HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

This discussion contains forward-looking statements that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. We do not intend to update this information and disclaim any legal obligation to the contrary.

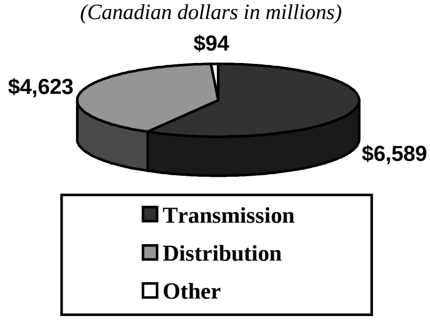
We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2003 and 2002.

OVERVIEW

We are the leading electricity transmitter and distributor in Ontario. We are wholly owned by the province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while providing a good working environment for our employees and creating shareholder value.

Total Assets December 31, 2003

(Canadian dollars in millions)



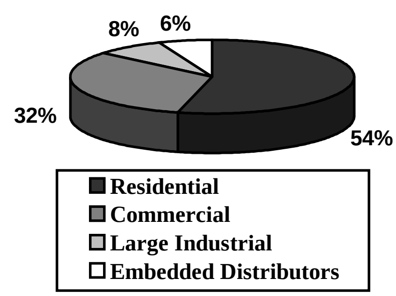
Transmission

We own and operate substantially all of Ontario's electricity transmission system. In 2003, we directly or indirectly transmitted approximately 151.7 TWhs of electricity to over four million customers and earned total revenues of $1,298 million. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can import and export approximately 3,900 MWs and 5,800 MWs of electricity, respectively.

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.2 million rural and urban customers, and 47 large industrial customers. 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. As illustrated in the accompanying chart, the majority of the $2,734 million of distribution revenues which we earned in 2003 was from our residential customers.

2003 Distribution Revenue



Other

Our other business segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc. This subsidiary markets surplus fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. This segment contributed revenues of $26 million in 2003 and has assets of about $94 million, which constitute less than 1% of our total assets.

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.
- *Customer Service:* Become a more customer-focused company. Undertake actions to dramatically improve our customers' level of satisfaction. In particular, 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 largely reinvested into the work programs.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining an effective borrowing capability through stable credit quality and delivering stable financial returns to our shareholder.

Performance Measures and Targets

We measure and target our performance in the above strategic areas and met all of our 2003 targets. In particular, 2003 was characterized by strong financial performance, while making progress towards upgrading our assets and improving reliability through key investments in our transmission and distribution work programs. In addition, we reduced the number of worker lost time injuries and the associated time lost by 50% as compared to 2002 levels.

We believe that by consistently meeting our targets, we will attain our goals. Our safety target for 2004 is to further reduce the number of worker lost time injuries and the associated time lost by 50% as compared to 2003 levels, with a view to creating and maintaining an injury free workplace by 2006. We will measure progress towards our customer service goal through regular customer satisfaction surveys, monitoring compliance with the OEB service quality targets, and timely delivery of customer service improvement initiatives. In particular, we expect to improve customer satisfaction by more promptly resolving customer issues, making it easier to do business with our company and better understanding our customer needs. We will also address service reliability by continuing to invest in our transmission and distribution systems to meet the service levels specified by the OEB for our distribution system, and reviewed with the OEB for our transmission system. We will also address any reliability standards revisions resulting from post-August 14th blackout studies and recommendations. Our financial targets include achieving stable, consistent financial performance; maintaining and then growing our financial results including dividends; and further reducing costs and enhancing productivity while at the same time largely reinvesting the resulting savings into our work programs.

REGULATION

Our electricity transmission and distribution businesses are regulated by the OEB. The OEB sets rates for customers based on the level of revenue required to operate our regulated businesses and our approved rate of return.

Our industry has undergone significant restructuring over the past several years in preparation for the opening of Ontario's wholesale and retail electricity markets to competition on May 1, 2002 (Open Access). Under Open Access, the commodity price of electricity was determined by demand and supply. On December 9, 2002 the Province enacted the *Electricity Pricing, Conservation and Supply Act, 2002* (*Electricity Pricing, Conservation and Supply Act*) which capped transmission and distribution rates and froze the commodity price of electricity for certain low volume and designated consumers at 4.3 cents per kWh, retroactive to Open Access. Other customers continue to pay the Independent Electricity Market Operator's (IMO) spot market price for the commodity, subject to business protection plan rebates from Ontario Power Generation Inc. (OPG).

On December 18, 2003, the Legislative Assembly of Ontario passed *An Act to amend the Ontario Energy Board Act, 1998 with respect to Electricity Pricing* (*Ontario Energy Board Amendment Act*). This Act has yet to be proclaimed. When proclaimed, the rate cap will be lifted and, starting April 1, 2004, customers who qualify for the 4.3-cent commodity price will fall under a new two tiered pricing structure. The fixed commodity price for the first 750 kWh of consumption per month will be 4.7 cents per kWh while consumption in excess of that amount will be billed at 5.5 cents per kWh. Revenue in excess of a distributor's cost of purchased power will be rebated and shortfalls will be funded by the Ontario Electricity Financial Corporation (OEFC). Commencing no later than May 1, 2005, responsibility for setting the commodity price to be paid by retail customers will pass to the OEB, under a process yet to be developed. The *Ontario Energy Board Amendment Act* also provides for the complete restoration of the normal regulatory framework for transmission rates.

Transmission Rates

The IMO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. These rates were set, based on our estimated load, to provide for an annual rate of return of 9.88% on common equity deemed to be allocated to this business. Prior to Open Access, transmission rates were set to provide for an annual rate of return of 9.88% but were collected on a bundled rate basis by OPG and were paid to us based on a revenue allocation agreement.

Distribution Rates

Prior to Open Access, our distribution business purchased power on a fixed-price basis from OPG and charged our distribution customers a bundled rate for the generation, transmission and distribution of electricity. The bundled rates originally set by the OEB provided for an annual rate of return of 9.88% on common equity deemed to be allocated to this business. Commencing with Open Access, we purchase power from the IMO spot market and charge our distribution customers unbundled rates.

The *Electricity Pricing, Conservation and Supply Act* suspended an approved rate increase, which was scheduled to be effective March 1, 2003, to allow local distribution companies in Ontario to achieve a full commercial return of 9.88%. This Act also suspended our approved rate changes associated with low-voltage charges for embedded local distribution companies and direct customers. In a letter dated December 19, 2003, the Minister of Energy stated the intention to allow distributors to make application to the OEB to implement the March 1, 2003 rate increase on March 1, 2005. The rate increase will be conditional on each distributor investing an amount, equal to one year of the incremental revenue, in conservation or demand side management initiatives. We expect this amount to equal approximately $60 million.

Distributors were also granted approval to make rate application to the OEB with regard to rate recovery of certain distribution regulatory assets whose inclusion in rates was delayed by the *Electricity Pricing, Conservation and Supply Act*. These assets primarily include market ready costs, retail settlement variance account balances, and certain environmental costs. We filed a distribution rate application dated January 28, 2004 with the OEB, and as a result we expect that the applicable distribution regulatory assets will be recovered over a four-year period, effective March 1, 2004. The balances to be recovered will be subject to the OEB's approval following their review of the amounts. As a result of the letter received from the Minister of Energy, we anticipate our distribution business returns to improve and approach the full commercial return after 2006.

RESULTS OF OPERATIONS

Revenues

Year ended December31 (Canadian dollars in millions)	**2003**	**2002**	**$ Change**	**% Change**
Transmission	1,298	1,317	(19)	(1)
Distribution	2,734	2,682	52	2
Other	26	32	(6)	(19)
	4,058	4,031	27	1
Transmission - units transmitted *(TWh)*[1]	151.7	153.2	(1.5)	(1)
Distribution - units distributed *(TWh)*[1]	27.9	27.1	0.8	3

[1] System related statistics include preliminary figures for December.

Transmission. We earn transmission revenues based on the peak demand for electricity across our high voltage network. The level of peak demand is primarily influenced by weather conditions. Accordingly, our transmission revenues were lower this year primarily as a result of the abnormally hot temperatures experienced during the summer of 2002. The average peak demand was 2,645 MWs lower during the third quarter of 2003 compared to the same period in 2002. This was partially mitigated by the impact of the colder winter at the beginning of 2003. Transmission revenue also includes a minor amount of non-energy revenue associated with services provided to other industry participants, principally generators.

Distribution. Our distribution revenues include our distribution tariff, recovery for the cost of purchased power used by our customers and ancillary distribution services. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute and the price of purchased power.

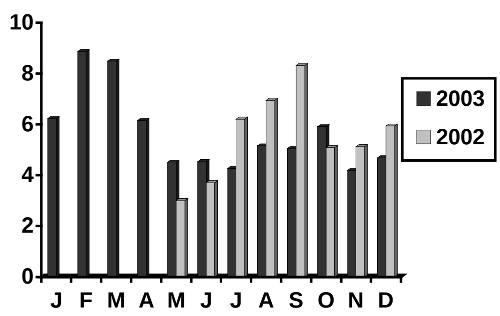
Distribution revenues increased by $126 million due to the addition of a number of large customers that we have directly served since Open Access, as well as higher demand for electricity attributable to the net impact of a colder winter in 2003 partially offset by lower weather-related demand for the remainder of the year. This overall increase attributable to volume was partially offset by a $77 million reduction in distribution revenues related to price changes, primarily reflecting lower purchased power prices as described below, and the impact of increases in our OEB-approved distribution rates. Revenues from ancillary distribution services were also marginally higher this year.

Other. Other revenues declined by $6 million to $26 million in 2003. Revenues due to the growth of our telecommunications business were more than offset by a reduction in revenues attributable to our former energy services business. Effective April 30, 2002, we sold substantially all of the assets of our energy retail operations. See Note 13 to the Consolidated Financial Statements.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service area and consist of the commodity price of electricity, IMO wholesale market service charges and transmission charges levied by the IMO. Since Open Access, as a result of the *Electricity Pricing, Conservation and Supply Act*, the commodity price of electricity has been fixed at 4.3 cents per kWh for certain low volume and designated customers. The commodity price of electricity is based on the Hourly Ontario Energy Price (HOEP) established by the IMO spot market for customers who are not eligible for the fixed price of 4.3 cents per kWh. A comparison of the monthly weighted-average HOEP is shown in the accompanying chart.

Weighted-Average Ontario HOEP
(Cents/kWh)



Purchased power costs increased by $14 million, or less than 1%, to $1,872 million in 2003. Purchased power costs increased by $119 million due to the requirement to directly serve additional customers and the net increase in weather-related consumption. This overall increase attributable to volume was partially offset by a reduction of $105 million related to price changes associated with the unbundling of electricity rates upon Open Access, lower average commodity prices for electricity, and lower average wholesale market service charges. In accordance with the *Electricity Pricing, Conservation and Supply Act,* the IMO wholesale market service charges are fixed at 0.62 cents per kWh, effective December 1, 2002. Previously, from the date of Open Access, these charges were based on market conditions that varied from month to month.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings. The level of work program expenditures, including operation, maintenance and administration and capital costs, is determined through an integrated planning process that prioritizes investments based on strategic priorities and their ability to mitigate business risks.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002[1]**	**$ Change**	**% Change**
Transmission	382	374	8	2
Distribution	387	383	4	1
Other	26	75	(49)	(65)
	795	832	(37)	(4)

[1] Operations, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program. This charge was attributed to the transmission, distribution and other segments as $11 million, $11 million and $3 million, respectively.

Transmission. Costs necessary to sustain our transmission stations, high-voltage lines and rights of way increased by $34 million compared to last year. This increase was primarily due to a larger work program associated with maintaining safety, reliability and environmental standards at our transmission station sites, and increased corrective station maintenance. The higher level of corrective maintenance primarily reflects transformer and other equipment failures. These increased expenditures were partially mitigated by a $26 million reduction in other operating costs incurred in support of our transmission infrastructure. This primarily reflects favourable property tax re-assessments for many of our sites, as well as the charge for the staff reduction program that was recognized in 2002 and the resulting savings achieved from streamlining head office and managerial support functions. Cost savings have been largely reinvested into the maintenance work program.

While we took a lead role to restore power on a priority basis after the August 14th blackout, in which a major loss of electric load occurred in the Mid-west and Northeast US and Eastern Canada, including most of Ontario, our efforts did not result in a significant increase in our costs during 2003. Our protection and control equipment operated effectively through the event and as a result, we experienced minimal damage to our equipment and system infrastructure.

The US-Canada Power System Outage Task Force (Task Force) was established to identify the causes of the August 14th event and to seek recommendations to help prevent future large-scale power outages. The Task Force released a preliminary report in November 2003 on the causes of the blackout, and neither Hydro One nor any other Ontario entities were identified as contributors. The Task Force is now conducting public consultations to seek input and advice in developing its recommendations to prevent future large-scale blackouts. We are participating in these consultations and continue to support associated technical teams established by the North American Electric Reliability Council.

Distribution. Maintenance expenditures incurred on our distribution stations, low-voltage lines and rights of way increased by $37 million compared to last year, primarily due to our expanded forestry maintenance program as well as expenditures associated with emergency trouble calls to restore power. Enhanced vegetation management, including the clearing of overhead power lines and brush control on our rights of way, is being undertaken to maintain safety and reliability on our system by reducing the risk of vegetation-caused power outages. Costs to support our customer care operations that include call handling, bill production, collections and retail settlements, were higher by about $4 million, primarily reflecting the impact of changes associated with the *Electricity Pricing, Conservation and Supply Act*, including last winter's disconnection moratorium and increased call centre resources. The impact of these increases was partially offset by a $37 million reduction in other costs incurred in support of the distribution system. Consistent with transmission, this decrease primarily reflects the charge for the staff reduction program that was recognized in 2002 and the resulting savings achieved from streamlining head office and managerial support functions. Cost savings have been largely reinvested into the maintenance work program.

Other. Other operation, maintenance and administration costs declined by $49 million to $26 million in 2003. Higher costs necessary to support the increased revenue generated by our telecommunications business were more than offset by the absence of costs in 2003 associated with the energy retail operations and lower costs related to our executive office.

Depreciation and Amortization

Depreciation and amortization expense increased by $43 million, or 10%, to $454 million in 2003. This increase primarily results from an increase in fixed assets in service consistent with our capital expenditure program and higher amortization expense associated with a regulatory asset established for certain environmental remediation costs incurred by our distribution business.

Financing Charges

Financing charges declined by $5 million, or 1%, to $348 million in 2003. This reduction reflects the refinancing of our debt at lower average interest rates compared to the rates on the maturing debt. The average level of debt outstanding in 2003 and 2002 was essentially the same.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to OEFC in accordance with the *Electricity Act, 1998* on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our non-regulated businesses.

The provision for payments in lieu of corporate income taxes declined by $40 million, or 17%, to $193 million in 2003. This reduction reflects higher tax deductions, primarily for payments relating to the 2002 staff reduction program and the impact of a reduction in the statutory tax rate from 38.62% to 36.62%. The charge for the staff reduction program was recognized for accounting purposes in 2002, but was deducted for tax purposes in the current year when the related cash payments were made.

Net Income

Net income increased by $52 million, or 15%, to $396 million in 2003. This increase is principally due to the cost reductions realized as a result of the sale of the energy retail operations in April 2002. The effect on net income of larger work programs for our transmission and distribution businesses was substantially offset by the impact of the staff reduction program initiated in 2002 to streamline head office and managerial support functions. The lower provision for payments in lieu of corporate income taxes also contributed to the higher level of net income this year.

Quarterly Results of Operations

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 interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and includes all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2003				2002			
Quarter ended	**Mar. 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**	**Mar 31**	**Jun. 30**	**Sep. 30**	**Dec. 31**
Total revenues[1]	1,147	953	949	1,009	1,022	913	1,097	999
Net income	139	85	93	79	106	99	112	27
Net income to common shareholder	134	81	88	75	101	95	107	23

[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.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, capital market borrowings and bank financing. These resources are used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Operating activities	1,032	492
Financing activities		
Long-term debt issued	1,250	500
Long-term debt retired	(879)	(443)
Short-term notes payable	(554)	169
Dividends paid	(244)	(192)
Investing activities		
Capital expenditures	(597)	(570)
Other financing and investing activities	(10)	33
Net change in cash and cash equivalents	(2)	(11)

Operating Activities

Net cash generated from operations was $1,032 million in 2003, compared with $492 million in 2002. In addition to our stronger financial performance in 2003, we experienced a favourable change in cash flow related to working capital. In 2003, cash flow from working capital increased by $69 million, compared to a decrease of $226 million in 2002. The 2003 increase was largely the result of an increase in accounts payable, mainly due to higher work program activity toward the end of the year, and a reduction in accounts receivable. The 2002 reduction in cash flow from working capital largely resulted from a significant increase in accounts receivable, primarily attributable to a one-time impact associated with Open Access, and a reduction in accounts payable, primarily due to a reduction in energy prices and the timing of payments in lieu of corporate income taxes. Other favourable cash flow impacts include the amortization of the discount associated with a debt restructuring, changes in retail settlement variance account balances, reflecting timing differences between when we pay certain system charges and when they are recovered from customers, and changes in the liability for employee future benefits other than pension, reflecting changes in the interest rate forecast.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. This program is supported by committed revolving credit facilities with a syndicate of banks of $750 million maturing in August 2004 and $250 million maturing in August 2005. The $1 billion in short-term liquidity available under this program and anticipated levels of funding from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our medium term note program. We have approximately $1.5 billion principal amount issuable under this program that is available until July 2005. Our notes and debentures mature between 2004 and 2043. We currently plan to refinance maturing debt principally through our medium term note program.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Rating Services Inc.	A-2	A- (negative outlook)
Dominion Bond Rating Service Inc.[1]	R-1 (low)	A
Moody's Investor Services Inc.[2]	Prime-1	A2

[1] On December 10, 2003, Dominion Bond Rating Services Inc. changed the trend on our long-term debt rating to Stable from Negative and confirmed the long-term and short-term debt ratings.

[2] On December 12, 2003, Moody's Investor Services Inc. confirmed our long-term and short-term debt ratings.

During the first quarter of 2003, we restructured approximately $1.65 billion of debt held by OEFC, which had a weighted-average interest rate of approximately 8.7%, for approximately $1.86 billion of debt, with a weighted-average interest rate of approximately 4.0%. This debt restructuring resulted in lower interest payments during 2003 through to 2007 and a corresponding increase in the principal amount payable at maturity through this period. After restructuring, the net carrying amount of the new notes (principal less unamortized discount) equaled the carrying value of the existing notes prior to renegotiation. The restructuring essentially had no impact on net interest expense for the year. OEFC subsequently sold all of its Hydro One debt into the public markets, and as a result, all of our debt is now publicly traded. As at December 31, 2003, we had long-term debt outstanding of $5,164 million, including the current portion, with a weighted-average interest rate of 5.4%.

During 2003, we issued $1,250 million in long-term debt under our medium term note program and we repaid $879 million in maturing long-term debt. During 2003, we also reduced our outstanding short-term notes payable by $554 million. In 2002, we issued $500 million in long-term debt and we repaid $443 million in maturing long-term debt. In this same period, we increased our short-term notes outstanding by $169 million.

In 2003, we paid dividends to the Province in the amount of $244 million, consisting of $18 million in preferred dividends and $226 million in common dividends. In the comparative period, we paid common and preferred dividends totaling $192 million.

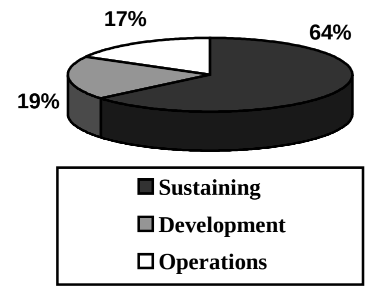
Investing Activities

Cash used in investing activities primarily represents capital expenditures to enhance and reinforce our transmission and distribution systems. Investing activities in 2002 also included net proceeds of approximately $50 million from the sale of substantially all of the assets pertaining to our energy retail operations.

Capital expenditures for each of our three business segments were as follows:

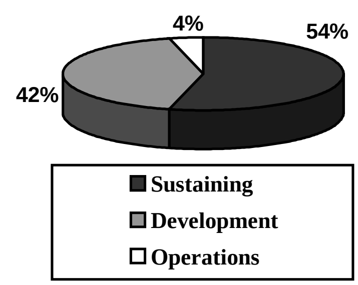
Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**	**$ Change**	**% Change**
Transmission	289	260	29	11
Distribution	292	286	6	2
Other	16	24	(8)	(33)
	597	570	27	5

2003 Transmission Capital Expenditures



Transmission. Capital expenditures for our transmission business were $289 million and $260 million in 2003 and 2002, respectively. Capital expenditures on existing transmission stations, lines, equipment and telecommunications assets increased by $39 million to $184 million in 2003. This increase primarily reflects the incremental replacement of transformers and other station equipment, as well as transportation and work equipment, which have reached the end of their useful service lives. The replacement of our microwave radio system continued through the year. 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. Capital expenditures to expand and reinforce our transmission system were $56 million compared to $51 million in 2002 due to investments to increase capacity, including station construction in Southern Ontario. Capital expenditures supporting transmission operations were $49 million, representing a reduction of $15 million over expenditure levels in 2002. Construction of a consolidated operating centre, which began last year, was completed in 2003. The centre will be fully functional in 2004 and will achieve cost efficiencies, improve customer response, and provide advanced monitoring and analysis capabilities. In addition, investments in information technology were lower due to the completion of a number of projects related to our corporate and asset management systems.

2003 Distribution Capital Expenditures



Distribution. Capital expenditures for our distribution business were $292 million in 2003, compared with $286 million in 2002. Capital expenditures on existing distribution stations, lines and equipment increased by $22 million to $156 million in 2003. This increase primarily reflects the replacement of transportation and work equipment that have reached the end of their useful service lives, and expenditures associated with storm damage and emergency trouble calls to restore power. In total, investments to connect new customers and reinforce our distribution system were substantially the same at $124 million and $122 million in 2003 and 2002, respectively. Capital expenditures necessary to support our distribution operations declined by $18 million to $12 million due to a reduction in information technology investments, primarily due to completion in 2002 of the system and process upgrades required for Open Access.

Other. Capital expenditures primarily for our telecommunications business amounted to $16 million in 2003 compared with $24 million in 2002. Expenditures in 2003 reflect the completion of the fibre-optic network and ongoing equipment upgrades commensurate with the growth in demand. The network now provides lit access to most of Southern and Eastern Ontario with links to Buffalo and Montreal.

Future Capital Expenditures

Our capital expenditures in 2004 are budgeted at about $670 million, an increase of roughly $70 million over our 2003 levels. The budgets for our transmission and distribution businesses are about $365 million and $295 million, respectively. Other capital expenditures are budgeted at $10 million and are largely minor enhancements to our fibre-optic network in support of our telecommunications business. Capital expenditures are expected to stay at the same general level over the next few years.

The transmission and distribution 2004 capital budgets include a number of major development projects to expand our delivery capabilities, which will be completed in future years, as well as ongoing sustainment work which will enable the delivery system to continue to perform at current or improved levels. For instance, our consolidated operating centre will be completed and placed into service in 2004. A prime goal of our 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 lives. 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 station 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. 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 marketplace 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, such as that in Timmins, are being phased out and replaced with current standard, higher voltage equipment. Investments will also be made to address growth on the distribution system.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2003 (Canadian dollars in millions)	**Total**	**2004**	**2005/2006**	**2007/2008**	**After 2008**
Contractual Obligations *(due by year):*					
Short-term notes payable	25	25	-	-	-
Long-term debt	5,164	472	1,237	855	2,600
Inergi LP (Inergi) outsourcing agreement[1]	823	112	212	204	295
Operating lease commitments	26	9	9	5	3
Total Contractual Obligations	6,038	618	1,458	1,064	2,898
Other Commercial Commitments *(by year of expiry)*:					
Bank line[2]	1,000	750	250	-	-
Letters of credit[3]	110	108	2	-	-
Guarantees[3]	275	275	-	-	-
Pension[4]	300	100	200	-	-
Total Other Commercial Commitments	1,685	1,233	452	-	-

[1] On March 1, 2002, Inergi began providing a range of services to us, including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period.

[2] As a backstop to our commercial paper program, we have a revolving standby credit facility with a syndicate of banks of $750 million for a 364-day term maturing on August 13, 2004 and $250 million for a five-year term maturing on August 18, 2005.

[3] We currently have bank letters of credit of $69 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IMO as required by the Market Rules, using a combination of bank letters of credit of $35 million and parental guarantees of $275 million. The amount of prudential support that we provide in the form of bank letters of credit to the IMO is dependent on our long-term credit ratings from major Canadian and U.S. rating agencies. The amount of bank letters of credit provided would need to increase if our credit ratings deteriorated. The remaining letters of credit pertain to operating letters of credit and surety bonds.

[4] Contributions after 2006 will be based on an actuarial valuation as at December 31, 2006 and 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.

Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs. The amounts in the above table under short-term notes payable and long-term debt are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table.

RISK MANAGEMENT

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. The Hydro One Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Financial Officer is responsible for the ongoing monitoring and review of our risk profile and practices and for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Regulatory Risk

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 that for market ready costs, will cease coincident with the commencement of the new recoveries, resulting in 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.

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.

The OEB approves rates for both our transmission and distribution businesses based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements are based on cost assumptions that may not materialize. For example, we may not be able to further improve our labour productivity or reduce our labour costs to the levels assumed in our revenue requirements. Similarly, we may not achieve all of the expected cost reductions in our Inergi agreement, although we believe that our outsourcing arrangement will yield significant cost savings over the term of the agreement. There is no assurance that the OEB would allow rate increases sufficient to offset these impacts.

There is also a risk we could be required to incur unexpected capital expenditures to maintain or improve our transmission and distribution assets and processes. We have no insurance for naturally occurring damage or catastrophe impacting our assets located outside of our transmission and distribution stations.

Pension Risk

As a result of the last actuarial valuation as at December 31, 2000, we have not been required to contribute to the pension plan. We will file a new actuarial valuation as at December 31, 2003 with the Financial Services Commission of Ontario in 2004. We expect to make contributions to the plan commencing in 2004 of approximately $100 million per year, for the next three years. Contributions after 2006 will be based on an actuarial valuation as at December 31, 2006 and 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.

Similarly, the outsourcing agreement with Inergi includes a risk sharing agreement that could involve either our company or Inergi making a payment related to a future imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement will be settled based on data available on December 31, 2004 and will depend on economic factors and pension fund rates of return. If this risk sharing agreement had been settled on December 31, 2003, we would have been required to pay Inergi approximately $20 million.

We have requested approval from the Minister of Energy to apply for 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 pension contributions are made.

Ownership by the Province

The Province owns all of our outstanding shares and therefore controls our company, has the power to determine the composition of our Board of Directors and appoint the Chair, and may directly influence our major corporate decisions and business plans. As such, in making decisions that affect us, the Province can be expected to consider the best interests of all of the residents of Ontario as well as the specific interests of our company and our customers. Examples of areas where this balance must be exercised include structuring and regulating Ontario’s electricity industry, regulating environmental issues and determining the amounts to be paid by us as dividends.

Environmental Risk

We are subject to federal, provincial and municipal environmental regulations that are subject to change. Failure to comply could lead to government orders requiring us to take specific actions or could subject us to fines, penalties, or claims by third parties. Environmental assessments and seeking government approvals for the construction of facilities could result in delays and cost increases.

As a result of expected revisions to Environment Canada’s draft regulations for the management of polychlorinated biphenyls (PCBs), we have reduced our estimated long-term environmental liability and offsetting related regulatory asset by $64 million. There was no impact on our results of operations due to the regulatory accounting treatment of these expenditures. 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.

International scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to relocate some of our facilities, or face difficulties in locating and building new facilities.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses on April 1, 1999 did not result in a transfer of title to some assets located on Indian lands. Under the terms of our transfer orders, OEFC will continue to hold these assets until we receive federal and Indian consents required for title transfer. We expect our annual costs after completion of title transfer to exceed the amounts included in existing revenue requirements. If title transfer cannot be achieved, we expect that either OEFC will continue to hold these assets or we will be required to relocate them, likely at significant expense. Such additional costs could have an adverse effect on our results of operations in the event we were unable to recover them in future rates.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. At the end of 2003, offsetting interest rate swap agreements with the same counter-parties were outstanding with notional principal amounts of $167 million. These agreements mature in 2011. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2004 and 2005 would have an impact on net income of approximately $2 million in 2004 and $5 million in 2005.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives.

Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. With the commencement of Open Access, we are required to procure electricity on behalf of competitive retailers and embedded distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB’s *Retail Settlements Code*.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgments on historical experience, current conditions, and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgments used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2003 amounted to $421 million and principally relate to employee future benefits other than pension, estimated future expenditures required to remediate past environmental contamination, market ready costs, and the retail settlement variance accounts. We have also recorded a regulatory liability pertaining to pension costs. These assets and liability can be recognized for rate-setting and financial reporting purposes only to the extent that the OEB accepts the relevant regulatory treatment. If in a future decision, the OEB subsequently determines that the existing regulatory treatment is no longer acceptable, that regulatory asset or liability would no longer be supportable and, accordingly, would have to be charged or credited to results of operations in the period in which that determination is made.

Employee Future Benefits

We provide employee future benefits to our current and retired employees, including pension, group life insurance, health care, workers' compensation and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). We record employee future benefits other than pension costs on an accrual basis. Both of these costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management with reference to the recommendations of our actuary.

The assumed return on plan assets of 7.25% is based on current expectations of long-term rates of return, and reflects a pension asset mix consistent with the fund’s investment policy of 60% held in listed equity securities and 40% held in corporate and government debt securities. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The weighted-average discount rate is determined by reference to the most recently available market interest rates based on AA corporate bond yields reflecting an average duration of approximately 13 years.

Prior to 2003, declining financial market conditions resulted in the actual rate of return on plan assets being significantly lower than the assumed rate of return. In 2003, the actual rate of return exceeded the assumed rate of return on plan assets. The assumed rate of return continues to reflect our long-term expectations. We believe that this assumption is reasonable because, with the fund’s balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. Interest rates have also declined below our assumed weighted-average discount rate used to calculate the present value of our pension liabilities. We currently estimate that contributions of approximately $100 million per year could be required once our next actuarial valuation is filed, effective December 31, 2003. A 1% reduction in the assumed annual rate of return would result in an increase in 2004 funding requirements of about $2 million.

The costs of employee future benefits other than pension are determined at the beginning of each year, based on an estimate of new claims costs and interest costs on the new and existing claims. Per capita claim costs have been increasing most recently as a result of rising health care cost trends, primarily for prescription drug and extended health care benefits. A 1% increase in the health care cost trends would result in an increase in the benefit cost of about $10 million per year.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2002 subsequent to the enactment of the *Electricity Pricing, Conservation and Supply Act*. As a result of our review, we determined that no impairment of goodwill existed as at December 31, 2002. Given that the passage of the *Ontario Energy Board Amendment Act* is expected to have a positive impact on our future cash flows as compared to those assumed in the 2002 goodwill impairment test, we determined that the probability of our goodwill being impaired is remote.

EMERGING ACCOUNTING PRONOUNCEMENTS

Accounting for Rate Regulated Operations

The Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) has an active project to review generally accepted accounting principles applicable to enterprises with rate regulated operations. Should the AcSB determine that regulatory accounting treatments, which are commonly applied throughout our industry, do not meet the definition of an asset or liability as defined by CICA Handbook Section 1000, we would be required to discontinue the application of rate-regulated accounting. Specifically, we would no longer be able to recognize our regulatory assets and liability, which amounted to $421 million and $584 million, respectively at December 31, 2003. As well, we may be required to account for payments in lieu of corporate income taxes related to our regulated business on a liability basis. The net effect of these changes would be charged to either retained earnings or the results of operations once the new accounting standard became effective, dependent on the transition rules. The AcSB expects to finalize its recommendations and have a final accounting standard in place during 2004. At this time, it is uncertain what decision the AcSB will reach, however we do not believe that the outcome of this CICA project will have a materially adverse financial impact on our company.

Asset Retirement Obligations

We have early adopted the disclosure provisions of the CICA's new Handbook Section 3110, *Asset Retirement Obligations*. This accounting pronouncement requires that enterprises recognize a liability where a legal commitment has been incurred to remove in-service fixed assets at some future date. If they are not replaced, some of our transmission and distribution assets are expected to trigger asset retirement obligations once they are removed. While some of our assets will have future asset retirement obligations, no obligations have been recognized upon the adoption of this accounting standard. We have determined that the date of final removal of our assets that carry asset retirement obligations cannot be reasonably determined at this time. We would recognize an obligation and offsetting capital asset when the amount can be reasonably estimated. Any potential impact on our financial position is not expected to be material.

Employee Future Benefits

We have early adopted the additional disclosures approved by the CICA, amending the Handbook Section 3461, *Employee Future Benefits.* Additional disclosures provided include a description of the type of plan, the date used to measure the plan's assets and the benefit obligations, the effective date of the last actuarial funding valuation, the actual allocation of the plan's assets by major category, and separate disclosure of the discount rate used to determine the net benefit cost and that used to determine the accrued benefit obligation.

OUTLOOK

We will continue to focus on our core work programs, making significant investments to improve asset condition, reliability risk and customer satisfaction. Key investment areas include our vegetation management program where we are striving to increase our cutting frequencies and our asset replacement programs where we are actively managing end of life replacements. Investments in these areas should result in our attaining the level of reliability and service quality required to improve customer satisfaction and our continued achievement of regulatory requirements.

We have also been actively providing input into the long-term transmission needs of Ontario and will work cooperatively to implement necessary new requirements and changes. In particular, investments will be required in the longer term for a variety of major transmission capital initiatives, including area supply improvements in the greater Toronto and Windsor areas. In addition, other reinforcement projects, such as that in the Niagara region, to support increased generation and transmission capability are under consideration.

The need for system expansion to support new supply from Manitoba Hydro has also been identified. Bringing electricity supply from the northern region of Manitoba represents an extensive undertaking that would take close to a decade to complete. We will consult with all of our stakeholders before initiating necessary actions.

There are a number of ongoing investigations that are being undertaken by the Task Force established to examine the August 14th blackout. We are participating in a number of the activities that are underway by the Task Force. Transmission investments over and above those currently planned may be required as a result of the Task Force's recommendations to prevent future large-scale blackouts.

There continues to be approximately 90 local distribution companies in Ontario. We will be an active participant in the OEB's consultation process to review approaches to improve efficiencies and determine benefits of further consolidation of Ontario's electricity distribution sector. We may acquire and sell assets in order to facilitate the rational restructuring of this sector. We will consider such transactions where we can realize economic benefits.

Given recent developments, we anticipate that the financial position of our distribution business will improve. However, the resulting increase in rates will not be sufficient to allow us to earn the regulated return of 9.88% until sometime after 2006. We will continue to work with the OEB and the Province to develop a transmission and distribution rate plan to fund ongoing expansion and strengthening of the network while supporting appropriate commercial returns.

Through this period, we believe that our financial returns will be sufficient to maintain a strong financial condition, current credit quality and current credit ratings on our long-term debt.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) are the responsibility of management and have been prepared in accordance with accounting principles generally accepted in Canada. Hydro One applies accounting principles appropriate to its circumstances. The significant accounting policies followed by the Company are described in the summary of significant accounting policies contained in Note 2 to the Consolidated Financial Statements. The preparation of financial statements necessarily involves the use of estimates based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. The Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and in light of information available up to February 11, 2004.

Management maintains a system of internal controls designed to provide reasonable assurance that the assets are safeguarded and that reliable financial information is available on a timely basis. The system includes formal policies and procedures and an organizational structure that provides for appropriate delegation of authority and segregation of responsibilities. An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with generally accepted accounting principles. The Auditors' Report, which appears on page 19, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

On behalf of Hydro One Inc.'s Management:

Tom Parkinson President and Chief Executive Officer	Ken Hartwick Chief Financial Officer

HYDRO ONE INC.
AUDITORS' REPORT

To the Shareholder of Hydro One Inc.:

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2003 and December 31, 2002, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and December 31, 2002, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2003, in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 11, 2004

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Revenues		
Transmission *(Note 15)*	1,298	1,317
Distribution *(Note 15)*	2,734	2,682
Other	26	32
	4,058	4,031
Costs		
Purchased power *(Note 15)*	1,872	1,858
Operation, maintenance and administration *(Note 12)*	795	832
Depreciation and amortization *(Note 3)*	454	411
	3,121	3,101
Income before financing charges and provision for payments in lieu of corporate income taxes	937	930
Financing charges *(Notes 4 and 15)*	348	353
Income before provision for payments in lieu of corporate income taxes	589	577
Provision for payments in lieu of corporate income taxes *(Notes 5 and 15)*	193	233
Net income	396	344
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 14)*	3,779	3,258

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Retained earnings, January 1	502	357
Net income	396	344
Dividends *(Note 14)*	(244)	(192)
Distribution to shareholder *(Note 6)*	-	(7)
Retained earnings, December 31	654	502

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2003**	**2002**
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $18 million; 2002 - $16 million)	616	646
Materials and supplies	45	55
	661	701
Fixed assets *(Note 6)*:		
Fixed assets in service	14,362	13,790
Less: accumulated depreciation	5,175	4,859
	9,187	8,931
Construction in progress	278	300
	9,465	9,231
Other long-term assets:		
Deferred pension asset *(Note 10)*	584	742
Regulatory assets *(Note 7)*	421	570
Goodwill	133	133
Long-term accounts receivable and other assets	20	28
Deferred debt costs	22	17
	1,180	1,490
Total assets	11,306	11,422

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	**2003**	**2002**
Liabilities		
Current liabilities:		
Bank indebtedness	37	35
Accounts payable and accrued charges *(Note 15)*	620	576
Accrued interest	38	53
Short-term notes payable *(Note 8)*	25	579
Long-term debt payable within one year *(Note 8)*	472	651
	1,192	1,894
Long-term debt *(Note 8)*	4,539	3,938
Other long-term liabilities:		
Regulatory liability *(Note 7)*	584	742
Employee future benefits other than pension *(Note 10)*	597	540
Environmental liabilities *(Note 11)*	69	140
Long-term accounts payable and accrued charges	34	29
	1,284	1,451
Total liabilities	7,015	7,283
Contingencies and commitments *(Notes 9, 17 and 18)*		
Shareholder's equity *(Note 14)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	654	502
Total shareholder's equity	4,291	4,139
Total liabilities and shareholder's equity	11,306	11,422

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

R. Burak

Rita Burak
Chair

Eileen Mercier
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Operating activities		
Net income	396	344
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	417	384
Amortization of discount	60	-
Retail settlement variance accounts	21	(36)
	894	692
Changes in non-cash balances related to operations *(Note 16)*	138	(200)
Net cash from operations	1,032	492
Financing activities		
Long-term debt:		
Issued	1,250	500
Retired	(879)	(443)
Termination of forward sale	(12)	-
Short-term notes payable	(554)	169
Dividends paid	(244)	(192)
Deferred debt costs	(1)	6
Net cash (used in) from financing activities	(440)	40
Investing activities		
Fixed assets	(597)	(570)
Proceeds from disposition *(Note 13)*	-	50
Other assets	3	(23)
Net cash used in investing activities	(594)	(543)
Net change in cash and cash equivalents	(2)	(11)
Cash and cash equivalents, January 1	(35)	(24)
Cash and cash equivalents, December 31 *(Note 16)*	(37)	(35)

See accompanying notes to Consolidated Financial Statements.

1. INCORPORATION AND COMMENCEMENT OF OPERATIONS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc. (Hydro One Brampton), Hydro One Markets Inc., Hydro One Telecom Inc. and Hydro One Delivery Services Company Inc.

Effective January 1, 2003, Hydro One Networks and Hydro One Network Services were combined. Hydro One Network Services as well as the former Ontario Hydro Energy will be dissolved pursuant to the *Business Corporations Act* (Ontario).

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-setting

Our electricity transmission and distribution businesses are subject to rate regulation by the OEB. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets primarily represent costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded a regulatory liability related to pension costs to reflect the fact that revenue and expenses are recognized in the financial statements in different periods consistent with their inclusion in rates, as directed by the regulator, than would be the case for an enterprise that is unregulated. Specific regulatory assets and liability recognized at December 31, 2003 are disclosed in Note 7.

In a letter dated December 19, 2003, the Minister of Energy granted approval for distributors to make application to the OEB with regard to rate recovery of certain distribution regulatory assets whose inclusion in rates was delayed by the *Electricity Pricing, Conservation and Supply Act, 2002* (*Electricity Pricing, Conservation and Supply Act).* As a result of the Company's distribution rate application dated January 28, 2004, these distribution regulatory assets are expected to be recovered over a four-year period, effective March 1, 2004. However, the amount to be recovered will be subject to a yet to be determined OEB review and approval process, expected to occur later in 2004.

The Company continually assesses the likelihood of recovery of each of its regulatory assets and believes that it is probable that its regulatory assets and liability will be factored into the setting of future rates. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Revenue Recognition and Allocation

Prior to the opening of the electricity market to competition on May 1, 2002 (Open Access), transmission revenue was collected through a revenue allocation agreement between the successor companies of Ontario Hydro. Under the agreement, Hydro One received a fixed monthly amount based on an annual revenue requirement approved by the OEB of $1.2 billion. Commencing with Open Access, transmission revenues are collected through OEB-approved unbundled rates, based on the same revenue requirement, and are recognized as power is delivered to customers.

Prior to Open Access, distribution revenues attributable to the sale and delivery of electricity were based on OEB-approved bundled rates. Since Open Access, distribution revenues are based on OEB-approved unbundled distribution rates and are recognized as power is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2003 amounted to $286 million (2002 - $248 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which, prior to Open Access, was collected through the revenue allocation agreement and was recognized in accordance with the terms of the agreement. Commencing with Open Access, rural rate protection amounts are received from the Independent Electricity Market Operator (IMO) based on a standardized customer rate approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

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

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost, which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

During 2003, Hydro One adopted the Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3110, *Asset Retirement Obligations*. This new accounting standard requires the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated fixed asset.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2003 – 7.4%; 2002 – 8.1%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Transmission	12 - 100	57
Distribution	15 - 75	41
Communication	7 - 40	21
Administration and service	5 - 50	42

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation, as defined in CICA Handbook Section 3110, has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased.

Effective January 1, 2002, Hydro One adopted CICA Handbook Section 3062, *Goodwill and Other Intangible Assets.* Under this accounting standard, goodwill is not amortized. The carrying value of goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require, with any write-down of the carrying value of goodwill being charged against the results of operations. Prior to the current standard, goodwill impairment was assessed based on estimated future undiscounted cash flows for the business to which the goodwill relates. Under CICA 3062, goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized over the period to maturity of the debt on an annuity basis.

Discounts, Premiums and Hedging

Discounts, premiums and hedging gains and losses are amortized over the period of the related debt and are presented net of long-term debt.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care, workers' compensation and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Actuarial valuations are conducted at least every three years.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

During 2003, Hydro One adopted the CICA's approved additional disclosures amending Handbook Section 3461, *Employee Future Benefits*. Additional disclosures provided include a description of the type of plan, the date used to measure the plan's assets and the benefit obligations, the effective date of the last actuarial funding valuation, the actual allocation of the plan's assets by major category and separate disclosure of the discount rate used to determine the net benefit cost and that used to determine the accrued benefit obligation.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers (see Notes 7 and 11). Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Depreciation of fixed assets in service	339	327
Fixed asset removal costs	37	27
Amortization of regulatory and other assets	78	57
	454	411

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Interest on short-term notes payable	6	15
Interest on long-term debt payable	306	358
Amortization of discount *(Note 8)*	60	-
Other	3	8
Less: Interest capitalized on construction in progress	(20)	(19)
Interest capitalized on regulatory assets *(Note 7)*	-	(6)
Interest earned on investments	(7)	(3)
	348	353

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Income before provision for PILs	589	577
Federal and Ontario statutory income tax rate	36.62%	38.62%
Provision for PILs at statutory rate	216	223
(Decrease) increase resulting from:		
Net temporary differences:		
Capital cost allowance in excess of depreciation and amortization	(16)	(27)
Environmental expenditures	(8)	(10)
Interest capitalized for accounting purposes but deducted for tax purposes	(7)	(9)
Employee future benefits other than pension expense in excess of cash payments	9	11
Charge for staff reduction program (lower than) in excess of cash payments	(9)	9
Other	(10)	9
Net temporary differences	(41)	(17)
Permanent differences:		
Large corporations tax	17	17
Other	1	10
Net permanent differences	18	27
Provision for PILs	193	233
Effective income tax rate	32.77%	40.38%

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2003, future income tax liabilities of $171 million (2002 - $132 million), based on substantively enacted income tax rates, have not been recorded.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2003				
Transmission	7,609	2,635	193	5,167
Distribution	4,828	1,817	61	3,072
Communication	645	273	15	387
Administration and service	790	394	9	405
Easements	490	56	-	434
	14,362	5,175	278	9,465
2002				
Transmission	7,487	2,487	180	5,180
Distribution	4,619	1,704	50	2,965
Communication	531	237	33	327
Administration and service	663	378	37	322
Easements	490	53	-	437
	13,790	4,859	300	9,231

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $20 million in 2003 (2002 - $19 million).

In circumstances where external customers are required to make specific contributions to fund the construction and installation of specific fixed assets, Hydro One nets the customer contributions against the acquisition cost. Cumulative customer contributions in aid of construction received by Hydro One, net of amortization, except for Hydro One Brampton, were $62 million (2002 - $59 million) for transmission and $263 million (2002 - $243 million) for distribution. Hydro One's subsidiary, Hydro One Brampton, consistent with other Ontario local distribution companies, recorded contributions in aid of construction received prior to January 1, 2000 within fixed assets on a gross basis and depreciates these amounts over the remaining service lives of the assets.

On June 27, 2002, the Legislative Assembly of Ontario passed the *Reliable Energy and Consumer Protection Act, 2002* that amends several statutes relating to Ontario's energy sector, including the ownership and use of corridor land. Corridor land includes land in Ontario owned by Hydro One that was used or acquired for the purposes of the transmission system, including any abutting land. Under this Act, ownership of all corridor and abutting land was transferred to the Province and Hydro One was given a statutory easement in perpetuity to use the land to operate the transmission system. The Company retains the obligation to incur certain ongoing expenditures related to 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.

The transfer of the corridor land was effective December 31, 2002, resulting in ownership of transmission corridors and abutting lands with a net book value of approximately $259 million being transferred to the Province in exchange for a statutory easement in perpetuity asset. In addition, ownership of land assets with a net book value of approximately $7 million, not currently in use, was transferred to the Province and applied as a reduction of shareholder's equity.

7. REGULATORY ASSETS AND LIABILITY

Regulatory assets and liabilities arise as a result of the rate-making process. As described in Note 2, Hydro One has recorded the following regulatory assets and liability:

December 31 (Canadian dollars in millions)	**2003**	**2002**
Regulatory assets:		
Employee future benefits other than pension	209	251
Environmental	118	199
Market ready	55	66
Retail settlement variance accounts	15	36
Other	24	18
Total regulatory assets	421	570
Regulatory liability:		
Deferred pension	584	742
Total regulatory liability	584	742

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset in the original amount of $419 million to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 5 years (2002 - 6 years) and does not earn a return.

Hydro One provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are recoverable through rates, the Company recorded a regulatory asset in the original amount of $190 million. With the exception of that portion of the regulatory asset that relates to certain distribution expenditures, this regulatory asset, including future interest accretion, is expected to be amortized over the period to 2030 (2002 – 2020) on a basis substantially consistent with the pattern of actual expenditures.

Environment Canada has issued draft regulations on managing PCBs. These regulations, which the Company has determined are highly probable to be adopted, allow companies to manage potentially contaminated pole-top transformers on an attrition basis, as they are withdrawn from service at the end of their normal operating lives. Previously, the estimated future expenditures were based on a proactive inspection, testing and removal program for PCB contaminated transformers, consistent with Environment Canada guidance. Due to this change, the Company has revised downward its estimate of the future expenditures required to manage legacy environmental issues, including PCBs, and has reduced its environmental obligation and offsetting regulatory asset by $64 million (see Note 11).

As a result of the Company’s distribution rate application dated January 28, 2004, that portion of the regulatory asset related to the actual distribution environmental expenditures incurred in 2001 and 2002 in the original amount of $39 million is expected to be amortized to results of operations on a straight-line basis over the four year period ending in 2007. Previously this amount was to be amortized over the period 2003 to 2020, inclusive. The OEB has the discretion to examine and assess the extent and timing of recovery of Hydro One’s environmental costs.

Market ready costs have been deferred in accordance with the criteria set out in the OEB’s Electricity Distribution Rate Handbook, the Accounting Procedures Handbook and in subsequent OEB guidelines. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP. As a result of the Company’s distribution rate application dated January 28, 2004, this regulatory asset is expected to be primarily recovered over a four-year period effective March 1, 2004, subject to a prudency review by the OEB.

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB’s Accounting Procedures Handbook. As a result of the Company’s distribution rate application dated January 28, 2004, this regulatory asset is expected to be recovered over a four-year period effective March 1, 2004, subject to a potential audit by the OEB.

Hydro One ceased adding interest to the deferral accounts for market ready costs and the retail settlement variance accounts as at December 1, 2002 for external financial reporting purposes. Hydro One intends to seek recovery of these interest amounts relating to the period after December 1, 2002 in future rate applications.

8. DEBT

December 31 (Canadian dollars in millions)	**2003**	**2002**
Short-term notes payable	25	579
Long-term debt:		
Notes payable to OEFC	-	2,529
3.40% notes due 2004	235	-
3.45% notes due 2004	237	-
6.94% debentures due 2005	200	200
4.00% notes due 2005	339	-
4.10% notes due 2006	109	-
4.15% notes due 2006	280	-
4.20% notes due 2006	168	-
4.30% notes due 2006	141	-
4.45% notes due 2007	282	-
4.55% notes due 2007	73	-
4.00% notes due 2008	500	-
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	300
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	200	-
6.59% notes due 2043	250	-
	5,164	4,579
Less: Long-term debt payable within one year	(472)	(651)
Net unamortized (discounts) premiums	(144)	10
Unamortized hedging losses	(9)	-
Long-term debt	4,539	3,938

Short-term debt represents promissory notes issued pursuant to the Company’s commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days and with a weighted-average interest rate of 2.7% (2002 - 2.9%).

Hydro One has committed and unused revolving credit agreements with a syndicate of banks in the amount of $750 million maturing in August, 2004 and $250 million maturing in August, 2005. If used, interest on the lines of credit would apply based on Canadian benchmark rates. These credit agreements support the Company's commercial paper program.

As at December 31, 2002, the Company had notes payable to OEFC denominated in Canadian dollars with various maturity dates between 2003 and 2007, and with a weighted-average interest rate of 8.2%. On February 20, 2003, Hydro One restructured approximately $1.65 billion of debt held by OEFC, which had a weighted-average interest rate of approximately 8.7%, for approximately $1.86 billion of debt, with a weighted-average interest rate of approximately 4.0%. This debt restructuring resulted in lower interest payments during 2003 through to 2007 and a corresponding increase in the principal amount of the debt payable at maturity through this period. The maturity dates remained essentially unchanged. The restructuring was treated as a renegotiation of debt, with no gain or loss being recognized. Subsequent to the restructuring, OEFC sold its Hydro One debt into public markets and as a result, at December 31, 2003, the Company’s debt is all publicly traded.

The Company also issues notes for long-term financing under the medium term note program. The maximum authorized principal amount of medium term notes issuable under this program is $2.0 billion of which $1.5 billion is remaining and is currently available until July 2005.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2003, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Per cent)*
1 year	472	3.4
2 years	539	5.1
3 years	698	4.2
4 years	355	4.5
5 years	500	4.0
	2,564	4.2
6 – 10 years	1,250	6.3
Over 10 years	1,350	6.9
	5,164	5.4

During 2003, the Company terminated its April 2003 forward sale agreement of $250 million in Government of Canada bonds for a net cash payment of $12 million. This agreement was designated as an interest rate hedge for an anticipated transaction and as a result, the cost of termination was deferred and is being amortized on an annuity basis over the five-year term of the related debt.

9. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of long-term debt, based on year-end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	**2003**		**2002**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	5,164	5,466	4,579	4,925

[1] The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into forward pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. When the hedged borrowing occurs, Hydro One terminates the hedge either by terminating the interest rate swap or by entering into an offsetting swap agreement. As at December 31, 2003, offsetting interest rate swap agreements were outstanding with the same counter-party having notional principal amounts of $167 million (2002 - $167 million) and a fair value of $nil (2002 - $nil). The swap agreements mature in 2011.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2003, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any single customer. As at December 31, 2003, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

10. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund.

Plan Allocation

Hydro One's pension plan asset allocation at December 31, 2003 and 2002 was as follows:

	% of Plan Assets	
December 31	**2003**	**2002**
Equity securities	59.5	53.8
Debt securities	37.3	36.6
Other	3.2	9.6
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities in the Province of $78 million and $41 million at December 31, 2003 and 2002, respectively.

The Company's plan provides benefits based on highest three-year average pension earnings. After retirement, pensions are fully indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation to be filed for December 31, 2003, Hydro One expects to contribute approximately $100 million to its pension plan in each of 2004, 2005 and 2006, all of which is required to satisfy minimum funding requirements. All of the contributions are expected to be in the form of cash. The Company has not been required to contribute to the pension plan because the contribution level, which was established from the last actuarial valuation at December 31, 2000, indicated that the plan had a surplus.

Employees of Hydro One Brampton participate in the OMERS, a multi-employer public sector pension fund, which is a defined benefit plan. As Hydro One Brampton has been under a contribution holiday since August 1998, no contributions have been made to the pension fund. Effective January 1, 2003, Hydro One Brampton commenced contributing to OMERS. Contributions by Hydro One Brampton are estimated to be less than $1 million annually.

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**	**2003**	**2002**
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	4,114	4,166	820	687
Current service cost	69	65	23	20
Interest cost	264	266	52	43
Benefits paid	(238)	(230)	(35)	(32)
Plan amendments	11	-	-	-
Agreement with Inergi LP[1]	-	(127)	-	-
Net actuarial loss (gain)	103	(26)	37	102
Accrued benefit obligation, December 31	4,323	4,114	897	820
Change in plan assets				
Fair value of plan assets, January 1	3,607	4,120	-	-
Actual return on plan assets	562	(164)	-	-
Benefits paid	(238)	(230)	-	-
Employees' contributions	14	16	-	-
Agreement with Inergi LP[1]	-	(127)	-	-
Administrative expenses	(6)	(8)	-	-
Fair value of plan assets, December 31	3,939	3,607	-	-
Funded status				
(Unfunded benefit obligation)	(384)	(507)	(897)	(820)
Unamortized net actuarial losses	940	1,230	262	244
Unamortized past service costs	28	19	7	5
Deferred pension asset (accrued benefit liability)	584	742	(628)	(571)
Less: current portion	-	-	31	31
Deferred pension asset (long-term liability)	584	742	(597)	(540)

[1] The reduction in the accrued benefit obligation and plan assets relates to employees transferred to Inergi LP effective March 1, 2002 (see Note 18). Once the approval by the Financial Services Commission of Ontario is obtained, the Hydro One Pension Plan is expected to transfer assets and liabilities to the Inergi Pension Plan.

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**	**2003**	**2002**
Components of net periodic benefit cost				
Current service cost, net of employee contributions	55	49	23	20
Interest cost	264	266	52	43
Expected return on plan assets	(259)	(285)	-	-
Amortization of net actuarial losses	96	73	16	7
Amortization of past service costs	2	2	1	1
Net periodic benefit cost[2]	158	105	92	71
Capitalized as part of the cost of fixed assets	-	-	37	28
Charged to results of operations	-	-	55	43
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	123	104
Net periodic benefit cost	-	-	10	7
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	(110)	(87)
Net periodic benefit cost	-	-	(8)	(5)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	7.25%	7.25%	-	-
Weighted-average discount rate	6.50%	6.50%	6.67%	6.67%
Rate of compensation scale escalation (without merit)	3.50%	3.50%	3.50%	3.50%
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%
Average remaining service life of employees (years)	12	12	12	12
Rate of increase in long-term medical costs[3]	-	-	4.50%	4.50%
Rate of increase in dental costs[4]	-	-	4.50%	4.50%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	6.00%	6.50%	6.18%	6.67%
Rate of compensation scale escalation (without merit)	3.25%	3.50%	3.25%	3.50%
Rate of cost of living increase	2.25%	2.50%	2.25%	2.50%
Rate of increase in long-term medical costs[5]	-	-	4.50%	4.50%
Rate of increase in dental costs[6]	-	-	4.50%	4.50%

[2] No pension expense was recorded in 2003 and 2002 since the Company follows the cash basis of accounting.

[3] 14.10% per annum in 2003 grading down to 4.50% per annum in and after 2014 (2002 – 15.00% grading down to 4.50% after twelve years).

[4] 7.30% per annum in 2003 grading down to 4.5% per annum in and after 2007 (2002 – 8.00% grading down to 4.50% after five years).

[5] 13.30% per annum in 2004 grading down to 4.50% per annum in and after 2014 (2002 – 14.10% grading down to 4.50% after eleven years).

[6] 6.70% per annum in 2004 grading down to 4.50% per annum in and after 2007 (2002 – 7.30% grading down to 4.50% after four years).

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2003**	**2002**
Environmental liabilities, January 1	160	174
Interest accretion	8	9
Expenditures	(21)	(23)
Revaluation adjustment *(Note 7)*	(64)	-
Environmental liabilities, December 31	83	160
Less: current portion	(14)	(20)
	69	140

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2003 and in total thereafter are as follows: 2004 - $14 million; 2005 - $13 million; 2006 - $12 million; 2007 - $11 million; 2008 - $10 million; and thereafter - $46 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

12. OPERATION, MAINTENANCE AND ADMINISTRATION

In September 2002, Hydro One announced that staff levels would be reduced by approximately 140 employees, primarily from head office and managerial support functions. Hydro One achieved this reduction in 2002 using voluntary and involuntary measures, including those available under collective agreements for some of the affected employees. A provision of $25 million was charged to 2002 results of operations for the estimated future expenditures of achieving this staff reduction. A total of $20 million of this amount was charged to the provision in 2003 (2002 - $2 million), with the remaining amount expected to be charged in 2004.

13. SALE OF ENERGY RETAIL OPERATIONS

Effective April 30, 2002, the Company sold substantially all of the assets pertaining to the energy retail operations of the former Ontario Hydro Energy for net proceeds of approximately $50 million. The sale resulted in an initial estimated gain of $2 million before provision for payments in lieu of corporate income taxes. Under the sales agreement, a final adjustment to the purchase price occurred, reducing the gain on sale before provision for payments in lieu of corporate income taxes to $1 million.

14. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25.00 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2003, preferred dividends in the amount of $18 million (2002 - $18 million) and common dividends in the amount of $226 million (2002 - $174 million) were declared.

Earnings per Share

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

15. RELATED PARTY TRANSACTIONS

The Province, OEFC, IMO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. Transactions between these parties and Hydro One were as follows:

Prior to Open Access, Hydro One received revenue for transmission services consistent with the revenue allocation agreement (see Note 2). Commencing with Open Access, Hydro One receives such revenue from customer revenue collected by the IMO. Transmission revenue for 2003 includes $1,255 million (2002 - $1,269 million) related to these services.

Prior to Open Access, Hydro One received a portion of its distribution revenue consistent with the revenue allocation agreement (see Note 2). Under this agreement, distribution revenue for 2003 includes $nil related to these services (2002 - $10 million).

Prior to Open Access, Hydro One also received revenue related to the supply of electricity to remote northern communities consistent with the revenue allocation agreement (see Note 2). Commencing with Open Access, Hydro One receives such revenue from customer revenue collected by the IMO. Distribution revenue for 2003 includes $21 million (2002 - $21 million) related to these services.

Hydro One receives amounts for rural rate protection from customer revenue collected by the IMO (see Note 2). Distribution revenue for 2003 includes $127 million (2002 - $127 million) related to this program, of which $1 million (2002 - $3 million) was paid to local distribution companies in respect of annexation agreements.

Hydro One purchased power from the IMO administered spot market (from OPG prior to Open Access) in the amount of $1,872 million in 2003 (2002 - $1,857 million).

Hydro One has several service level agreements with the other successor corporations, primarily OPG. These services include field and engineering, logistics, corporate and telecommunications services. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in 2003 and 2002. Revenues related to the provision of services to the other successor corporations are summarized in the following table:

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Revenues		
Transmission	13	12
Distribution	-	2
	13	14

As at December 31, 2003, long-term debt in the amount of $nil million (2002 - $2,529 million) was due to OEFC. Financing charges for 2003 include interest expense on this debt in the amount of $38 million (2002 - $240 million) (see Note 8).

The provision for payments in lieu of corporate income taxes was paid or payable to OEFC and dividends were paid or payable to the Province (see Note 2).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2003**	**2002**
Accounts receivable	112	118
Accounts payable and accrued charges	(195)	(156)

Included in accounts payable and accrued charges are amounts owing to the IMO in respect of power purchases of $149 million (2002 - $143 million).

16. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the consolidated statements of cash flows, “cash and cash equivalents” refers to the balance sheet item “bank indebtedness.”

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**
Accounts receivable decrease (increase)	30	(108)
Materials and supplies decrease	10	1
Accounts payable and accrued charges increase (decrease)	44	(115)
Accrued interest (decrease)	(15)	(4)
Long-term accounts payable and accrued charges increase	5	11
Employee future benefits other than pension increase	57	30
Other	7	(15)
	138	(200)

Supplementary information:		
Interest paid	333	379
Payments in lieu of corporate income taxes	199	294

17. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have an adverse effect on the Company’s consolidated financial position, results of operations or cash flows.

As a result of Hydro One's acquisition of certain transmission, distribution and energy services assets, liabilities, rights and obligations of Ontario Hydro, Hydro One has succeeded Ontario Hydro as a party in a number of legal proceedings. On September 1, 1995, Torcom Communications Inc. (Torcom) named Ontario Hydro as one of several defendants in a suit seeking damages of $150 million, as well as specific performance of certain agreements and interim injunctive relief. Torcom had sought to purchase certain telecommunication devices belonging to a bankrupt company from the court-appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995, when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not yet served a statement of defence. Hydro One believes that there are strong defences to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of the litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty, and compensation for costs incurred in the course of prior negotiations of band grievances with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. To date, Hydro One has not filed a defence. The Company has requested particulars and further and better particulars of the claims, as did the other defendants. As a result of the particulars filed, the Attorney General for Canada brought various motions, which the Company supported, to strike out various claims and for better responses to the particular demands. In September 2003, the Court struck out the claims with leave to amend. The Whitesand Band has now amended its claim and there may be further procedural motions before the Company files a defence. Additionally, this case was consolidated with the Red Rock case noted below. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

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, OEFC, OPG and Hydro One. 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 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 motions in this case before the Company files a defence. Hydro One 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 believes that such a result is unlikely.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial, or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. In such cases, Hydro One would apply to recover these costs in future rate orders.

Pension Risk

As a result of the last actuarial valuation as at December 31, 2000, Hydro One has not been required to contribute to the pension plan. The Company will file a new actuarial valuation as at December 31, 2003 with the Financial Services Commission of Ontario in 2004. The Company expects to make contributions to the plan commencing in 2004 of approximately $100 million per year, for the next three years. Contributions after 2006 will be based on an actuarial valuation as at December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Should financial market conditions improve significantly before December 31, 2006, the Company has the option to file an earlier actuarial valuation.

Similarly, the outsourcing agreement with Inergi LP (Inergi) includes a risk sharing agreement that could involve either Hydro One or Inergi making a payment related to a future imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement will be settled based on data available on December 31, 2004 and will depend on economic factors and pension fund rates of return. If this risk sharing agreement had been settled on December 31, 2003, Hydro One would have been required to pay Inergi approximately $20 million.

The Company has requested approval from the Minister of Energy to apply for recovery of any increased ongoing expenses related to pension costs through future rate applications for the transmission and distribution businesses. This request is under consideration, however the Company has 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 pension contributions are made.

18. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Ernst & Young Canada began providing services to Hydro One through Inergi LP (Inergi). As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period. The initial service level price ranges between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2003, and in total thereafter are as follows: 2004 - $112 million; 2005 - $107 million; 2006 - $105 million, 2007 - $104 million; 2008 - $100 million; and thereafter - $295 million.

Prudential Support

Purchasers of electricity in Ontario, through the IMO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IMO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IMO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2003, the Company provided prudential support, using a combination of bank letters of credit of $35 million (2002 - $50 million) and parental guarantees of $275 million (2002 - $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2003, Hydro One had bank letters of credit of $69 million (2002 - $97 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2003 and in total thereafter are as follows: 2004 - $9 million; 2005 - $5 million; 2006 - $4 million; 2007 - $3 million; 2008 - $2 million; and thereafter - $3 million.

19. SEGMENT REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The “other” segment, which primarily consists of telecommunications. In 2002 this segment also included energy services. Substantially all of the assets pertaining to the energy retail operations of the energy services business were sold (see Note 13).

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2003				
Segment profit				
Revenues	1,298	2,734	26	4,058
Purchased power	-	1,872	-	1,872
Operation, maintenance and administration	382	387	26	795
Depreciation and amortization	228	223	3	454
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	688	252	(3)	937
Financing charges				348
Income before provision for payments in lieu of corporate income taxes				589
Capital expenditures	289	292	16	597
2002				
Segment profit				
Revenues	1,317	2,682	32	4,031
Purchased power	-	1,857	1	1,858
Operation, maintenance and administration	374	383	75	832
Depreciation and amortization	213	190	8	411
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	730	252	(52)	930
Financing charges				353
Income before provision for payments in lieu of corporate income taxes				577
Capital expenditures	260	286	24	570

December 31 (Canadian dollars in millions)	**2003**	**2002**
Total assets		
Transmission	6,589	6,638
Distribution	4,623	4,694
Other	94	90
	11,306	11,422

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

20. COMPARATIVE FIGURES

The *Electricity Pricing, Conservation and Supply Act*, 2002 stipulated a fixed energy price of 4.3 cents per kWh for low volume and designated customers, retroactive to Open Access, May 1, 2002. The Company has retroactively restated its revenue and purchased power for the period May 1, 2002 to December 31, 2002 to reflect the 4.3 cents per kWh price. These offsetting restatements have not resulted in any adjustment to the net income previously reported. The Company's December 31, 2002 balance sheet has also been restated to adjust accounts payable and accrued charges to reflect the 4.3 cents kWh price.

The comparative Consolidated Financial Statements have also been reclassified from statements previously presented to conform to the presentation of the December 31, 2003 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR[1] SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**	**2001**	**2000**	**1999**
Statement of operations data					
Revenues					
Transmission	1,298	1,317	1,259	1,260	1,237
Distribution	2,734	2,682	2,158	1,703	1,793
Other	26	32	49	32	95
	4,058	4,031	3,466	2,995	3,125
Costs					
Purchased power	1,872	1,858	1,267	859	939
Operation, maintenance and administration[2]	795	832	824	863	863
Depreciation and amortization	454	411	384	348	342
Transitional cost adjustment[3]	-	-	-	-	55
Provincial debt guarantee fee[4]	-	-	-	-	8
	3,121	3,101	2,475	2,070	2,207
Other income					
Gain on sale of investment[5]	-	-	-	-	32
Income before financing charges and provision for payments in lieu of corporate income taxes	937	930	991	925	950
Financing charges	348	353	350	340	381
Income before provision for payments in lieu of corporate income taxes	589	577	641	585	569
Provision for payments in lieu of corporate income taxes	193	233	267	207	194
Net income	396	344	374	378	375
Basic and fully diluted earnings per common share[6] *(Canadian dollars)*	3,779	3,258	3,562	3,182	-

[1] The results of operations and financial positions prior to April 1, 1999 may have been different if Hydro One had been a stand-alone corporation with its own management and capital structure, rather than a business unit of Ontario Hydro.

[2] Operation, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program and for 1999 included a net charge of $24 million for a staff reduction program and the reversal of certain provisions.

[3] The transitional cost adjustment was a one-time charge that represented the difference between allowed costs specified in the OEB rate orders and costs incurred by Ontario Hydro during the first three months in 1999 that were allowed under the *Power Corporation Act.*

[4] The provincial debt guarantee fee was an annual fee equal to one-half of one per cent (0.5%) of the total debt guaranteed by the Province outstanding as of the preceding December 31. This fee was eliminated effective April 1, 1999.

[5] On September 15, 1999, Hydro One sold its 25% equity in Ontario Quinta A.V.V., resulting in a gain on sale.

[6] On March 31, 2000, Hydro One issued to the Province 12,920,000 5.5% cumulative preferred shares and 99,990 common shares.

HYDRO ONE INC.
FIVE-YEAR[1] SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	**2003**	**2002**	**2001**	**2000**	**1999**
Financial position data					
Assets:					
Transmission	6,589	6,638	6,693	6,477	6,643
Distribution	4,623	4,694	4,416	3,434	3,377
Other	94	90	122	86	70
Total assets	11,306	11,422	11,231	9,997	10,090
Other financial data					
EBITDA[7]	1,391	1,341	1,375	1,273	1,292
Capital expenditures:					
Transmission	289	260	274	280	327
Distribution[8]	292	286	247	152	186
Other	16	24	45	14	16
Total capital expenditures	597	570	566	446	529
Ratios					
Net asset coverage on long-term debt[9]	1.86	1.90	1.88	1.90	1.83
Earnings coverage ratio[10]	2.43	2.35	2.53	2.37	2.19
Operating statistics					
Transmission:					
Units transmitted (TWh)[11]	151.7	153.2	146.9	146.9	144.1
System peak demand (MW)[11]	24,849	25,629	25,269	23,428	23,435
Total transmission lines (circuit-kilometres)	28,621	28,492	28,387	28,490	28,889
Distribution:					
Units distributed (TWh)[11]	27.9	27.1	21.3	17.6	18.1
Total distribution lines (circuit-kilometres)	123,297	122,830	122,399	113,880	113,400
Customers	1,238,748	1,219,614	1,193,089	957,474	933,990
Total regular employees[12]	3,967	3,933	4,815	4,468	5,632

[7] EBITDA represents income before financing charges, provision for payments in lieu of corporate income taxes, depreciation and amortization and does not include financing income. This non-GAAP measure is provided because it is a standard and useful measure of the Company's financial performance.

[8] Capital expenditures exclude $468 million in 2001 and $23 million in 2000 associated with acquisitions of local distribution companies.

[9] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[10] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[11] System related statistics include preliminary figures for December.

[12] On March 1, 2002, approximately 770 regular employees were transferred to Inergi LP (see Note 18).