

**HYDRO ONE INC.**  
**MANAGEMENT'S DISCUSSION AND ANALYSIS OF**  
**FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

*You should read the following discussion in conjunction with our Consolidated Financial Statements for the three-year period ended December 31, 2001. 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, (Canadian GAAP), which differs in some respects from accounting principles generally accepted in the United States (U.S. GAAP). See Note 25 to the Consolidated Financial Statements for the three-year period ended December 31, 2001. The following discussion is based upon our Consolidated Financial Statements prepared in accordance with Canadian GAAP, except as otherwise indicated.

## **Overview**

### **Our Businesses**

We own and operate the second largest transmission system in North America and the largest distribution system in Ontario, based on assets as at December 31, 2001. Our company was formed as part of the reorganization of Ontario Hydro and acquired the transmission, distribution and energy services businesses of Ontario Hydro as of April 1, 1999.

In 2001, our transmission business generated approximately 36% of our total revenues and approximately 69% of our profit before financing charges and provision for payments in lieu of corporate income taxes, while our distribution business accounted for approximately 62% of our total revenues and approximately 34% of our profit before financing charges and provision for payments in lieu of corporate income taxes. The contribution to revenues of our distribution business is significantly higher than the contribution to the revenues of our transmission business because the cost of power is included in the revenues of our distribution business.

Our businesses are in three segments: transmission; distribution; and other businesses.

Our transmission business, which represented approximately \$6.7 billion of our assets as at December 31, 2001, transmits electricity through an approximately 28,400 circuit-kilometre high-voltage transmission network. We transmit electricity from generators to local distribution companies, including our own distribution network, and industrial customers with a direct connection to our transmission system. We own and operate this high-voltage transmission system as well as 26 facilities that inter-connect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately \$4.4 billion of our assets as at December 31, 2001, distributes electricity through our approximately 122,000 circuit-kilometre low-voltage distribution system to approximately 1.2 million rural and urban customers, and local distribution companies that are not directly connected to our high-voltage transmission system. Our distribution service territory includes all of Ontario, excluding the service territories of the 97 local distribution companies that we do not own. Since April 1999, we have acquired 88 local distribution companies that we now operate as part of our distribution business. We also operate generation and distribution systems in 19 remote communities across northern Ontario that are not connected to Ontario's electricity grid.

Our other businesses, which represented approximately \$122 million of our assets as at December 31, 2001, involve the marketing of our fibre-optic capacity to telecommunications carriers and commercial customers, and the retail sale of energy and related services.

Since the date of incorporation, all of the outstanding shares of our company have been owned by the Province of Ontario (the Province). On March 28, 2002, we filed a preliminary prospectus in Canada and a registration statement on Form F-1 in the United States in contemplation of the sale of our outstanding common shares by the Province (the Offering).

On April 19, 2002, the Ontario Superior Court ruled that the *Electricity Act, 1998* restricted the Province's right to sell the common shares of Hydro One that it owns. On April 25, 2002, the Province announced that it will appeal the court ruling and that it intends to develop proposed legislation in respect of the privatization of Hydro One.

## **Revenues and Costs**

We earn transmission revenues based on the peak demand for electricity capacity across our high-voltage network, and we earn distribution revenues by delivering power to our distribution customers. The rates that we charge are established under rate orders issued by the Ontario Energy Board for these regulated businesses. Distribution revenues have been based on a "bundled" customer charge for the cost of power, transmission and distribution of electricity as well as related services to customers in our service territory.

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. In addition, these costs include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Purchased power costs incurred in our distribution business primarily represent the costs of electricity delivered to customers within our distribution service area.

Financing charges primarily consist of interest expense associated with our debt.

Since April 1, 1999, we have been making payments in lieu of corporate income taxes to Ontario Electricity Financial Corporation in accordance with the *Electricity Act, 1998* on the same basis as if we were subject to federal and provincial corporate taxes. We provide for payments in lieu of corporate income taxes relating to our regulated businesses using the taxes payable method as directed by the Ontario Energy Board. As a result of the Offering, we will instead pay corporate income taxes to federal and provincial tax authorities.

## **Regulation of Our Businesses**

Our industry has undergone a significant restructuring initiated by the Province. Under the *Electricity Act, 1998*, as of April 1, 1999, the businesses of Ontario Hydro were reorganized into five separate corporations, including our company as the successor corporation to Ontario Hydro's electricity transmission, distribution and energy services businesses. We expect the restructuring to result in Ontario's wholesale and retail electricity markets becoming open to competition, commonly referred to as Open Access, on May 1, 2002.

During the transition to Open Access, electricity consumers pay bundled rates, consisting of an aggregate charge for the generation, transmission and distribution of electricity that they use as well as other related charges. The aggregate amount of these bundled rates is allocated among generators, transmitters and distributors. The amounts owing to the five successor corporations to Ontario Hydro are allocated under the terms of a revenue allocation agreement entered into by them. Upon Open Access, electricity consumers will pay unbundled rates for the generation, transmission and distribution of the electricity used by them and other related charges.

Prior to Open Access, revenues are allocated to our transmission and distribution businesses under rate orders based on a revenue requirement that provides for an annual rate of return of 9.88% on the common equity deemed to be allocated to our transmission and distribution businesses. The rate orders are premised upon a deemed capital structure of 60% debt, 4% preferred equity and 36% common equity for each of our regulated businesses. Any divergence in our actual capital structure affects the actual rate of return on the average common equity and the overall financial performance of these regulated businesses. The rate orders do not prescribe a capital structure for our company on a consolidated basis or for any of our non-regulated businesses. Currently, each of our regulated businesses has an actual capital structure which corresponds to the Ontario Energy Board deemed capital structure. In addition, the Ontario Energy Board could modify the annual rate of return and the deemed capital structure for our regulated businesses in the future, which could affect the financial performance of these regulated businesses and our company as a whole. If actual costs exceed allowed costs for any reason, the rate of return on our common equity and our resulting net income are likely to be adversely affected.

Upon Open Access, the Independent Electricity Market Operator will remit payments to us based on transmission rates approved by the Ontario Energy Board. The Ontario Energy Board has approved, on an interim basis, uniform transmission rates that will apply to all transmitters across Ontario following the commencement of Open Access. Our approved revenue requirement will remain unchanged as a result of these uniform rates and is designed to yield an approved rate of return of 9.88% on our deemed common equity. We are currently in the process of developing a performance based regulation rate proposal for our transmission business. The first step in such process will be consultation in 2002 with stakeholders, including customers, generators and other interested persons, on our proposal for a performance based regulatory framework for our transmission business.

In our distribution business, during 2001 the wholesale cost of power to us was increased on two occasions. Effective June 1, 2001, the Province passed a regulation that increased to all distribution companies, including ours, the wholesale cost of power supplied by Ontario Power Generation Inc. by 0.7 cents per kWh. The Ontario Energy Board approved the incorporation of this non-distribution-related increase into customers' bundled rates. The wholesale cost of power to our distribution business was further increased by 1.15 cents per kWh effective October 1, 2001 so that after such increase our cost of power was consistent with the rate paid by other large distributors. Following discussions with our shareholder, which requested us to mitigate the transition to these higher costs of electricity for our customers, we applied for lower distribution revenues than we had originally requested, with this mitigation to be partially phased out over a three-year period. The Ontario Energy Board issued an interim approval of the first phased increase, effective October 1, 2001; and the second phased increase, effective March 1, 2002. We have requested that the third phased increase be effective March 31, 2003. The Ontario Energy Board is expected to make a final determination with respect to the approval of these increases in mid-2002. As a result of the phasing-in of the partial recovery of the shortfall in our distribution revenues, we will not achieve our approved rate of return of 9.88% on deemed common equity of our distribution business in 2002 and 2003. In 2002, we will start the process to submit to the Ontario Energy Board a rate proposal based on a second generation performance based regulatory framework for our distribution business along with a proposal for our transmission business. We expect the Ontario Energy Board approved rates for 2004 to provide for a full market based rate of return.

We have also received interim approval of unbundled rates for the local distribution companies we acquired. We have separately filed rate applications for 2002 for these utilities with the Ontario Energy Board.

Upon Open Access, in addition to transmission and distribution revenues, we will receive revenues from end use consumers derived from our standard supply obligation and our competitive retail business. Our standard supply obligation refers to our obligation following the commencement of Open Access to sell electricity to every customer connected to our distribution system who has not selected an alternate electricity supplier. The Ontario Energy Board will regulate rates for our standard supply customers, but not for customers of our competitive retail business.

A condition of our distribution licence, as for all distributors, is fulfilment of preparations for Open Access, which is referred to as being "Market Ready". We have developed the systems, processes and communications required for Open Access and have participated in the successful market design tests sponsored by the Independent Electricity Market Operator. As a result, we believe that we are well-positioned to participate in the new marketplace and to meet our Market Ready obligations, while continuing to deliver electricity safely and reliably.

The restructuring of Ontario's electricity industry and the development of the regulatory framework will continue beyond the commencement of Open Access. Over the long-term, we believe that performance based regulation should benefit us and our customers by providing our company with an opportunity to enhance earnings while delivering rates to customers that reflect continuing efficiency improvements and maintain our current high levels of service.

## **Results of Operations**

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, in any year are made by comparison to the corresponding prior year.

## Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

### *Revenues*

**Transmission.** Transmission revenues declined by \$1 million to \$1,259 million in 2001. Tariff revenues increased by \$31 million, or 3%, in 2001 as a result of transmission load growth in accordance with the revenue allocation agreement. This increase was offset by a decline in non-energy related service revenues of \$32 million as a result of substantial one-time revenues recorded in 2000 relating to contract work preparing other industry participants for Open Access.

**Distribution.** Distribution revenues increased by \$455 million, or 27%, to \$2,158 million in 2001. Revenues from the sale and delivery of electricity increased by \$344 million, of which \$268 million was attributable to the acquisitions of local distribution companies. In addition, revenues were higher as a result of the two rate increases related to the wholesale cost of power. The June 1, 2001 rate increase accounted for a \$93 million rise in distribution revenues and the October 1, 2001 rate increase accounted for an additional \$18 million.

**Other.** Other revenues increased by \$17 million, or 53%, to \$49 million in 2001. Energy services revenues increased by \$10 million primarily due to increased sales of ancillary residential services. Revenues from our telecommunications business increased by \$7 million, primarily from sales of dark fibre capacity to major carriers.

### *Operation, Maintenance and Administration Costs*

Total operation, maintenance and administration costs declined by \$39 million, or 5%, to \$824 million in 2001, due to the factors discussed below.

**Transmission.** Transmission operation, maintenance and administration costs declined by \$79 million, or 18%, to \$354 million in 2001. Expenditures necessary to sustain our transmission system, including preventive and corrective maintenance on transformer stations, transmission lines and telecommunications equipment, declined by \$17 million. In addition to achieving a full year of savings in 2001 as a result of the substantial completion of a staff reduction program in 2000, we embarked on a number of initiatives to enhance productivity, such as improving labour utilization. See "— Year Ended December 31, 2000 Compared to Year Ended December 31, 1999 — Staff Reduction Program and Other Provisions". Key initiatives to improve labour utilization include a hiring hall established with the Power Workers' Union to provide staffing flexibility and the use of temporary headquarters to reduce travelling time for our line and forestry crews. Expenditures to operate and support our transmission system declined by \$24 million, primarily as a result of the staff reduction program. In addition, costs incurred to provide non-energy-related services declined by \$38 million due to the substantial completion of work in 2000 for other industry participants in preparation for Open Access.

**Distribution.** Distribution operation, maintenance and administration costs increased by \$3 million, or 1%, to \$391 million in 2001. Costs incurred to sustain our distribution system, including our remote system, which are related primarily to customer trouble calls to restore power, vegetation management and line and station maintenance work, increased by \$38 million. We also incurred an additional \$13 million in one-time operation, maintenance and administration costs to integrate acquired local distribution companies. We achieved a reduction of \$48 million in costs to operate and support our distribution system primarily from the staff reduction program as well as productivity initiatives similar to those of our transmission business.

**Other.** Other operation, maintenance and administration costs increased by \$37 million to \$79 million in 2001. This increase was primarily associated with the growth of our telecommunications and energy services businesses.

### *Purchased Power*

Purchased power costs increased by \$408 million, or 48%, to \$1,267 million in 2001. The increase attributable to acquisitions and volume growth totalled \$265 million, including \$211 million attributable to acquisitions of local distribution companies. In addition, as discussed above under "— Regulation of our Business", the Province passed regulations effecting two increases in the wholesale cost of power during 2001. The June 1, 2001 and October 1, 2001 increases and a change in the pricing methodology of Ontario Power Generation Inc. resulted in higher purchased power costs totalling \$143 million.

### ***Depreciation and Amortization***

Depreciation and amortization expense increased by \$36 million, or 10%, to \$384 million in 2001. Depreciation expense increased by \$30 million primarily due to the acquisitions of local distribution companies as well as to our expanded capital expenditure program. Amortization expense increased by \$6 million, of which \$5 million was due to the amortization of the regulatory asset recorded effective January 1, 2001 for the recovery of costs required to remediate past environmental contamination and \$1 million was due to the amortization of goodwill related to the acquisitions of local distribution companies.

### ***Financing Charges***

Financing charges increased by \$10 million, or 3%, to \$350 million in 2001. This increase principally reflects higher average levels of debt.

### ***Provision for Payments in Lieu of Corporate Income Taxes***

The provision for payments in lieu of corporate income taxes increased by \$60 million, or 29%, to \$267 million in 2001. This increase reflects higher levels of income and lower available tax deductions, partially offset by a reduction in the statutory tax rate from 43.95% in 2000 to 41.74% in 2001. Lower tax deductions were primarily attributable to the absence in 2001 of tax deductions available in 2000 related to the staff reduction program and capital cost allowance deductions. Tax deductions related to the staff reduction program were primarily taken in 2000 when the related cash payments were made. As a result of the Offering, we will commence paying corporate income taxes to Canadian federal and provincial tax authorities.

### ***Net Income***

As a result of the above factors, net income declined by \$4 million to \$374 million in 2001. Net income after dividends on our preferred shares was \$356 million in 2001, compared to \$360 million in 2000 after adjusting for \$13 million of 2000 preferred dividends paid in respect of 1999.

Excluding the impact of staff reductions, net income increased from \$350 million in 2000 to \$374 million in 2001. Excluding the impact of staff reductions, net income after dividends on our preferred shares increased from \$332 million in 2000, after adjusting for \$13 million of 2000 preferred dividends paid in respect of 1999, to \$356 million in 2001.

Net income in 2001 for our regulated transmission and distribution businesses on a combined basis was in line with the annual regulated rate of return of 9.88% in 2001 provided for in our transitional rate orders.

### **Year Ended December 31, 2000 Compared to Year Ended December 31, 1999**

Prior to 1999, transmission revenues were determined primarily based on an estimate of planned costs and a specified rate of return on assets. Distribution revenues were comprised of amounts received for the sale and delivery of electricity to customers and the rural rate assistance program, which is discussed below. Effective April 1, 1999, the Ontario Energy Board issued, and the Minister of Energy, Science and Technology approved, transitional rate orders that provide the transmission and distribution revenue requirements for 1999 and 2000.

Our company received revenues for the three months ended March 31, 1999 on the basis of the allowed costs under the transitional rate orders. Because we did not actually begin to incur these allowed costs until April 1, 1999, our costs for the first quarter of 1999 did not reflect the basis of our revenue requirement under the transitional rate orders. As a result, we recorded a transitional cost adjustment of \$55 million, calculated as the difference between the costs allowed under the *Power Corporation Act*, which governed Ontario Hydro, and those allowed under the transitional rate orders to correct this mismatch. This adjustment will not recur because, after April 1, 1999, the costs incurred by our company are the higher costs assumed under these rate orders so that there will no longer be a mismatch between revenues and costs.

Additional allowed costs under the transitional rate orders consisted of payments in lieu of corporate taxes, as well as an amount for amortization relating to the recovery of other post-employment benefit costs. These additional costs were partially offset by reduced financing charges resulting from lower debt balances that reflected the new capital structure of our company and lower interest rates as well as the elimination of a debt guarantee fee levied by the Province.

The following discussion of our results of operations for 1999 is based on combined results for our twelve months ended December 31, 1999, which includes the three months ended March 31, 1999, the period prior to our acquisition of Ontario Hydro's transmission, distribution and energy services businesses. Our results of operations for this three month period reflect the specific identification of assets, liabilities, revenues and expenses relating to the businesses acquired by us as well as a notional allocation of specified financial statement accounts and items of Ontario Hydro to us and the other successor corporations of Ontario Hydro. See Note 2 to the Consolidated Financial Statements for the three-year period ended December 31, 2001.

### ***Revenues***

***Transmission.*** Transmission revenues increased by \$23 million, or 2%, to \$1,260 million in 2000. Of this increase, \$19 million was a result of the increase in the allowed rate of return to 9.88% in 2000 from 9.35% in 1999. The remaining increase in revenues was attributable to the increase in non-energy-related services provided to other industry participants in preparation for Open Access.

***Distribution.*** Distribution revenues declined by \$90 million, or 5%, to \$1,703 million in 2000. Approximately \$44 million of this decline was attributable to a reduction in allowed costs provided for under the distribution transitional rate order for 2000. In addition, revenues from the sale and delivery of electricity declined by \$46 million, which includes a \$41 million reduction related to a lower demand for electricity and a \$16 million reduction related to the annexation of part of our service territory by a number of local distribution companies prior to April 1, 1999, partially offset by an \$11 million reduction in line losses. The ability of municipalities to annex areas previously served by us ceased as of April 1, 1999.

***Other.*** Other revenues declined by \$63 million, or 66%, to \$32 million in 2000. Other revenues for periods prior to 2000 were substantially derived from the activities of Ontario Hydro International Inc., a subsidiary that was wound-up effective as at January 1, 2002. As part of the process to wind-up its operations, the main operating asset, an investment in Ontario Quinta A.V.V., was sold on September 15, 1999. The reduction in revenues from Ontario Hydro International Inc. accounted for a reduction in other revenues of \$72 million in 2000. Excluding the impact from Ontario Hydro International Inc., other revenues increased by \$9 million in 2000 as a result of the launch of our telecommunications business and new energy services.

### ***Operation, Maintenance and Administration Costs***

Total operation, maintenance and administration costs amounted to \$863 million in both 2000 and 1999.

***Transmission.*** Transmission operation, maintenance and administration costs increased by \$10 million, or 2%, to \$433 million in 2000. Costs incurred to sustain our transmission system increased by \$10 million. Higher costs for telecommunications and line work were partially offset by lower planning and engineering costs. Costs incurred to provide non-energy-related services increased by \$4 million, consistent with the increase in the level of services provided. These increases were partially offset by a reduction of \$4 million in centralized support costs, which was primarily attributable to the staff reduction program.

***Distribution.*** Distribution operation, maintenance and administration costs increased by \$6 million, or 2%, to \$388 million in 2000. This increase primarily reflected incremental costs of \$10 million incurred to integrate and support the acquisitions of local distribution companies. Costs incurred to sustain our distribution system were consistent with 1999. Lower costs for line maintenance and vegetation management were offset by higher costs to operate our remote system, primarily due to higher fuel prices. Operation, maintenance and administration costs incurred to operate and support the distribution system were also consistent with 1999 levels. Higher property taxes and payments in lieu of corporate taxes, as well as higher customer service operating costs were substantially offset by a reduction in centralized support costs. The reduction in centralized support costs was primarily related to the staff reduction program. These overall increases in distribution operation, maintenance and administration costs were partially offset by a reduction of \$5 million in costs associated with non-energy-related services resulting from a change in the service mix.

**Other.** Other operation, maintenance and administration costs declined by \$16 million, or 28%, to \$42 million in 2000. The \$31 million decrease attributable to Ontario Hydro International Inc. was partially offset by an increase of \$15 million related to the establishment of the telecommunications and energy services businesses.

#### ***Staff Reduction Program and Other Provisions***

In November 1999, we implemented a staff reduction program as part of our ongoing cost reduction program. We recorded a provision in 1999 in the amount of \$60 million for this program. With approximately 1,400 employees accepting early retirement, the staff reduction program was substantially completed during 2000. Costs of \$53 million were charged to the provision in 2000 and \$2 million was charged in 2001. In 2000, \$5 million of the provision was determined to be unnecessary and, accordingly, was reversed as a credit to the results of operations. In 1999, we also re-evaluated the need for some provisions previously recognized by Ontario Hydro and assumed by our company as of April 1, 1999. As a result, remaining provisions of \$36 million associated with an involuntary staff reduction program and surplus real estate were reversed as a credit to the results of operations in 1999.

#### ***Purchased Power***

Purchased power costs declined by \$80 million, or 9%, to \$859 million in 2000. Approximately \$43 million of the reduction was due to the lower demand for electricity and the annexations by local distribution companies of areas that we previously served. The decline associated with the sale of our investment in Ontario Quinta A.V.V. amounted to \$37 million.

#### ***Depreciation and Amortization***

Depreciation and amortization expense increased by \$6 million, or 2%, to \$348 million in 2000. The increase in depreciation expense from our expanded capital expenditure program amounted to \$16 million. This increase was partially offset by lower amortization expense of \$10 million. A reduction of \$20 million in amortization expense from a fully amortized regulatory asset in 1999 was partially offset by a \$10 million increase in amortization of the regulatory asset associated with employee future benefit costs other than pension.

#### ***Transitional Cost Adjustment***

We had a one-time transitional cost adjustment of \$55 million in 1999 with respect to the three months ended March 31, 1999. This charge represented the difference between allowed costs specified in the transitional rate orders approved by the Ontario Energy Board and costs that were allowed under the *Power Corporation Act*.

#### ***Provincial Debt Guarantee Fee***

The Province no longer guarantees our debt and, consequently, we did not incur a debt guarantee fee for any period subsequent to April 1, 1999. Prior to April 1, 1999, the Province guaranteed the debt of Ontario Hydro, for which Ontario Hydro paid an annual fee equal to one-half of one percent of the principal amount of such guaranteed debt.

#### ***Gain on Sale of Investment***

On September 15, 1999, our subsidiary, Ontario Hydro International Inc., sold its 25% equity interest in Ontario Quinta A.V.V. We realized a gain of \$32 million before payments in lieu of corporate income taxes on this sale in 1999.

#### ***Financing Charges***

Financing charges declined by \$41 million, or 11%, to \$340 million in 2000. The decrease in 2000 was primarily due to a reduction in long-term debt servicing costs, with \$28 million from lower average levels of debt and \$10 million from lower average interest rates.



## ***Capital Expenditures***

Our total capital expenditures amounted to \$566 million in 2001, representing an increase of \$120 million over spending levels of \$446 million in 2000. Capital expenditures in 2000 were \$83 million lower than 1999 levels of \$529 million. These amounts exclude capital expenditures associated with acquisitions of local distribution companies.

***Transmission.*** Capital expenditures for our transmission business were \$274 million, \$280 million and \$327 million in 2001, 2000, and 1999, respectively. Capital expenditures on transmission stations, lines, equipment and telecommunications refurbishment were \$184 million, \$183 million and \$193 million in 2001, 2000 and 1999, respectively. Increased spending on telecommunications facilities for transmission was partially offset by lower pole replacement work in 2001 compared to 2000. Lower pole replacement work and lower investments in transportation and work equipment were partially offset by increased load connection replacements and network refurbishment projects in 2000 compared to 1999. Capital expenditures incurred to expand our transmission system were \$60 million and \$64 million in 2001 and 2000, respectively, and were significantly lower than expenditures of \$101 million in 1999. Capital expenditures in 1999 were higher than in 2001 and 2000 primarily as a result of the substantial completion of a number of construction and development projects in 1999. Capital expenditures supporting transmission operations declined marginally in 2001 to \$30 million, compared to \$33 million in each of 2000 and 1999.

***Distribution.*** Capital expenditures for our distribution business, excluding expenditures associated with acquisitions of local distribution companies, were \$247 million in 2001, compared with \$152 million and \$186 million in 2000 and 1999, respectively. Customer-demand-driven capital expenditures increased to \$103 million in 2001, compared with \$79 million in 2000 and \$78 million in 1999. The expansion of our service territory through local distribution company acquisitions was a principal reason for this increase. Capital expenditures incurred to sustain our distribution asset base amounted to \$94 million in 2001, compared with \$34 million and \$78 million in 2000 and 1999, respectively. In 2001, we enhanced our wood pole replacement program in response to an asset condition study. We also increased our spending levels on lines and stations in 2001, primarily in response to our expanded service territory and to higher storm damage. Capital expenditures supporting distribution operations increased to \$50 million from \$39 million in 2000 and \$30 million in 1999. Projects for 2001 and 2000 have been focused on preparation of our systems and processes for Open Access.

***Other.*** Capital expenditures for our other businesses amounted to \$45 million in 2001 compared with \$14 million in 2000, and \$16 million in 1999. Increased expenditures in 2001 were made primarily in support of our emerging telecommunications business. In addition to lighting dark fibre in the Windsor, Fort Erie and Ottawa corridor, we began construction of a fibre-optic network between Buffalo, Ottawa and Montreal.

***Future Capital Expenditures.*** Capital expenditures are budgeted at approximately \$590 million in 2002. The budgets for our transmission and distribution businesses are \$290 million and \$260 million, respectively. Other capital expenditures are budgeted at \$40 million and are primarily related to the expansion of our fibre-optic communication system between Buffalo, Ottawa and Montreal in support of our growing telecommunications business.

In addition to the ongoing sustainment requirements of the transmission and distribution systems, the 2002 budget includes a number of major projects. We plan to begin construction of an integrated operating centre to replace our eight territory operating centres in 2002 and complete the facility in 2004. Other projects include information technology enabling tools for our corporate functions and services staff and development opportunities such as an interconnection project with Hydro-Québec.

We have agreed to enter into a partnership with TransÉnergieUS, a subsidiary of Hydro-Québec, to build a high-voltage transmission line beneath Lake Erie, linking Ontario and Ohio or Pennsylvania, or both. On February 13, 2002, we and TransÉnergieUS received approval from the U.S. Federal Energy Regulatory Commission to proceed with a sale of the transmission rights for this line at negotiated rates by using an open season process to attract customers. Our share of the capital costs related to this project cannot currently be determined and would, in part, depend on the outcome of the sale of the transmission rights, but could be substantial in amount.

### ***Servicing and Repayment of Our Debt***

As at December 31, 2001, we had long-term debt outstanding of \$4,522 million, including the current portion, with a weighted-average interest rate of 8.0%. Of this amount, \$2,972 million is payable to Ontario Electricity Financial Corporation and \$1,550 million is publicly held. Outstanding short-term promissory notes amounted to \$410 million with a weighted-average interest rate of 2.16%.

The notes payable to Ontario Electricity Financial Corporation mature between 2002 and 2007, including approximately \$443 million in 2002 and \$651 million in 2003. We plan to refinance Ontario Electricity Financial Corporation debt maturing during 2002 and 2003 principally through our medium term note program. Our publicly held notes and debentures mature between 2005 and 2032.

### ***Outsourcing Arrangement***

We recently entered into an outsourcing services agreement with Inergi LP, an affiliate of Cap Gemini Ernst & Young Canada Inc. Under this agreement, Inergi LP will provide us with, among other things, customer service operations, supply management, pay operations, information technology, and finance and accounting services over a 10-year term. As part of this outsourcing arrangement, approximately 900 of our employees were transferred to Inergi LP. The initial fee payable to Inergi LP will be approximately \$130 million in the first year of the contract declining to approximately \$90 million in the tenth year of the agreement, net of inflation adjustments and subject to decreases based on external benchmarking analysis every three years. Because this outsourcing arrangement provides for a defined competitive and continuously improved price for the outsourced services, we believe that it will allow us to continue to reduce our cost base and improve our competitive position. As part of this agreement, we are still responsible for the capital expenditures associated with these services.

### ***Acquisitions and Other Investing Activities***

Cash used for investing activities increased by \$475 million, or 88%, to \$1,013 million in 2001 and by \$297 million, or 123%, to \$538 million in 2000, compared to the prior years. The increase in 2001 reflected our local distribution company acquisition program, through which we acquired 88 local distribution companies since April 1999. In 2001, we acquired 71 local distribution companies at a total cost of \$475 million. In 2000, we acquired 16 local distribution companies at a total cost of \$23 million and made deposits of \$57 million with respect to acquisitions completed in 2001. Cash used for investing activities in 1999 also reflects the receipt of proceeds of \$245 million from the sale of fixed assets and investments, primarily related to Ontario Quinta A.V.V.

We may pursue acquisitions of additional local distribution companies in 2002 or future years, although no specific material transactions are currently pending or under consideration. We also anticipate that, consistent with our long-term strategy, we will pursue, either alone or with partners, acquisitions of transmission and distribution businesses and assets in nearby market areas in North America. We believe that we will have access to sufficient sources of liquidity and capital resources, including through debt financing and/or issuances of new common shares by our company.

### ***Dividends***

We paid dividends to the Province on our outstanding preferred shares and common shares totalling \$258 million in 2001 and \$398 million in 2000. Dividends paid were substantially lower in 2001 because dividends of \$171 million pertaining to 1999 were paid in 2000 in conjunction with the issuance of shares to the Province on March 31, 2000.

Our outstanding preferred shares are entitled to a total annual cumulative dividend of \$18 million, payable on a quarterly basis.

The dividends on our common shares are declared at the discretion of our board of directors, and will be recommended by our management based on our results of operations, financial condition, cash requirements and other relevant factors, such as industry practice. In 2001, dividends on our common shares in the amount of \$240 million were declared as compared with \$371 million in 2000. Of these dividends declared during 2000, \$158 million were declared in respect of the nine months ended December 31, 1999.

## ***Recapitalization and Other Matters Relating to the Offering***

Immediately prior to the completion of the Offering, the Province will subscribe for \$290 million of our common shares at the initial public offering price, the proceeds of which will be used to fund our ongoing obligations. These additional common shares will also be offered for sale by the Province as part of the Offering. In connection with the Offering, we will redeem our outstanding preferred shares held by the Province for an aggregate redemption amount of \$323 million, together with accrued dividends, within 120 days of the closing of the Offering. We plan to finance this redemption through an offering of a new series of preferred shares. Prior to that offering, we may finance this redemption through borrowings under our credit facility or other resources. As a result of the Offering, we will also be required to make a payment in lieu of corporate taxes of \$440 million to Ontario Electricity Financial Corporation. We will not receive any proceeds from the Offering.

### **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.

	<u>Total</u>	<u>2002</u>	<u>Due by Year</u>		<u>After 2006</u>
			<u>2003/2004</u>	<u>2005/2006</u>	
			(Canadian dollars in millions)		
<b>Contractual obligations:</b>					
Short-term notes payable .....	410	410	—	—	—
Long-term debt .....	4,522	443	1,333	1,096	1,650
Operating lease commitments.....	66	19	28	13	6
Energy purchase contracts (electricity and gas).....	75	14	32	27	2
Inergi LP outsourcing agreement.....	<u>1,050</u>	<u>108</u>	<u>230</u>	<u>212</u>	<u>500</u>
Total contractual obligations .....	<u>6,123</u>	<u>994</u>	<u>1,623</u>	<u>1,348</u>	<u>2,158</u>

	<u>Total</u>	<u>2002</u>	<u>Expiration Date by Year</u>		<u>After 2006</u>
			<u>2003/2004</u>	<u>2005/2006</u>	
			(Canadian dollars in millions)		
<b>Other commercial commitments:</b>					
Letters of credit <sup>(1)</sup> .....	158	108	50	—	—
Guarantees <sup>(2)</sup> .....	<u>80</u>	<u>—</u>	<u>—</u>	<u>80</u>	<u>—</u>
Total other commercial commitments .....	<u>238</u>	<u>108</u>	<u>50</u>	<u>80</u>	<u>—</u>

(1) We currently have bank letters of credit of \$108 million outstanding relating to retirement compensation agreements. In addition, upon Open Access, we will be required to provide prudential support to the Independent Electricity Market Operator, which requirement we intend to satisfy using a combination of bank letters of credit of \$50 million and guarantees by Hydro One Inc. of our subsidiaries' obligations.

(2) Limited guarantees have been provided to counterparties of our subsidiary, Ontario Hydro Energy Inc.

Payments in respect of operating leases, energy purchase contracts (electricity and gas) and our new outsourcing agreement with Inergi LP 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 statement 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.

The above table does not include amounts payable as a result of the Offering as described under "— Recapitalization and Other Matters Relating to the Offering".

### **Sources of Liquidity and Capital Resources**

Our primary sources of liquidity and capital resources are the following:

- funds generated from operations;
- debt capital markets borrowings; and
- bank financing.

Funds from operations, after the payment of dividends, will not be sufficient to fund our repayment of existing indebtedness and to meet our anticipated liquidity, maintenance and other capital resource requirements. As a result, we expect to incur significant amounts of debt. We do not expect that the covenants limiting the incurrence of indebtedness contained in our existing debt agreements will prevent us from incurring sufficient new indebtedness to meet our requirements for the foreseeable future.

### ***Funds Generated from Operations***

Net cash generated from operations was \$914 million in 2001, compared with \$725 million in 2000 and \$840 million in 1999. The increase of \$189 million in 2001 reflects significantly higher accounts payable and accrued charges, primarily from increases in the cost and volume of wholesale power, the operations of the acquired local distribution companies and higher provision for payments in lieu of corporate income taxes. The increase in accounts payable and accrued charges was partially offset by higher levels of accounts receivable from our electricity customers due to the increase in our customer base and the rate increases attributable to the wholesale cost of power.

The reduction in net cash generated from operations of \$115 million in 2000 was due primarily to higher levels of working capital. Accounts payable and accrued liabilities declined due to cash payments made under the staff reduction program and the resulting reduction in payroll-related liabilities. Lower accounts payable and accrued liabilities were partially offset by a reduction in accounts receivable consistent with lower retail distribution revenue, a decline in inventory levels as a result of our rationalization program, and an increase in the accrual for employee future benefits other than pension.

Increases in regulatory assets and liabilities, environmental liabilities and the deferred pension asset reported on our balance sheets do not substantially affect our cash flow.

### ***Financing Activities***

Net cash generated from financing activities was \$99 million in 2001 compared with cash used in financing activities of \$679 million in 2000 and \$170 million in 1999. Short-term liquidity is provided through funds from operations and our commercial paper program. We are authorized to issue up to \$1 billion in commercial paper with a term to maturity of less than 365 days. As a back-stop 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 and \$250 million for a five-year term.

At December 31, 2001, we had \$410 million of commercial paper outstanding, resulting in approximately \$590 million of short-term funds available under the commercial paper program.

Long-term financing will be provided by our access to the debt markets including our medium term note program. The maximum authorized principal amount of medium term notes issuable under this program is \$2.5 billion and is currently available until June 2003, at which time we plan to renew the program for an additional two years. We intend to use the medium term note program to meet most of our borrowing requirements for the foreseeable future. At December 31, 2001, we had \$550 million principal amount of medium term notes outstanding, resulting in approximately \$1.95 billion principal amount issuable under this program. We believe that we will be able to issue medium term notes on satisfactory terms, taking into account, among other factors, the investment grade ratings for our long-term senior, unsecured debt from major Canadian and

U.S. rating agencies. Standard & Poor's Rating Services recently downgraded our rating on long-term debt from "AA-" to "A+" and on short-term debt from "A-1+" to "A-1". Dominion Bond Rating Service Inc. confirmed its rating of "A" with a positive outlook. Moody's Investor Services Inc. confirmed its rating of "A1" with a negative outlook.

In 2001, we issued \$550 million in debt under our medium term note program and had a net increase in short-term debt of \$280 million under our commercial paper program. In 2001, we repaid \$474 million of debt payable to Ontario Electricity Financial Corporation. In 2000, the proceeds of our \$1 billion inaugural bond issue, as well as other cash resources, including a net increase of \$130 million in commercial paper, were used to repay \$1,399 million of debt payable to Ontario Electricity Financial Corporation. The financing activities for 1999 were primarily related to first quarter activities of Ontario Hydro.

Our revolving standby credit facility provides, in effect, that a sale by the Province of 50% or more of our voting shares and any resulting downgrading of our ratings for our long-term senior unsecured debt from Moody's below "A3" or Standard & Poor's below "A-" within 30 days following that sale will constitute an event of default under the facility. We do not expect the Offering to result in an event of default under this credit facility.

After completion of the Offering, we believe that primary offerings of new common shares or other equity securities by our company will constitute an additional source of liquidity and capital resources. We could use the proceeds of any future equity offering in the development of our businesses. In addition, to the extent that, consistent with our longer-term strategy, we pursue acquisitions of transmission businesses or assets in North America, we may issue equity securities to fund, or to constitute the consideration paid by us for, any such acquisitions.

## **Risk Management and Quantitative Disclosure Concerning Market Risk**

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 has been mandated to review annually our company's risk tolerances, its risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Investment Review Committee has recently been designated as the executive oversight committee for business risks. Our Chief Financial Officer is responsible for the ongoing monitoring and review of our risk profile and practices and will work in close association with the Investment Review Committee to ensure that the risk management program is an integral part of our business strategy, planning and objectives. Each of our subsidiaries is required to complete a formal risk assessment program and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, the Investment Review Committee and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing holding company and subsidiary 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.

### **Market Risk**

Market risk refers primarily to the risk of loss that results from changes in interest rates, currency exchange rates and commodity prices, chiefly for purchases of power and gas.

All of our long-term debt outstanding at December 31, 2001 is denominated in Canadian dollars and bears interest at various rates, with a weighted-average interest rate of 8.0%. We are exposed to fluctuations in interest rates as maturing debt is refinanced and periodically utilize interest rate swap agreements to mitigate elements of the interest rate risk. At the end of 2001, offsetting interest rate swap agreements with the same counterparties 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 2002 and 2003 would affect net income by \$1.2 million in 2002 and \$4.2 million in 2003. Accordingly, we estimate that a 1% increase in weighted-average interest rates in respect of our indebtedness will not have a material effect

on our results of operations for 2002 or 2003. We cannot make any prediction concerning actual interest rate movements in 2002 or 2003.

Although we are not currently exposed to fluctuations in currency exchange rates, we may decide in the foreseeable future to issue foreign currency debt or to enter into business arrangements concerning foreign operations.

We do not believe that our regulated transmission and distribution businesses will be exposed to commodity risk after Open Access, as the Ontario Energy Board allows all distributors to pass commodity costs through to their customers. We will continue to experience volume risk with the opening of the market. Rates for our transmission and distribution businesses are based on projected electricity consumption levels. A significant reduction in actual consumption levels from projections could negatively affect the rates of return of these businesses. In the event of reductions resulting from unusual circumstances, we could apply to the Ontario Energy Board for a rate redress.

Our activities in the competitive retail market, conducted through our unregulated subsidiary, Ontario Hydro Energy Inc., are exposed to price and volume risks, both of which we intend to manage. These risks arise from different prices, volumes and other conditions in supply contracts as compared to prices negotiated with customers and their actual volume requirements. We intend to limit our exposure to commodity price and volume risk in the competitive retail market through contract-matching techniques and the use of electricity and gas derivative financial instruments. We have entered into electricity swaps with Ontario Power Generation Inc., which are effective upon Open Access for a term of five years. Under these transactions, we will pay fixed prices ranging from \$45 to \$50 per MWh on a total notional volume of 906 GWh and receive a variable price. In addition, total retail electricity sales of approximately 8,500 GWh with sale prices averaging approximately \$59 per MWh remain unhedged. We are pursuing opportunities to enter into full requirements electricity and gas supply contracts with established energy marketing and trading companies. Under such arrangements, the trading company would fulfil actual customer requirements, thereby assuming substantially all of our commodity price and volume risk associated with the provision of energy.

### **Credit Risk**

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Currently, we have no significant concentrations of credit risk with respect to any class of financial assets. Our revenue is earned from a broad base of customers and we currently do not earn a significant amount of revenue from any single customer. However, with the introduction of Open Access, we will be required to procure wholesale power on behalf of competitive retailers and distribution companies connected to our distribution network for resale to their customers. We intend to mitigate the resulting concentrations of credit risk through the use of various security arrangements, including letters of credit, which will be incorporated into our service agreements with these retailers and companies in accordance with the Ontario Energy Board's Retail Settlement Code.

Derivative financial instruments result in exposure to credit risk because of a risk of counterparty default. Other than our interest rate swaps, all of our derivative financial instruments have been entered into by Ontario Hydro Energy Inc. We monitor and attempt to minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties and by entering into master agreements which enable net settlements of obligations between parties.

### **Environmental Risk**

We manage a number of environmental risks that are primarily related to contaminated land, PCBs, spills and leaks. We have developed specific environmental management programs for these risks, including a program to systematically assess and remediate, if necessary, contaminated land and a program to identify and safely destroy or dispose of PCB-contaminated equipment. We also have a program to respond to spills and to reduce the amount of insulating oil leaking from equipment.

We estimate our future expenditures associated with land assessment and remediation and PCB management. As at December 31, 2001, our current estimate for future expenditures associated with land assessment and remediation is approximately \$83 million. For the purpose of this estimate, we assume that remediation will be conducted, as necessary, where contamination exists off-site or poses an on-site risk to human health. We have also assumed that the Ontario Ministry of the

Environment, the Federal Department of Indian Affairs and Northern Development and affected Indian bands will support our approach to assessment and remediation and that existing environmental regulations will not change. As at December 31, 2001, our current estimate of future expenditures for PCB management is approximately \$163 million. This estimate assumes that existing environmental regulations regarding PCB management will not change. Our estimates are reviewed regularly and we currently expect to incur these PCB-related expenditures through to the end of 2020. As at December 31, 2001, our estimated present discounted value for future expenditures under both programs was approximately \$174 million. A regulatory asset in this amount has been established that reflects our expectation of recovery of these expenditures through our future rates.

### **Risks Related to Transfer of Assets on Indian Lands**

We are exposed to financial risk associated with the cost to complete the transfer to our company of title to transmission, distribution and other assets located on Indian lands in connection with the acquisitions of our operations as of April 1, 1999. 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. We manage these assets, which are currently owned by Ontario Electricity Financial Corporation.

We have begun negotiating with the relevant Indian bands and bodies to obtain the consents necessary to complete the transfer of these transmission, distribution and other assets. We cannot predict the total amount that we may have to pay to obtain the required consents. We expect to pay more than the \$850,000 per year that we are currently paying to these Indian bands and bodies and that is the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, we cannot otherwise obtain the consents from the Indian bands and bodies, Ontario Electricity Financial Corporation will continue to hold these assets for an indefinite period of time. Alternatively, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, abandon a line and replace it with diesel generation facilities. In such cases, we would apply to the Ontario Energy Board to recover these payments or costs in future rate orders.

### **Risk of Recovery of Market Ready Costs**

In March 2002, the Ontario Energy Board approved our application to recover approximately \$8 million of the costs we incurred to align our systems and practices with those of the competitive electricity market in Ontario, commonly referred to as Market Ready costs. Total Market Ready costs for our transmission and distribution businesses are estimated to be \$110 million. The process and timing for the approval of the remaining amount spent has not been established, although we expect any recovery of these costs to be over a period of years. We have informed the Ontario Energy Board of this estimate and have deferred the costs for accounting purposes, adhering to the initial criteria established by the Ontario Energy Board. The Ontario Energy Board has the discretion to examine and assess the extent to which these Market Ready costs may be recovered.

### **Related Party Transactions**

Prior to the Offering, the Province owned all of our outstanding common and preferred shares. Upon closing of the Offering, the Province will retain some special voting rights in limited circumstances and may retain an ownership interest. In addition, the Province owns all of our preferred shares, which we are obligated to redeem within 120 days of the closing of the Offering.

As of April 1, 1999, we acquired substantially all of the assets, liabilities, rights and obligations of the electricity transmission, distribution and energy services businesses of Ontario Hydro pursuant to transfer orders under the *Electricity Act, 1998*. Ontario Electricity Financial Corporation has agreed to indemnify us with respect to the failure of the transfer orders to transfer any asset, right or thing or any interest therein related to our business to us and some of our subsidiaries, some adverse claims or interests of third parties or based on title deficiencies arising from the transfer orders, except for some claims and rights of the Crown, and claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgment, settlement or payment in connection with litigation initiated by some utilities commissions. The Province has agreed to unconditionally and irrevocably guarantee to us and our subsidiaries the payment of

all amounts owing by Ontario Electricity Financial Corporation under its indemnity. Ontario Electricity Financial Corporation held approximately \$3 billion of our debt as at December 31, 2001. Ontario Electricity Financial Corporation has advised us that it intends to resell in the Canadian debt capital markets by March 31, 2003 the approximately \$2.5 billion of our debt held by it which matures after 2002. In addition, we have engaged in, and will continue to engage in, transactions with affiliates of the Province, including Ontario Power Generation Inc. The Province also has general policy directive powers over the Ontario Energy Board, which is our principal regulator.

In addition to the foregoing, we have engaged in extensive transactions, and have significant relationships, with the Province and its affiliates and agencies and bodies during the entire period covered by our financial statements and to date. See Note 18 to the Consolidated Financial Statements for the three-year period ended December 31, 2001.

### **Critical Accounting Policies**

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

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

***Regulatory assets and liabilities.*** We operate in a regulated environment. As a result, regulatory assets and liabilities arise as part of the rate-making process. These assets and liabilities can be recognized only to the extent that the Ontario Energy Board accepts the relevant regulatory treatment. If the Ontario Energy Board subsequently determines that a regulatory treatment is no longer acceptable, that regulatory asset or liability would no longer be supportable and, accordingly, would be charged or credited to the statement of operations in the period in which that determination is made. The following items give rise to regulatory assets: employee future benefits other than pension; Market Ready costs incurred to align our systems and practices with the requirements of the future competitive electricity market in Ontario; and estimated future expenditures required to remediate past environmental contamination. Pension costs give rise to regulatory liabilities.

***Environmental liabilities.*** We estimate our total liability for remediation of past environmental contamination and management of PCBs based on the net present value of these estimated future expenditures. We also review estimates of future environmental expenditures on an ongoing basis. These future expenditures are estimated in accordance with current environmental laws and regulations and current estimates of long-term interest rates. If environmental laws and regulations or long-term interest rates change, the net present value of our environmental liabilities will be affected.

***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 transitional rate orders, we record pension costs when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Based on the last actuarial valuation of pension fund assets and liabilities as of December 31, 2000, we have had a contribution holiday and, as such, are not required to make contributions to the pension fund until, at the earliest, the next actuarial valuation, which will occur no later than December 31, 2003.

We record employee future benefits other than pension costs 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. These assumptions include a weighted-average discount rate, the rate of compensation scale escalation, the rate of cost of living increase, the rate of increase in long-term medical costs, as well as the rate of increase in dental costs. 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 current and retired employees covered.

Employee future benefits included in labour costs and charged to operations or are capitalized as part of the cost of fixed assets. Changes in the assumptions will affect the amount of the employee future benefits and the current year charge to the statement of operations or amount capitalized to the cost of fixed assets.

In general, in the event that our estimates and judgments incorporated in the above critical accounting policies differ from actual results, or if the Ontario Energy Board, for any reason, does not allow or accept our accounting treatment reflected in these policies or changes its position in respect of any of these policies, then the resulting effect on our results of operations and financial position could be material.

### **Reconciliation to U.S. GAAP**

Net income was higher under Canadian GAAP by \$4 million in 2001, and \$68 million in 2000 than would be the case under U.S. GAAP. Of the \$68 million difference in 2000, \$60 million was the result of the timing of recognition of costs associated with staff reduction programs. Retained earnings were lower under Canadian GAAP by \$25 million as at December 31, 2001, and by \$29 million as at December 31, 2000 than would be the case under U.S. GAAP. See Note 25 to the Consolidated Financial Statements for the three-year period ended December 31, 2001 for a description of the principal differences between Canadian GAAP and U.S. GAAP, as they pertain to us.

The U.S. Financial Accounting Standards Board, which is commonly referred to as "FASB", issued a series of new accounting pronouncements in 2001. See Note 25 to the Consolidated Financial Statements for the three-year period ended December 31, 2001. Other than as described below, we do not anticipate that these FASB accounting pronouncements will have a material effect on our results of operations or financial position. The effect of Statement of Financial Accounting Standard No. 143, *Accounting for Asset Retirement Obligations*, which relates to the accounting treatment of obligations associated with the retirement of long-lived assets, is not yet determinable, but could be material in terms of our results of operations and financial condition under U.S. GAAP.