

Our Transmission Business

Overview

Our transmission system operates at 500 kV, 230 kV and 115 kV and transmits electricity to customers consisting of 52 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 interties. Electricity is supplied by generators, both within and outside Ontario, of which 77 in Ontario are connected directly to the transmission grid. Our transmission system serves over four million customers, directly or indirectly, and transported 151.7 TWh of electricity throughout Ontario in 2003. Revenues from our transmission business accounted for approximately 33% and approximately 32% of our total revenues in 2002 and 2003, 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 highly integrated and operates synchronously, or at the same phase and frequency, with the North American eastern interconnected system that is comprised of virtually all of the electric utilities east of the Continental Divide. Our transmission business owns and operates 17 synchronous interties at 345 kV, 230 kV, 115 kV and 69 kV levels with New York (9), Michigan (4), Manitoba (3) and Minnesota (1). Our transmission business also owns and operates nine non-synchronous interties with Québec. A non-synchronous intertie is an intertie that links two electricity transmission systems that do not operate at the same phase or frequency. As a result of these interties, our system has a combined import capability of approximately 3,900 MW and a combined export capability of approximately 5,800 MW. These capabilities are based on the installed capacities of the interties. 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 transformer 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 271 circuit-kilometres of underground cables in urban areas.

The transmission system includes approximately 28,600 circuit-kilometres of high voltage lines whose major components consist of cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems.

Transmission Operations. We monitor, control and carry out real-time (i.e., instantaneous) management of our transmission system at our Transmission Operations Management Centre in Toronto, Ontario and two other Territory Operating Centres located in southern Ontario. The Transmission Operations Management Centre is our link to the IMO regarding the operation of our transmission system. The IMO manages the electricity marketplace and directs the operation of Ontario's integrated transmission network. Based on directions received from the IMO, the Transmission Operations Management Centre oversees the operations of our Territory Operating Centres which physically switch and control transmission. Switching is performed to provide reliable transmission service and acceptable power quality to our customers, protect our transmission assets, isolate equipment to facilitate maintenance, ensure the safety of maintenance personnel and restore equipment to service. We are currently in the process of rationalizing these operating centres together with our Distribution Operations Management Centre into one centre in Barrie, Ontario. We believe that this rationalization will substantially reduce our cost for real-time operation. We will maintain our Transmission Operations Management Centre in Toronto, Ontario in order to provide a fully redundant back-up to our new centre in Barrie.

Telecommunications Facilities for Transmission. 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 microwave radio, fibre-optic cable, power line carrier and mobile radio systems. The microwave radio system is nearing the end of its useful life and we are continuing with the replacement of the microwave system by a fibre-optic system.

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 intertie with the Province of Québec that would increase our intertie 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 needed to be isolated to either system for import or export). Although we had originally obtained the necessary regulatory approvals, Hydro Québec has not yet advised us that it has obtained its required regulatory approvals. Accordingly, we have sought from the OEB a further extension from December 31, 2003 of our approval to construct this facility in order to allow the project to proceed should Hydro Québec be in a position to do so. We have applied for a five-year extension, which the OEB is reviewing. In the meantime, the OEB has extended the expiry date of our approval for leave to construct this facility on an interim basis pending its decision. We and Hydro Québec acknowledge that construction will not proceed on this project in the near future.

Michigan. Two of our interties with the State of Michigan are currently being upgraded with the installation of three phase-shifting transformers and an autotransformer. Part of this installation has been completed but there are technical issues requiring resolution by the supplier of the equipment (the work required on our transformer is under warranty). As a result, the in-service date of the facilities is uncertain. This equipment is intended to provide us with greater control over the use of our Michigan interties so as to better control transactions directly across the Ontario-Michigan border and indirectly across the Ontario-New York border. This project is also intended to increase our export capacity by 1,000 MW and our import capacity by 500 MW.

Lake Erie Link. Hydro One and our partner, TransÉnergie US, a subsidiary of Hydro Québec, had jointly been developing a proposal for an under-water cable from Ontario to either Pennsylvania or Ohio, or both. We have U.S. Federal Energy Regulatory Commission approval to sell transmission rights on this project; such an approach is commonly referred to as “merchant” transmission. In 2002, we conducted a competitive auction process for long term rights on this link but, due to market conditions, the potential revenue was insufficient to support the entire investment in the project. As a result, we and TransÉnergie have agreed to suspend offering this link as a merchant project.

Manitoba. We are in the early stages of planning and development for a major new transmission line between northern Manitoba and Sudbury, 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 be between 2011 to 2014.

Our Distribution Business

Overview

Our distribution system provides customers with electricity distribution services through a low voltage distribution network. In 2003, 27.9 TWh of electricity were delivered through the distribution system to approximately 1.2 million customers located in rural and urban areas (including approximately 103,200 urban retail customers located in Brampton, Ontario). The distribution system also serves 40 local distribution companies that are not connected directly to our transmission system and 47 customers with loads exceeding 5 MW. The distribution system comprises approximately 123,000 circuit-kilometres of lines operating mainly at voltages of 50 kV or less and 1,032 distribution and regulating stations. Our distribution system distributes electricity from our transmission system and 96 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 66% and approximately 67% of our total revenues in 2002 and 2003, 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

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 56 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 an Interim Operating Agreement between Hydro One Remote Communities Inc. and the Attawapiskat First Nation (the "First Nation"), the First Nation is currently operating the distribution and generation assets. OEB approval for the sale to the First Nation of these distribution and generation assets will be sought in 2004. Hydro One's remote distribution facilities are exempted by regulation from Open Access. 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 – Implications of the *Electricity Pricing, Conservation and Supply Act, 2002* and The *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* for Distribution Revenues – Rate Orders for Remote Communities".

Our Telecommunications Business

Our telecommunications business 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 our microwave towers to wireless service providers.

Employees

On December 31, 2003, our Hydro One Networks subsidiary had 3,790 regular (i.e., permanent) employees comprised of 299 non-represented Executive and Managerial staff, 2,696 employees represented by the Power Workers' Union and 795 employees represented by the Society of Energy Professionals. In addition, our Hydro One Brampton subsidiary had 40 non-represented regular staff, 99 employees represented by the Canadian Auto Workers and 38 employees represented by the International Brotherhood of Electrical Workers. We also had 912 non-regular (i.e., temporary) employees comprised of 7 Executive and Managerial staff, 435 employees represented by the Power Workers' Union, 44 employees represented by the Society of Energy Professionals and 426 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, of which Hydro One is a key member.

In 2003, we negotiated a two-year collective agreement with the Power Workers' Union which will end on March 31, 2005. We have three-year agreements with the Canadian Auto Workers and the International Brotherhood of Electrical Workers in Brampton, both of which expire on March 31, 2005, a three-year agreement with the Canadian Union of Skilled Workers which expires on April 30, 2005 and a 27-month collective agreement with the Society of Energy Professionals which expires on March 31, 2005.

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 Cap Gemini Ernst & Young 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 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 first two years of the agreement.

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

The Hydro One Inc. Pension Plan was established on December 31, 1999. In accordance with an asset transfer agreement dated March 29, 2001 among the five successor corporations to Ontario Hydro, the assets and liabilities of the Ontario Electricity Financial Corporation Plan (formerly the Ontario Hydro Pension and Insurance Plan) were transferred in proportionate shares to new pension plans established by the successors to Ontario Hydro in accordance with the provisions of the *Electricity Act, 1998*. The transfer was approved by the Superintendent of Financial Services and commenced on June 29, 2001. Our company's portion of these assets and liabilities is now managed and invested by our company as plan sponsor and administrator of the Hydro One Inc. Pension Plan. As of December 31, 2003, there were 3,835 active members and 7,774 pensioners and disabled and deferred members.

Effective December 31, 1999, we established the Hydro One Inc. Supplementary Pension Plan to provide supplementary pension benefits on the same terms as provided pursuant to the supplementary plan previously maintained by Ontario Hydro. 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. 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⁾	244 sites	19	194	14	17
Switching stations ⁽⁴⁾⁽⁶⁾	30 sites	1	10	4	15
Transmission operating centres ⁽⁷⁾	5 sites	—	5	—	—
Distribution stations ⁽⁴⁾⁽⁸⁾	962 sites	938	—	11	13
Regulating stations ⁽⁴⁾	73 sites	69	1	2	1
Administrative and service centres ⁽⁹⁾	176 sites	63	66	41 ⁽⁷⁾	6
Leases and Subleases ⁽¹⁰⁾	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 currently in use, was transferred to the Province and applied as a reduction of shareholder's equity.
- (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 to the Province.
- (4) Comprises the total number of operating stations.
- (5) The total includes one Transformer Station site that is owned by Hydro One Brampton Networks Inc. and 18 owned by Hydro One Networks Inc. 212 sites (lands only) were originally transferred to the Province pursuant to the Act; however, 18 of these sites were transferred back to Hydro One Networks Inc. on or before December 31, 2003.
- (6) A total of 10 sites (land only) were transferred to the Province pursuant to the Act.

- (7) The total number of Transmission Operating Centres is comprised of four transmission and one distribution centres. These centres will be further reduced to two facilities by May 31, 2004, which includes a backup facility. All of the centre sites (lands only) were transferred to the Province pursuant to the Act.
- (8) 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, 18 stations sites are associated with Hydro One Brampton Networks Inc., 15 owned and three leased.
- (9) The total number of Administrative and Service Centres includes two leases associated with the former Ontario Hydro Energy Inc. and an owned Hydro One Brampton Networks Inc. site. A total of 66 Administrative and Service Centre sites (lands only), which includes 33 Administrative and Service Centres located within Transformer Station sites were transferred to the Province pursuant to the Act. These centres are largely independent of the transformer station function, but in some instances staff operate from buildings that serve both functions.
- (10) 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 a spill and leak prevention program involving the testing, replacement, repair and installation of containment systems and the regasketing of transformers. 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. Our current estimate for future PCB expenditures is approximately \$50 million as of December 31, 2003 over the next 27 years.

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 total program to the end of 2003 has involved 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 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 \$55 million over the next seven years.

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. Further, the scientific community has been in agreement for some time that if a risk were to be established, it would be a low risk. We have sponsored research in the past and are now focusing on monitoring national and international developments. We also maintain a dialogue with the Province's Ministry of Health and Long Term Care regarding this issue. Partnerships with provincial and municipal agencies are in place to develop appropriate actions and communicate with the public. Electric and magnetic fields are not currently regulated by either the federal or provincial governments and we do not know 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 containing 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.

On March 29, 1999 and May 24, 2001, 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. 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. To date, we have not filed a defence. We have requested particulars of the claims and further and better particulars of the claims as did the other defendants. As a result of the particulars filed, the Attorney General of Canada brought various motions, which we supported, to strike out various claims and for better responses to the demands for better particulars. In September 2003, the Ontario Superior Court of Justice struck out the claims with leave to amend. The Whitesand Band has now amended its claims and there may be further procedural motions before we file a defence. Additionally, this case was consolidated with the Red Rock case noted below. The flooding alleged to have been caused by Ontario Hydro is a matter for which we believe Ontario Power Generation Inc. would have responsibility pursuant to transfer orders under the *Electricity Act, 1998*. We believe 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.

On September 7, 2001, the Red Rock First Nation Band commenced an action in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, Ontario Electricity Financial Corporation, Ontario Power Generation Inc. and our company. This claim is similar in form to the claim of the Whitesand First Nation Band and the same lawyer is acting for the Red Rock Band. The Band seeks declaratory relief and claims an unspecified amount of damages for trespass, breach of fiduciary duties, public and private nuisance and unpaid lease payments relating to a transmission line or right-of-way. The same motions brought in the Whitesand case discussed above were brought in this case with the same result. This case has been consolidated with the Whitesand case. The Red Rock and Whitesand claims have been amended. It is likely there will be further procedural motions in this case before we file a defence. We cannot yet fully assess what the likelihood is that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects, but believe that such a result is unlikely.

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 for our employees and contractors, to developing practices that lead to injury prevention and to minimizing the risk of injury to the public associated with its 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 accident severity rate and lost-time injury frequency rate and 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. In 2003, we developed an action plan to achieve our new, aggressive safety targets. Actions currently underway include increasing the field presence of supervisors, ensuring clear and consistent standards for work performance and improving safety communications. Work site inspections and effective job planning 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 our job planning and prevent recurrences.

Hydro One is currently integrating 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*, primarily establish the broad legislative framework for Ontario's competitive electricity market. The *Electricity Act, 1998* implements 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 were amended by the *Reliable Energy and Consumer Protection Act, 2002*, which received Royal Assent and was proclaimed into force on June 27, 2002, and the *Electricity Pricing, Conservation and Supply Act, 2002* which received Royal Assent and substantially all of its provisions were proclaimed into force on December 9, 2002. Furthermore, on December 18, 2003, the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* received Royal Assent and will come into force upon proclamation. the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, when proclaimed into force, will amend the *Ontario Energy Board Act, 1998*. See “– The *Electricity Pricing, Conservation and Supply Act, 2002* and the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*”.

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 IMO. The IMO 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 IMO-controlled grid. The IMO itself is licensed by the OEB and funded through fees which are approved by the OEB and levied on all market participants. See “– Contractual Arrangements, Codes and Licences – Operating Agreement with the IMO.”

Market participants may buy and sell electricity from the wholesale spot markets, administered by the IMO. Alternatively, they may contract such transactions with each other, albeit with the obligation to schedule these transactions with the IMO.

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 “General Development of the Business” and “– 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 “– Contractual Arrangements, Codes and Licences – Electricity Industry Codes”. As a result of the *Electricity Pricing, Conservation and Supply Act, 2002* and associated regulations, we will continue to provide this service to low volume and designated consumers at a fixed price of 4.3 cents per kWh until the date when the pricing arrangements mandated by the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* will be implemented, which date is anticipated to be April 1, 2004.

Reforms to the Ontario Energy Board

On April 15, 2003, the Minister of Energy announced the Province's plans to reform the OEB. The legislation was proclaimed in August 2003 and makes the OEB self-financing, while maintaining it as a Crown agency; sets the terms of OEB board members for an initial two-year term, with renewal terms of up to five years; establishes a management committee to deal with day-to-day administrative duties of the OEB, allowing board members to focus their full attention on hearings and to delegate routine decision-making responsibility to OEB staff members; establishes an advisory committee of stakeholders, industry representatives and consumers to annually review the OEB's performance measures; establishes a regulatory calendar with a statement of priorities to increase accountability and ensure that stringent timelines are established; develops criteria for consumer protection support to ensure that consumers have input into the hearings process and enhances the board's communications role to educate and protect consumers and; harmonizes the OEB's powers in the regulation of natural gas and electricity.

The Electricity Pricing, Conservation and Supply Act, 2002 and the Ontario Energy Board Amendment Act (Electricity Pricing), 2003

Critical Features of the Electricity Pricing, Conservation and Supply Act, 2002 for the Businesses of Hydro One

The features of the *Electricity Pricing, Conservation and Supply Act, 2002* which will continue to affect the transmission and distribution businesses of Hydro One until such time that the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* is proclaimed, and which were planned to be in effect until April 30, 2006, include the following:

- Effective December 1, 2002, the electricity commodity price was set at 4.3 cents per kWh for low volume and designated consumers which include:
 - consumers using not more than 250,000 kWh annually; and
 - municipalities, farms, universities, schools, hospitals and registered charities, and certain social service and cultural organizations designated by regulation.
- Remaining customers would continue to pay commodity prices determined by the market or commercial contracts.
- The prices that all consumers pay for transmission and distribution of electricity used on or after December 1, 2002 are frozen at the levels in effect on November 11, 2002. Accordingly, some of our approved rates, such as those for low voltage customers, which had not been put into effect by November 11, 2002 were not implemented. See “– Distribution – Implications of the *Electricity Pricing, Conservation and Supply Act, 2002* and the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* for Distribution Revenues.”
- Reviews of rate applications which had not resulted in an OEB order before December 9, 2002 were discontinued and all rates which had been given interim approval by the OEB were deemed

to be final. This affected our pending application for new rates for our remote customers. Their rates for 2002, which had been given interim approval, therefore, became final. The approved changes to Hydro One's rates for 87 of our acquired municipal utilities were frozen at 2001 levels. Distribution rates for our acquired subsidiary, Hydro One Brampton Networks Inc., had already been approved for 2002. See “– Distribution – Implications of the *Electricity Pricing, Conservation and Supply Act, 2002* and the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* for Distribution Revenues” and “– Distribution – Rate Orders for Remote Communities.”

- Distributors and transmitters cannot apply to the OEB for changes in rate orders without the approval of the Minister of Energy.
- Electricity consumers are not allowed to be disconnected for failure to pay their bills until April 1, 2003.
- The Minister must continue to approve new market rules and changes to existing rules and may also revoke amendments if they are determined to unduly and adversely affect consumers' interests with respect to prices or electricity service reliability or quality. Revoked amendments are referred back to the IMO for further consideration.

Critical Features of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*

The features of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* which, upon proclamation, will affect our businesses include the following:

- Effective April 1, 2004, the current price cap of 4.3 cents per KWh for electricity for low volume and designated customers will be replaced with an interim pricing plan which fixes the commodity price for the first 750 KWh of electricity consumption per month at 4.7 cents per KWh and consumption in excess of that amount at 5.5 cents per KWh. This interim pricing plan will remain in effect until the OEB develops a new commodity pricing mechanism which is to be implemented as soon as possible and, in any event, by no later than May 1, 2005. Remaining customers would continue to pay commodity prices determined by the market or commercial contracts.
- The requirement to obtain Ministerial approval to make an application relating to transmission rates will be removed.

Local distributors' deferred costs, the recovery of which had been suspended by *Electricity Pricing, Conservation and Supply Act, 2002*, may be recovered over a four-year period beginning in April, 2004, subject to a prudence review by the OEB.

Ministerial approval will still be required for applications for new rates for distribution businesses and the Minister maintains authority over the OEB's power to commence distribution rate proceedings and to review its own rate orders for distributors. The Minister also will continue to have the right to direct the OEB to review or amend distribution rate orders. However, it is anticipated that the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* will restore the distribution regulatory regime by no later than May 1, 2005.

The Province has also indicated that, subject to regulations and OEB direction, local distributors, including Hydro One's distribution business, will be allowed to recover their full commercial return, conditional on their re-investing the equivalent of one year of these revenues in conservation and demand

management initiatives. We expect our distribution business returns to improve and approach full commercial return after 2006.

Contractual Arrangements, Codes and Licences

Operating Agreement with the IMO

Under the *Electricity Act, 1998*, the IMO 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 IMO, 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 IMO-controlled grid; provides that the IMO 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 IMO regarding the operation of these facilities; provides for co-ordination between Hydro One Networks Inc. and the IMO 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 IMO 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 IMO. The local distribution companies must advise the IMO of any conditions in their distribution system that may affect the ability of embedded generators and loads to participate in the broader IMO-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 Code of Conduct for Electricity Retailers. These Codes and requirements prescribe minimum standards of conduct and standards of service for transmitters, distributors and retailers in the competitive electricity market.

The Affiliate Relationships Code for Electricity Distributors and Transmitters became effective on October 1, 1999. This Code 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 became effective upon May 1, 2002. This Code governs the conduct of distributors, including our company, in their provision of standard supply service pursuant to the *Electricity Act, 1998* and the terms of their distribution licences. Under the Standard Supply Service 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 *Electricity Pricing, Conservation and Supply Act, 2002* and the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, however, our prices for standard supply service will be established by regulation until the OEB develops and implements a new commodity pricing mechanism which, pursuant to the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, must be implemented by no later than May 1, 2005. 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 under its licence and the *Electricity Act, 1998*.

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. The Code came into force upon May 1, 2002. On June 14, 2002, the OEB initiated a two-phase process to review the Transmission System Code and related matters. The OEB's decision on the first phase, to determine the principles governing issues relating to transmission system by-pass, available capacity, cost responsibility, economic evaluation and contestability, is expected early in 2004. The codification of the principles, along with other issues such as cost responsibility, dispute resolution and reporting and monitoring, will be addressed in the second phase of the OEB's review.

The Distribution System Code came into force upon May 1, 2002, with the exception of those provisions relating to connections, expansions and responsibilities to generators, which had already been in effect. In the first quarter of 2004, the OEB is expected to issue changes to the Distribution System Code regarding generator connections to distribution systems. This follows a consultation during 2003 with stakeholders. The purpose of the revisions is to clarify and streamline the process and requirements for such connections.

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 designed to ensure that, subject to credit risk, distributors will not make or lose money in their role as retail market settlement administrators. 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. Aspects of this Code may require revision to reflect the new pricing structure to be introduced by the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*.

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 Electricity Reporting and Record Keeping Requirements which the OEB issued in October 2002. New licences for our Brampton subsidiary's distribution business, for our remote communities' generation and distribution businesses and for our transmission business have been issued. The review of our distribution licences for our main business operated by Hydro One Networks Inc. is underway. The OEB has extended our transitional licence for this business until June 30, 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 IMO***— We are required to enter into the operating agreement with the IMO, providing for the IMO’s direction of the operation of our transmission system. On June 8, 2001, we signed our operating agreement with the IMO. See “– Contractual Arrangements, Codes and Licences – Operating Agreement with the IMO”.
- ***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 IMO, 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 must use our best efforts to expand our intertie capacity to neighbouring jurisdictions by 2,000 MW by May 1, 2005 and must update the OEB after that date 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, the licences:

- require the distribution business to keep its financial records separate from those of the transmission business;
- 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;
- require compliance with the Retail Settlement Code and the Affiliate Relationships Code for Electricity Distributors and Transmitters;
- prescribe the manner by which we must pass through any rebates from Ontario Power Generation Inc. to customers; and
- 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 in 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 and a rate of return on deemed common equity of 9.88%.

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.

Prior to May 1, 2002, these transmission rates were charged as part of a single bundled rate for the operation, transmission and distribution of electricity. As of May 1, 2002, the rates charged to customers were unbundled and load customers are now charged in a transparent manner for their use of the transmission system based on the approved transmission rate. The IMO collects transmission revenues for our company and remits these to us on a monthly basis.

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 will 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.

On April 14, 2003, the OEB issued its principles and preliminary propositions in its review of the Transmission System Code for intervenor response. In the area of transmission by-pass, the OEB appears to expand the instances where transmission by-pass would be allowed. In a written submission for this phase filed in June 2003, we registered with the OEB the negative concerns and implications for transmitters and transmission pool customers that would arise from expanding by-pass opportunities. An OEB-sponsored settlement conference among the intervenors that was concluded on September 24, 2003 resulted in a limited consensus but added some clarity to opposing positions on unsettled issues. The OEB's decision on Phase One (determining principles and propositions) is expected in early 2004. Although the OEB has not yet formalized the schedule for Phase Two (implementation of the principles and propositions), we anticipate that an industry working group will be established to develop and recommend changes to the Code. These should include considerations for the implementation of changes to reflect the Phase One findings.

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. As these applications, in our view, constituted a by-pass of our transmission facilities, we opposed them. 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. We accordingly refunded \$2.8 million in total to the two companies and are now preparing to seek OEB approval to record the refund amount in a deferral account for future recovery.

Facilities Applications

Transmitters constructing facilities in Ontario are required to apply to the OEB for leave to construct, if the facilities comprise or include a transmission line that is greater than two kilometers. From time to time, we will apply to the OEB for leave to construct transmission facilities.

In February 2003, we applied to the OEB for leave to construct a transmission line to augment the existing supply in Ottawa which will be needed by the summer of 2004. Following a written proceeding in May 2003, we received approval on July 10, 2003 and construction has begun.

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. Our application requested an exemption from the need for a hearing due to the anticipated lack of electricity supply in portions of the Greater Toronto Area in the summer of 2005 and the resulting need for an urgent decision. The OEB, citing the de-registration of Lakeview Generating Station and the IMO's support for urgent attention to the issue, granted this exemption and approved the application without a hearing on December 24, 2003. The OEB's decision, however, contains a number of conditions, one of which is the expiry of this exemption

by March 31, 2004, if construction has not begun by that time. We plan to begin construction within this time frame.

We expect to apply for leave to construct other transmission projects in 2004.

Although we received the needed regulatory approvals from the OEB for an increase of our intertie capacity with Hydro Québec, Hydro Québec has not received the equivalent approval from the Régie de l'Énergie. We have requested an extension to our approval for leave to construct this facility from the OEB. We and Hydro Québec acknowledge that construction will not proceed on this project in the near term.

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.

Distribution

Current Rate Orders and Review of the Existing 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, net costs and expenses of \$324 million, and payments in lieu of corporate income tax of \$78 million. 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%.

Our May 1, 2000 application for unbundled distribution rates reflected a market based rate of return which would have resulted in an approximately 1% increase in customers' electricity bills. Applications from other distributors which were seeking commercial rates of return for the first time as well as a higher cost of power than our distribution business or, would have resulted in significant rate increases. Accordingly, the Minister directed the OEB to protect customer interests when approving distribution rates. In response, the OEB instructed distributors to re-file their rate applications with a plan to phase-in any increases evenly over three years to lessen the impact on consumers.

We therefore 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. This application reflected the anticipated increase in our wholesale cost of power yet mitigated the full impact of this increase on our customers by reducing our distribution revenues. As a result, our distribution revenues were 21% lower as of October 1, 2001, 15% lower as of March 1, 2002 and 9% lower as of March 1, 2003 than the distribution revenues in place prior to June 2001. Subsequently, pursuant to a regulation made under the *Electricity Act, 1998*, Ontario Power Generation Inc. was required to increase its wholesale cost of power to us by an additional 1.15 cents per kWh effective October 1, 2001 in order that our power costs would be consistent with the power costs of other large electricity distributors. This increase was consistent with the anticipated increase in our wholesale cost of power reflected in our amended application that was expected to be implemented upon Open Access.

On August 30, 2002, the OEB issued its final rate order for our distribution business, approving aggregate revenues that we had requested with one exception: \$12.9 million of low voltage costs were transferred from our low voltage customers to our retail customers. 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. In each of 2001, 2002 and 2003, rates were approved to recover revenues of \$25.7 million from embedded direct customers and distributors directly connected to our low voltage system, and miscellaneous charges were set to recover \$13.7 million. To address a revenue shortfall, our company embarked on a cost reduction and deferral plan to address the revenue shortfall during the transition period (2000-2003).

Implications of the Electricity Pricing, Conservation and Supply Act, 2002 and the Ontario Energy Board Amendment Act (Electricity Pricing), 2003 for Distribution Revenues

The *Electricity Pricing, Conservation and Supply Act, 2002* suspended the third phase of our core distribution business' approved rate increase, recovery of our approved low voltage rates and also recovery of deferred regulatory costs such as transition costs and variance accounts. It also suspended the recovery of low voltage costs and froze distribution rates for our acquired customers at the first stage of commercial return. Further, it stipulated that all applications respecting distribution rates must first be approved by the Minister before proceeding to the OEB.

The *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, which received Royal Assent in December 2003 and will come into force upon proclamation, will enable the restoration of the regulatory regime for the distribution business over the next few years. In conjunction with the introduction of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, distributors may now start recovering certain distribution regulatory assets in their rates, beginning March 1, 2004. These assets primarily include market ready costs, retail settlement variance account balances and certain environmental costs. Accordingly, on January 28, 2004, we filed an application with the OEB, in accordance with OEB filing guidelines, to adjust our distribution rates to recover the regulatory assets identified in the *Electricity Pricing, Conservation and Supply Act, 2002* over the four year recovery period commencing March 1, 2004, with rate adjustments to be implemented on April 1, 2004.

Rate Orders for Remote Communities

Hydro One's Remote Communities business is exempt from a number of sections of the *Electricity Act, 1998* which relate to the competitive market. For example, it continues to apply bundled rates to its customers. 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.

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 date of Open Access, May 1, 2002, the OEB was required to calculate the amount of rate reduction for those consumers who occupy rural residential premises in a manner that it forecast would result in the weighted average rural bill not exceeding the weighted average municipal bill by more than 15%. Our remote customers also receive protection so that the rates charged to them are no greater than the rates charged to the lowest density comparable class of our rural customers. Our distribution rate order approves the maintenance of existing subsidized rates for remote and rural customers.

From May 1, 2002 until December 31, 2004, 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 based on the amount that they received in 2001. The amounts to be received by our remote customers for each of the years 2003 and 2004 are expected to remain at the same level of \$21 million.

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 IMO 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 IMO based upon the latter's forecast of the number of kilowatt-hours of electricity that will be withdrawn from the IMO-controlled grid. We maintain a variance account to track any surplus or deficit in the amount received from the IMO and from the \$127 million prescribed amount.

Our Remote Communities business is to be 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 has implemented a short form expedited approval process to deal with such licence amendment applications. In 2003, our Hydro One Networks Inc. subsidiary supported an application by our Brampton subsidiary to provide service to a sub-division adjacent to its own territory, as it may do so at lower cost than Networks. Similarly, other distributors have supported Hydro One Networks Inc. in an application to connect three customers from their jurisdictions.

In other instances, however, a distributor may request distribution licence amendments which would allow them to serve larger geographic areas currently served by other distributors. Certain distributors have filed applications requesting approval to expand their service territories to their municipal boundaries, overlapping areas already served by Hydro One Networks Inc. As approximately 25% of our company's 1.2 million customers now fall within the boundaries of municipalities served by another distributor, such expansions could result in under-utilization or stranding of Hydro One assets installed to meet projected growth trends in these areas, with attendant upward pressures on distribution rates.

The OEB convened a generic hearing in December 2003 to determine the principles which will apply to such licence amendment applications. Until a decision from this proceeding is issued, any new application by a distributor wishing to serve in Hydro One Networks Inc.'s service area which are not supported by Hydro One will not be processed. During this proceeding, some parties proposed that

competition in the distribution business was desirable, whereas Hydro One Networks Inc., supported by a consumer association, the Power Workers' Union and a coalition of large distributors, submitted that electricity distribution is a natural monopoly and that overlapping service areas should be avoided.

The OEB is considering the evidence and a decision on the guiding principles for licence amendments is expected to be issued in the first quarter of 2004. Once this decision is issued, the OEB will review evidence on the specific applications for territory expansions and customer connections.

RECENT DEVELOPMENTS

Following a consultation with stakeholders in response to a Ministerial directive, the OEB issued a draft report on Demand Side Management and Demand Response on January 23, 2004, with a request for further stakeholder input by mid-February, 2004 and a final report to be submitted to the Ministry of Energy in March 2004.

On January 21, 2004, the OEB announced a consultation to review approaches to improve efficiencies and determine benefits of further consolidation of Ontario's electricity distribution sector. We support the pursuit of greater efficiencies and are preparing our submission.

RISK FACTORS

You should carefully consider the following risks before purchasing our securities. If any of the circumstances discussed below occurs, our business, results of operations, financial condition and prospects could be adversely affected, in which case the trading prices of our securities could decline.

Risks Related to our Industry

Our financial performance depends on our ability to manage our costs in accordance with our current rate orders for a longer period than originally planned.

Our electricity transmission and distribution businesses are subject to regulation, principally by the OEB. The OEB generally has the authority to approve the revenue requirements and to set rates for our transmission and distribution businesses. Accordingly, we are highly dependent upon rate orders that appropriately reflect our revenue requirements and our commitment to manage to approved cost levels over a predictable time frame.

In 2001, following discussions with our shareholder, which requested us to mitigate the anticipated transition to higher electricity costs for our core distribution customers, we applied for lower distribution revenues than we had originally proposed. Further, any increase in revenues would be implemented in stages, with the last stage to be implemented on March 1, 2003. This revised proposal was approved, thereby comprising the final rate order for our distribution business. The proclamation of the *Electricity Pricing, Conservation and Supply Act, 2002* in late 2002 suspended the third phase of our core distribution business' approved rate increase, recovery of our approved low voltage rates and also recovery of deferred regulatory costs, such as transition costs and variance accounts. It also suspended the recovery of low voltage costs and froze distribution rates for our acquired customers at the first stage of commercial return. For both the transmission and distribution businesses, this Act stipulated that all applications for new or changed rate orders must first be approved by the Minister of Energy before proceeding to the OEB. The *Electricity Pricing, Conservation and Supply Act*, therefore, entailed a continuing commitment to manage within approved cost levels and productivity expectations over a time frame different from that envisaged by both our company and the OEB.

The *Ontario Energy Board Amendment Act (Electricity Pricing)*, 2003, which received Royal Assent in December 2003 and will come into force upon proclamation, restores the rate regime for transmitters and the authority of the OEB to review and approve transmission rates without prior ministerial authorization. Ministerial approval continues to be required prior to any submission to the OEB for distribution rate adjustments. Accordingly, the time frame within which we must manage our distribution business to the approved cost levels and productivity expectations remains uncertain.

We may not be allowed full recovery of our regulatory assets, which could negatively affect our profitability in future periods.

As a result of our distribution rate application dated January 28, 2004, we expect to begin recovering those distribution regulatory asset balances whose inclusion in rates was delayed by the *Electricity Pricing, Conservation and Supply Act*, over a four-year period, effective March 1, 2004. These assets include market ready costs, retail settlement variance account balances, certain environmental costs and other regulatory assets allowed by the OEB. The balances to be recovered will be subject to the OEB's approval following their review of these amounts. We expect that previously approved interim recoveries, such as for market-ready costs, will cease concurrently with the commencement of the new recoveries, and will have an immaterial impact on our net income.

As the balances of these regulatory assets will be subject to OEB review and approval, there is some risk that certain amounts may be deemed ineligible for recovery. As the timing and specific mechanism for the OEB review has not yet been communicated to us, we cannot assess which criteria will be applied by the regulator to establish eligibility for recovery. In the event that some element of our regulatory assets is disallowed, the appropriate regulatory asset balance will be written off in the period when that regulatory decision is rendered, which could have a material impact on our net income.

The *Electricity Pricing, Conservation and Supply Act* suspended a previously approved increase in rates to local distribution companies and directly connected customers of our low-voltage system that amounted to approximately \$26 million per year. This Act allowed us to establish a regulatory deferral account to track low voltage amounts for potential future recovery. However, this amount has not been recognized as an asset in our financial statements as the requisite level of assurance of recovery has not yet been attained. Similarly, we have not recognized certain interest accretion amounts related to some of our regulatory assets due to uncertainty of recovery. Once we determine that future recovery of these low voltage and interest amounts is reasonably assured, we will recognize the appropriate regulatory assets and record a gain in our results of operations, which could have a material impact on our net income.

Risks related to our company

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 2004 and 2007, including \$472 million maturing in 2004 and \$539 million maturing in 2005. We also plan to incur total capital expenditures of approximately \$670 million in 2004. We expect our base capital expenditures to remain in the \$550 million to \$600 million range annually over the next several years for the sustainment of the core system. Additional expenditures may be required for significant projects that we may undertake to expand our existing systems. 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 could experience service disruptions and increased costs if we fail to maintain and improve our aging asset base.

Our asset base requires substantial maintenance, improvement and expansion. We acquired transmission and distribution assets from Ontario Hydro that were, in some cases, relatively old and, potentially, subject to becoming less reliable. Ontario Hydro also had deferred maintenance spending on some of these assets during the mid to late 1990s in favour of allocating funds to other business units. As a result, we have been making significant capital expenditures to maintain or improve many of these assets and to enhance our asset management and monitoring processes. We expect to make significant capital expenditures with respect to these assets for at least the next several years. Any failure to carry out these programs to maintain and improve our asset base could have a material adverse effect on our company.

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 or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase the flexibility to conduct operations in a more cost-efficient manner. Although we believe that we have achieved improved relations with these unions over the last three years, which have resulted in more flexible collective agreements, we may not be able to maintain or further improve these relations. 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.

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 Cap Gemini Ernst & Young 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.

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*, as amended, 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*, as amended, 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 of payments 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.

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. 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. Primarily, as a result of expected revisions to Environment Canada's draft regulations for the management of PCBs, we have reduced our estimate of future expenditures by approximately \$95 million. However, this amount may have to be revised if the draft regulations are not passed as expected. We monitor regulatory developments and have provided input to proposed regulations that has been accepted.

While we would seek approval from the OEB to recover unplanned costs after the current rate freeze, future rate orders may not allow us to recover these costs in our rates charged to our customers. We do not have insurance coverage for these remediation costs. In addition, any contamination on our properties

could limit our ability to sell these assets in the future. Any future changes in environmental regulations, or in their enforcement, may result in additional material changes to the estimates used to calculate the environmental obligations and associated regulatory assets on our balance sheet. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liability on our balance sheet.

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 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 generating plant of a third party 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 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. In the event of a large uninsured loss to our transmission business, we might apply to the OEB for the recovery in our future rate orders of increased costs. However, as a result of the continued application of the *Electricity Pricing, Conservation and Supply Act, 2002* to distributors, an equivalent application on behalf of our distribution business must be approved first by the Minister of Energy before proceeding to the OEB. In either case, 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.

On August 14, 2003, the northeastern U.S. and Ontario suffered one of the largest power blackouts in the history of North America. The joint U.S.-Canada Power System Outage Task Force was created to identify the causes of the blackout and to develop recommendations to prevent and limit future outages. Recommendations from either the Task Force or other stakeholders may have a significant effect on the costs of our company.

Our profitability and cash flow could be negatively affected by possibly 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 0.129% of our total assets as at December 31, 2003 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, until such time as the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* is proclaimed, we may apply to the OEB subject to the prior approval of the Ministry of Energy, for the recovery in our future rate orders of increased costs. However, as a result of the continued application of the *Electricity Pricing, Conservation and Supply Act, 2002*, as it pertains to distributors, an equivalent application on behalf of our distribution business must be approved first by the Minister of Energy before proceeding to the OEB. In either case, 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.

We may be required 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. We are currently entitled to a contribution holiday based on a valuation as at December 31, 2000 that indicated the plan had a surplus. We are required to revalue our pension plan effective December 31, 2003. We currently estimate that contributions of approximately \$100 million per year for the next 3 years could be required once our next actuarial valuation is filed. The actual amount of the contributions that may be required in the future will depend on future investment returns, changes in benefits or actuarial assumptions. Should financial market conditions improve significantly before December 31, 2006, we have the option to file an earlier actuarial valuation.

We have requested approval from the Minister of Energy to apply for the recovery of any increased ongoing expenses related to pension costs through future rate applications for our transmission and distribution businesses. This request is under consideration, however we have not received direction to proceed with such applications to the OEB. If direction is not received, pension costs will be charged to the results of operations in the years that the contributions are made.

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.

Forward-looking information in this Annual Information Form is subject to risks and uncertainties.

We have included forward-looking statements in this Annual Information Form, including forward-looking statements relating to, among other things, our strategy, future rate orders and regulatory developments and planned capital expenditures. We have used the words “may”, “will”, “expect”, “anticipate”, “believe”, “estimate”, “plan” and similar expressions in this Annual Information Form to identify forward-looking statements. We have based these forward-looking statements on our current views with respect to future events and financial performance. Actual results could differ materially from those projected in the forward-looking statements. These forward-looking statements are subject to the risks, uncertainties and assumptions discussed in this “Risk Factors” section and elsewhere in this Annual Information Form. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or circumstances or otherwise.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

	For the year ended December 31, (Canadian dollars in millions, except per share data)		
CANADIAN GAAP			
Statement of Operations Data	<u>2001</u>	<u>2002</u>	<u>2003</u>
Total revenues	3,466	4,031	4,058
Operating costs	2,475	3,101	3,121
Financing charges	350	353	348
Payments in lieu of corporate income taxes	267	233	193
Net income	374	344	396
Basic and fully diluted earnings per common share ⁽¹⁾	3,562	3,258	3,779

(1) Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

Note: This table should be read in conjunction with the consolidated financial statements.

CANADIAN GAAP	<u>As at December 31,</u> <u>(Canadian dollars in millions)</u>		
Balance Sheet Data	<u>2001</u>	<u>2002</u>	<u>2003</u>
Assets			
Transmission	6,693	6,638	6,589
Distribution (including retail)	4,416	4,694	4,623
Other	122	90	94
Total assets	11,231	11,422	11,306
Current liabilities (including current portion of long-term debt)	1,625	1,894	1,192
Long-term debt	4,079	3,938	4,539
Other long-term liabilities	1,533	1,451	1,284
Shareholder's equity			
Share capital	3,637	3,637	3,637
Retained earnings	357	502	654
Total liabilities and shareholder's equity	11,231	11,422	11,306

Note: This table should be read in conjunction with the consolidated financial statements.

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2002 through December 31, 2003. This information has been derived from our unaudited consolidated financial statements which, in the opinion of our management, have been prepared on a basis consistent with the audited consolidated financial statements contained elsewhere in this Annual Information Form and include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period. You should not rely on them to predict our future performance.

	<u>Quarter Ended</u>							
	<u>31-03-02</u>	<u>30-06-02</u>	<u>30-09-02</u>	<u>31-12-02</u>	<u>31-03-03</u>	<u>30-06-03</u>	<u>30-09-03</u>	<u>31-12-03</u>
	<u>(Canadian dollars in millions)</u>							
Total revenue⁽¹⁾	1,022	913	1,097	999	1,147	953	949	1,009
Net income	106	99	112	27	139	85	93	79
Net income to common shareholder	101	95	107	23	134	81	88	75

(1) The demand for electricity generally follows normal weather related variations and therefore our energy related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

Dividends

Our preferred shares are entitled to a total annual dividend of \$18 million which is payable quarterly. The declaration and payment of dividends on our common shares are at the sole discretion of our Board of Directors, but will be dependent upon our results of operations, financial condition, cash requirements and other relevant factors. In 2003, we have paid dividends on our common shares of \$226 million, of which amount \$61 million was declared for the fourth quarter of 2002 (2002 - \$174 million; 2001 - \$240 million).

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to our 2003 Management's Discussion and Analysis which is incorporated herein by reference.

MARKET FOR SECURITIES

Our 6.94% Debentures due 2005, 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, 3.400% Notes due March 28, 2004, 3.450% Notes due May 31, 2004, 4.00% Notes due October 31, 2005, 4.100% Notes due January 30, 2006, 4.150% Notes due April 21, 2006, 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 and 4.550% Notes due August 10, 2007 are not listed on any exchange or similar market for securities.

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, 2003

<u>Name and Municipality of Residence</u>	<u>Principal Occupation</u>
Rita Burak ⁽²⁾ Toronto, Ontario (Director since June 11, 2002 and Chair since May 30, 2003)	Chair of the Board of Directors of Hydro One Inc.
W. Geoffrey Beattie ⁽¹⁾⁽³⁾ Toronto, Ontario (Director since June 11, 2002)	President, The Woodbridge Company Limited
Murray J. Elston ⁽¹⁾⁽⁴⁾ Manotick, Ontario (Director since June 11, 2002)	President, Canada's Research-Based Pharmaceutical Companies
Dr. Murray B. Frum ⁽¹⁾⁽³⁾ Toronto, Ontario (Director since June 11, 2002)	Chair and Chief Executive Officer, Frum Development Group

Don MacKinnon ^{(4) (5)}	President, Power Workers' Union
Chatsworth, Ontario (Director since June 11, 2002)	
Eileen A. Mercier ^{(1) (2)}	Corporate Director
Toronto, Ontario (Director since August 15, 2002)	
Tom Parkinson	President and Chief Executive Officer, Hydro One Inc.
Oakville, Ontario (Director since April 16, 2003)	
Hon. Bob Rae ^{(2) (3) (5)}	Partner, Goodmans LLP
Toronto, Ontario (Director since June 11, 2002)	
Kenneth D. Taylor ^{(4) (5)}	Chair, Taylor and Ryan Inc.
New York, New York USA (Director since June 11, 2002)	
Blake Wallace ^{(2) (3) (5)}	Vice President and Director, Murray & Company
Toronto, Ontario (Director since November 22, 2002)	
Glen Wright ^{(3) (4)}	Chair and President, Workplace Safety and Insurance Board
St. Agatha, Ontario (Director since June 11, 2002)	
Adam Zimmerman ^{(1) (2)}	Corporate Director
Toronto, Ontario (Director since June 11, 2002)	

- (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.

W. Geoffrey Beattie is currently President of The Woodbridge Company Limited, the Thomson family holding company, to which he was appointed in March 1998. He serves on the board of The Thomson Corporation, Bell Globemedia Inc., Royal Bank of Canada and Tm Bioscience Corporation. Mr. Beattie has been a Director of our company since June 11, 2002.

Murray J. Elston was appointed President and CEO of the Canadian Nuclear Association, effective January 5, 2004. He 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.

Dr. Murray B. Frum has served as Chair and CEO of Frum Development Group, since 1972. He is also Chair of the Ontario Arts Council Foundation to which he was appointed in 1998, Chair of the Ontario Cultural Attractions Fund since 1999, and a Governor of Mount Sinai Hospital since 1992. He is a member of several other organizations and was awarded the Order of Canada in 2000. Dr. Frum 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. 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, Quebecor World Inc., ING Bank of Canada, Winpak Limited, Shermag Inc., The University Health Network and York University. Mrs. Mercier has been a Director of our company since August 15, 2002.

Tom Parkinson was appointed the President and Chief Executive Officer of Hydro One Inc. effective 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. Mr. Parkinson is also a member of the Board of Directors of the IMO, representing the transmitter class of stakeholders. Mr. Parkinson is a member of the Board of Directors of the Canadian Electricity Association. 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 Goodmans LLP and is a member of the Board of Directors of public companies and non-profit organizations including Tembec Inc., Trojan Technologies, The Toronto Symphony Orchestra, The Royal Conservatory of Music, Institute for Research in Public Policy, Canadian Unity Council and Forum of Federations. He has been a Director of our company since June

11, 2002. 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.

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 Director for Murray & Company, a financial advisory services company to real estate and public-private partnerships, and has also served as Vice President and General Counsel of the company since 1972. He was the Vice-Chair of TVOntario until June 2003. Mr. Wallace has been a Director of our company since November 22, 2002.

Glen Wright is currently the Chair and President of the Workplace Safety and Insurance Board to which he was appointed Chair in 1996 and appointed President in the spring of 2003. He served as Chair of Hydro One Inc. from June 11, 2002 to May 30, 2003. Mr. Wright also served as Chair of the Cowan Insurance Group Limited and is a Director of PrinterOn Corporation, the Institute for Work and Health, a member of the Wilfrid Laurier University Foundation and a member of the Board of Governors of the Council for Canadian Unity. Mr. Wright has been a Director of our company since June 11, 2002.

Adam Zimmerman is a Fellow of the Institute of Chartered Accountants and has served on over 40 private sector boards during his career. Now retired, his corporate experience includes Chair of the Board of Noranda Forest Inc., and a Director of Noranda Inc., MacMillan Bloedel Limited, Algoma Steel Inc., Celanese Canada Inc., The Pittston Company, Royal Dutch Paper Mills, Maple Leaf Foods Inc., Southam Inc. and The Toronto-Dominion Bank. Mr. Zimmerman was Chairman and Director of Confederation Life Insurance Company when it went into liquidation in August 1994. Mr. Zimmerman was the past Chairman of the Canadian Pulp and Paper Association, the Canadian Forest Industries Council, the C.D. Howe Institute and is an Officer of the Order of Canada. Mr. Zimmerman has been a Director of our company since June 11, 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 senior officers as of February 1, 2003:

<u>Name and Municipality of Residence</u>	<u>Position with our Company</u>
Tom Parkinson	President and Chief Executive Officer
Oakville, Ontario	
Ken Hartwick	Chief Financial Officer and Senior Vice President, Finance
Milton, Ontario	
Laura Formusa	General Counsel and Secretary
Toronto, Ontario	

Tom Parkinson's biographical information is presented above under "Directors".

Ken Hartwick was appointed as Chief Financial Officer and Senior Vice President, Finance in September 2001 after serving as our Senior Vice President, Finance since October 2000. Prior to joining our company, Mr. Hartwick served as Vice President of Cap Gemini Ernst & Young Inc. and as a partner of Ernst & Young LLP.

Laura Formosa 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.

The officers 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.

ADDITIONAL INFORMATION

We will provide to any person or company upon request to the Secretary of Hydro One at 483 Bay Street, 10th Floor, South Tower, Toronto, Ontario, M5G 2P5:

- (a) when the securities of our company are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus;
 - (i) a copy of our latest Annual Information Form, together with a copy of any document, or the pertinent pages of any document, incorporated by reference in the latest Annual Information Form;
 - (ii) a copy of the comparative consolidated financial statements of our company for our most recently completed financial year for which financial statements have been filed, together with the accompanying report of the auditor and a copy of the most recent interim consolidated financial statements of our company that have been filed, if any, for any period after the end of our company's most recently completed financial year;
 - (iii) a copy of any annual filing of our company prepared instead of an information circular; and
 - (iv) a copy of any other documents incorporated by reference into a preliminary short form prospectus or short form prospectus and are not required to be provided under clauses (i), (ii), and (iii) above; or
- (b) at any other time, one copy of any documents referred to in paragraphs (a)(i), (ii) and (iii), provided that we may require the payment of a reasonable charge if the request is made by a person or company who is not a security holder of our company.

As our sole shareholder is the Province, we are not required to prepare an information circular. Information concerning remuneration and indebtedness of directors and senior officers is contained in our annual filing of a reporting issuer. Additional financial information is contained in our audited comparative consolidated financial statements for our most recently completed fiscal year.