RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three and nine months ended September 30, 2005 to the three and nine months ended September 30, 2004.

Revenues

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	**2005**	**2004**	**$ Change**	**% Change**	**2005**	**2004**	**$ Change**	**% Change**
Transmission	356	327	29	9	991	945	46	5
Distribution	818	687	131	19	2,385	2,122	263	12
Other	5	4	1	25	15	12	3	25
	1,179	1,018	161	16	3,391	3,079	312	10
Average Ontario 60-minute peak demand (*MW*)[1]	25,297	23,015	2,282	10	23,312	22,403	909	4
Distribution - units distributed to customers *(TWh)*[1]	7.1	6.6	0.5	8	22.2	21.2	1.0	5

[1] System-related statistics are preliminary

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

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high voltage network. The tariff is designed to recover the necessary revenues to support a transmission system that has sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include a minor amount of ancillary revenues, which are primarily attributable to maintenance services provided to generators and secondary land use related to rights-of-way.

The summer of 2005 was one of the hottest on record, with a new record Ontario peak demand of 26,157 MW reached during June, only to be surpassed in July with a new peak demand of 26,160 MW. The previous record of 25,414 MW was set in August 2002. This record peak demand during the summer months, together with increased peak demand in September, resulted in higher transmission tariff revenues in this quarter as compared to the same period last year. The average peak demand for the first and second quarters of 2005 was also higher than last year, further contributing to increased revenue on a year-to-date basis. Ancillary transmission revenues were marginally lower this year, both in the quarter and year-to-date periods.

Distribution

Distribution revenues include our distribution tariff, which is based on Ontario Energy Board (OEB) approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased in the third quarter and in the first nine months of 2005 compared to the same periods last year, primarily due to the recovery of higher purchased power costs of $111 million and $218 million, respectively, as described below under "Purchased Power." The remaining increases primarily reflect an OEB-approved distribution tariff rate increase effective April 1, 2005, the recognition of low voltage services revenues, and increased demand. The approved tariff increase was originally scheduled to be effective March 1, 2003, but was subsequently suspended for all local distribution companies by the *Electricity Pricing, Conservation and Supply Act, 2002*. During 2004, the low voltage services revenues were deferred until a December 2004 prudence decision by the OEB allowed for regulatory recovery starting in 2005. Ancillary distribution revenues were lower this year both in the third quarter and in the year-to-date periods. Last year we earned revenues attributable to our Florida power restoration efforts, carried out under a North American mutual-assistance agreement.

Other

Other revenues were higher compared to the same periods last year due to increased lit fibre revenues within our telecommunications business.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) wholesale market service charges, and transmission charges levied by the IESO. Prior to April 1, 2004, for certain low volume and designated customers, the commodity price of electricity was fixed at 4.3 cents per kWh. On April 1, 2004, this fixed rate was replaced by an interim two-tiered pricing structure of 4.7 cents per kWh for the first 750 kWh consumed each month and 5.5 cents per kWh for any additional consumption. On April 1, 2005, the interim pricing structure was replaced by the OEB's Regulated Price Plan (RPP) which consists of a two-tiered pricing structure of 5.0 cents per kWh for the first 750 kWh consumed each month and 5.8 cents per kWh for any additional consumption. Effective November 1, 2005 the first 750 kWh threshold will be increased to 1,000 kWh. Customers who are not eligible for the RPP continue to pay market prices for electricity, adjusted for the difference between market price and regulated and contract prices paid to generators under the *Electricity Restructuring Act, 2004*.

Purchased power costs increased by $111 million to $581 million in the third quarter and by $218 million to $1,683 million during the first nine months of 2005 compared to the same periods last year. These increases primarily reflect higher commodity costs of $58 million and $133 million respectively, which were largely due to the implementation of the April 2004 and April 2005 pricing structures for certain low-volume and designated customers, as well as a higher wholesale commodity price for customers who are not eligible for the RPP. The remaining increase is primarily attributable to increased demand for electricity.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

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

	Three months ended September 30				**Nine months ended September 30**			
(Canadian dollars in millions)	**2005**	**2004**	**$ Change**	**% Change**	**2005**	**2004**	**$ Change**	**% Change**
Transmission	91	79	12	15	261	267	(6)	(2)
Distribution	100	77	23	30	288	287	1	-
Other	6	6	-	-	18	16	2	13
	197	162	35	22	567	570	(3)	(1)

Transmission

Operation, maintenance and administration expenditures for our transmission business were $12 million higher in the third quarter, but $6 million lower year-to-date compared to the same periods last year. Higher expenditures were incurred in both periods from the reassignment of resources to support maintenance activities consistent with our smaller capital program this year. The impact of these expenditures was partially offset by cost reductions associated with a labour disruption and reduced outages taken on the transmission system to service equipment to ensure continued system reliability during the periods of unusually high demand this summer. For the first nine months, higher operation, maintenance and administration expenditures were more than offset by cost recoveries associated with insurance settlements and bad debts.

Distribution

Operation, maintenance and administration expenditures for our distribution business increased by $23 million in the third quarter relative to last year, but were substantially consistent on a year-to-date basis. The increase in the quarter reflects last year's recognition of distribution pension contribution costs as a regulatory asset, consistent with the July 2004 OEB approval of our application for a regulatory deferral account. Prior to being recognized as an asset, these costs had been expensed in the first seven months of 2004. On a year-to-date basis, the accounting treatment of distribution pension costs was consistent with the prior year. We also increased our forestry program in the quarter consistent with our planned schedule. These increases were partially offset by lower costs this year resulting from a labour disruption and from providing hurricane assistance to Florida in 2004. For the first nine months, the effect of these lower costs was offset by an increase in facility costs.

Other

Other operation, maintenance and administration costs were unchanged in the quarter and $2 million higher on a year-to-date basis compared to 2004. These results are consistent with the higher level of lit fibre service revenues, partially offset by lower market prices paid for telecommunications services and fibre within our telecommunications business.

Depreciation and Amortization

Depreciation and amortization expense increased by $3 million, or 3%, to $120 million in the third quarter and by $18 million, or 5%, to $361 million in the first nine months relative to the comparative periods. These changes primarily result from increased amortization of regulatory assets related to the OEB's December 2004 regulatory decision to allow recognition of certain assets. Higher fixed assets in service, consistent with the investments made in our electricity delivery network, has also resulted in an increase in depreciation expense.

Financing Charges

Financing charges increased by $3 million, or 4%, to $84 million in the third quarter and decreased by $2 million, or 1%, to $247 million in the first nine months compared to the same periods last year. The increase in the quarter is attributable to higher levels of debt outstanding this year, partially offset by the impact of increased interest capitalization on our regulatory assets as a result of the December 2004 OEB decision. For the nine month period, the impact of higher average debt levels was more than offset by the effects of higher interest capitalization on our regulatory assets.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $9 million, or 16%, to $64 million in the third quarter and by $14 million, or 10%, to $154 million in the first nine months, compared to the same periods in 2004. A higher tax provision, resulting from higher net income for the first nine months of the year, was partially offset by the recognition of a tax benefit of approximately $21 million relating to accumulated tax losses of a subsidiary. The tax benefit was recognized during the second quarter of this year after an agreement was reached to settle an outstanding legal claim that allowed for the dissolution of the subsidiary. The tax provision for the three month period to September 30, 2005 was higher than the same period last year as a result of higher temporary differences in 2004.

Net Income

Net income of $133 million was consistent in the third quarter in 2004, but increased by $67 million or 21%, to $379 million in the first nine months compared to last year. These results reflect higher tariff revenues associated with the large demand on the transmission and distribution systems, as well as the implementation of an OEB-approved distribution rate increase effective April 1, 2005 and the recognition of distribution low voltage services revenues. During this quarter, the higher revenues were offset by increased operation, maintenance and administration costs, including the recognition of a regulatory asset for pension costs in the comparative quarter last year. Results for the nine-month period also reflect a lower effective tax rate than last year as a result of the recognition of the tax benefit from previously unrecognized losses from one of our subsidiaries in the second quarter.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from December 31, 2003 through September 30, 2005. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	**2005**			**2004**				**2003**
Quarter ended	**Sept 30**	**Jun 30**	**Mar 31**	**Dec 31**	**Sept 30**	**Jun 30**	**Mar 31**	**Dec 31**
Total revenue[1,2]	1,179	1,018	1,194	1,074	1,018	960	1,101	1,009
Net income [1,2]	133	115	131	186[3]	133	59	120	79
Net income to common shareholder [1,2]	129	110	127	181	129	55	115	75

[1] Both the revenue and the net income amounts reported in the first and second quarter of 2004 have been reduced by $5 million and $6 million, respectively, to reflect a change in interperiod allocations.

[2] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and net income, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[3] As a result of submitted oral and written evidence, on December 9, 2004 the OEB issued a ruling citing prudence and approving recovery of amounts, previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002,* relating to regulatory deferral account balances sought in our May 31, 2004 submission. Consequently, net income for the fourth quarter of 2004 includes a regulatory recovery of $91 million.

LIQUIDITY AND CAPITAL RESOURCES

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

Summary of Sources and Uses of Cash	**Three months ended September 30**		**Nine months ended September 30**	
(Canadian dollars in millions)	**2005**	**2004**	**2005**	**2004**
Operating activities	344	264	813	748
Financing activities				
Long-term debt issued	-	130	500	500
Long-term debt retired	-	-	(200)	(472)
Short-term notes payable	-	(142)	(40)	(25)
Dividends paid	(72)	(61)	(218)	(203)
Investing activities				
Capital expenditures	(144)	(193)	(481)	(538)
Other investing and financing activities	(12)	(1)	(19)	14
Net change in cash and cash equivalents	116	(3)	355	24

Operating Activities

Net cash generated from operations increased by $80 million in the third quarter and by $65 million over the first nine months compared to the same period in 2004. For the quarter, the change primarily reflects lower working capital requirements, including the impact of a lower capital program this year and the impact of a funding contribution to our pension plan made in September 2004. Subsequent to this initial funding payment, pension contributions have been made each month, one month in arrears. The increase in cash from operating activities for the first nine months of 2005 compared to last year, is primarily attributable to higher net income levels, in particular from higher transmission and distribution tariff revenues.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by committed revolving credit facilities with a syndicate of banks of $750 million which mature in August 2006, with a two-year extension option. As at September 30, 2005, we had no short-term notes outstanding and a cash balance of $346 million, which will be used to retire debt maturing later this year. The available cash, short-term liquidity 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. Our notes and debentures mature between 2005 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 Ratings Services Inc.[1]	A-1	A
Dominion Bond Rating Service Inc.	R-1 (low)	A
Moody's Investors Service Inc.[2]	Prime-1	Aa3

[1] On July 15, 2005, Standard & Poor's Ratings Services Inc. raised Hydro One's short-term debt rating to A-1 from A-2.
[2] On July 8, 2005, Moody's Investors Service Inc. raised Hydro One's long-term debt rating to Aa3 from A2 as a result of its analysis of government-related issuers.

During the third quarter of 2005, we did not issue or retire any long-term or short-term debt. In comparison, during the third quarter of 2004 we issued $130 million in debt under our medium term note program and did not repay any maturing long-term debt. In the third quarter last year we paid down our short-term notes by $142 million. On a year-to-date basis, we have issued $500 million and have retired $200 million in long-term debt compared to issuances of $500 million and retirements of $472 million in 2004. The year-to-date net decrease in short-term notes totalled $40 million, compared to a net decrease of $25 million last year.

In the third quarter of 2005, we paid dividends to the Province of Ontario in the amount of $72 million, consisting of $68 million in common dividends and $4 million in preferred dividends. In the comparative period, we paid common dividends of $57 million and preferred dividends of $4 million. On a year-to-date basis, we have paid common and preferred dividends totalling $218 million, compared to $203 million in 2004.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	**2005**	**2004**	**$ Change**	**% Change**	**2005**	**2004**	**$ Change**	**% Change**
Transmission	53	123	(70)	(57)	229	321	(92)	(29)
Distribution	90	69	21	30	250	212	38	18
Other	1	1	-	-	2	5	(3)	(60)
	144	193	(49)	(25)	481	538	(57)	(11)

Transmission

Transmission capital expenditures decreased by $70 million in the third quarter and by $92 million on a year-to-date basis, compared to the same periods last year. Capital expenditures to expand and reinforce our transmission system were lower by $66 million in the quarter and by $105 million in the first nine months primarily due to the substantial completion of the Parkway Transformation Station this year. This project was initiated last year in response to growing loads and the closure of the Lakeview Generating Station. In 2004, we also completed our Ontario Grid Control Centre. In the quarter, we commenced construction of our Niagara Reinforcement Project. This project, which is in the public interest, includes a new transmission line to alleviate transmission constraints in the Niagara region. The reductions in capital expenditures in the quarter and year-to-date periods were partially offset by higher expenditures to sustain our transmission lines and stations and to maintain reliability, as well as an increased level of investments in information management infrastructure.

Distribution

Distribution capital expenditures increased by $21 million this quarter and by $38 million on a year-to-date basis relative to the comparative periods. These increases are due primarily to increased investments to support our distribution network, including increased expenditures on transport and work equipment and information management infrastructure. Capital expenditures to sustain and develop the low voltage distribution system were generally consistent in both periods, compared to last year.

Other

Other capital expenditures in the third quarter were $1 million, consistent with the same period last year. On a year-to-date basis, other capital expenditures decreased by $3 million to $2 million. The level of expenditures reflects the timing of projects to meet customer demand for new services.

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.

September 30, 2005 (Canadian dollars in millions)	**Total**	**2005[1]**	**2006/2007**	**2008/2009**	**After 2009**
Contractual Obligations *(due by year)*					
Long-term debt	5,532	339	1,093	900	3,200
Inergi LP outsourcing agreement[2]	631	27	208	197	199
Operating lease commitments	18	1	9	7	-
Total Contractual Obligations	6,181	367	1,310	1,104	3,399
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	750	-	750	-	-
Letters of credit[4]	104	83	21	-	-
Guarantees[4]	275	275	-	-	-
Pension[5]	106	18	88	-	-
Total Other Commercial Commitments	1,235	376	858	-	-

[1] The amounts disclosed represent the balance due over the period October 1, 2005 to December 31, 2005.

[2] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[3] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2006, with a two-year term out option.

[4] We currently have bank letters of credit of $80 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $21 million and parental guarantees of $275 million. The amount of prudential support that we provide in the form of bank letters of credit to the IESO 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. For example, if our credit rating declined to BBB+, the amount of bank letters of credit required to meet our prudential support obligation would be two times our current amount, and if our credit rating declined to BB+, the amount of bank letters of credit required to meet our prudential support obligation would be four times the current amount. The remaining letters of credit pertain to operating letters of credit and to surety bonds.

[5] Contributions to the pension fund are made one-month in arrears. 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.

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. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs.

RECENT DEVELOPMENTS

Transmission Rates

On October 26, 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007 and potentially 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding in November 2005, the OEB will consider options to track net income in excess of the OEB-approved returns for the period between January 1, 2006 until the revised transmission rates are implemented. The options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism.

Niagara Tunnel and Niagara Reinforcement Projects

On September 14, 2005, the Government of Ontario (Government) announced that Ontario Power Generation Inc. would be constructing a new tunnel to supply more water from Niagara Falls to the Sir Adam Beck Generating Complex. Our Niagara Reinforcement Project will accommodate the potential 1.6 terawatt hours per year of additional clean energy to be generated by the Niagara Tunnel Project as well as additional electricity imports from New York State. The Niagara Reinforcement Project includes a new 76-kilometre double circuit 230 kilovolt transmission line primarily along existing rights-of-way and is expected to be completed in 2006. Cost recovery will be subject to the provision of evidence to the OEB regarding the economic benefits of this project.

Manitoba Power Purchase Agreement

On October 27, 2005, the Governments of Ontario and Manitoba announced a power sale agreement, the first phase of a potential larger 1,500 to 3,000 MW power sale currently under discussion by the two parties. This first phase of the agreement will begin with a 150 MW power transfer in 2006, growing to an annual 400 MW by 2009 as necessary transmission upgrades are made. We anticipate that upgrades will have to be made to some of our existing facilities and we will continue to monitor developments related to this agreement.

Transmission Infrastructure Investment

On October 14, 2005, the OEB released a staff discussion paper on developing filing requirements for transmission infrastructure investment. The OEB expects to release a final report by year-end. This process will provide guidance on the evidence required for cost recovery associated with transmission projects such as the Niagara Reinforcement Project.

Transmission Licence Compliance

On August 19, 2005, we provided the necessary information requested by the OEB with respect to their review of our best efforts to increase interconnection capacity to neighbouring jurisdictions by approximately 2,000 MW.

Distribution Rates

On August 17, 2005, we filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement of Hydro One Networks' distribution business. On average, customers would see an increase of 6% on their monthly bills starting May 2006. This rate application is currently in the evidentiary phase, with oral hearings expected to commence in January 2006 and an OEB decision anticipated later in the first quarter of 2006.

On August 2, 2005, we also filed a distribution rate application seeking approval for a $3 million increase in the 2006 distribution revenue requirement of Hydro One Brampton Networks Inc. On average, customers would see an increase of 1% on their monthly bills starting May 2006. This rate application follows a separate process with the OEB that is independent from the Hydro One Networks Inc. application.

Energy Conservation Responsibility Act, 2005

On November 3, 2005 the Government introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by 2007, with installation in all homes and small businesses to be complete by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. Local distribution companies, including Hydro One Networks' and Hydro One Brampton's distribution businesses, will own, install, operate and maintain the meters. This program is expected to increase our expenditure levels and reduce our tariff revenues.

Credit on Electricity Bills

On October 20, 2005, the Government announced that residential and small business electricity consumers, schools, hospitals and others covered by the RPP will receive a one-time credit on an upcoming electricity bill. For the period from April 1, 2004 to March 31, 2005, $495 million was accumulated in the Electricity Consumer Price Protection Fund with respect to these consumers. This was a result of the difference between the Government's interim pricing plan and the actual cost of power, which was lower due to the moderate weather in 2004. Necessary preparations to issue the credits are currently underway.

Bruce Power Announcement

On October 17, 2005, the Government announced that an agreement had been signed between the Ontario Power Authority (OPA) and Bruce Power to refurbish and restart Bruce A units 1 and 2. These units will produce an additional 1,500 MW of electricity for Ontario. It is likely that this project, combined with potential development of 1,000 MW of wind generation in the surrounding region, will have significant medium term implications to our transmission investments, requiring investments in the order of $300 million over the 2007 to 2009 period. We will continue to closely monitor these developments.

York Region Supply Plan

On September 30, 2005, the OPA filed its recommendations for supply to York Region with the OEB. To meet short-term needs, the OPA recommended conservation and demand management initiatives along with the construction of a new transformer station in northern York Region and the installation of capacitor banks at existing area stations. To meet long-term needs, the OPA recommended new local peaking generation, procured through an OPA-led request for proposals process, and an additional transformer station. If the OPA is unsuccessful in concluding a generation procurement contract, the OPA has recommended that new transmission supply facilities be constructed.

Labour Negotiations

On September 13, 2005, our Board of Directors accepted the Government's request to accept the findings of the government-appointed mediator's report with respect to the strike by the Society of Energy Professionals. The mediator's report recommended that the outstanding issues in dispute be referred to interest arbitration before the Chair of the Ontario Labour Relations Board. This arbitration hearing commenced on November 8, 2005. All staff returned to work on September 22, 2005.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions) (except as otherwise noted)	**2005**	**2004**	**2005**	**2004**
Net income	133	133	379	312
Net cash from operating activities	344	264	813	748
Capital expenditures	144	193	481	538
Earnings per common share *(Canadian dollars)*	1,289	1,289	3,654	2,989
Earnings coverage ratio[1]			2.84	2.42
Net asset coverage on long-term debt[2]			1.85	1.88
Total debt to capitalization[3]			54%	54%

[1]The earnings coverage ratio has been presented for the twelve months ended September 30, 2005 and September 30, 2004, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends. The earnings coverage ratio for the twelve months ended September 30, 2005, excluding the impact of the $91 million regulatory recovery recognized in 2004 as a result of the OEB's December 9, 2004 rate decision, was 2.60.

[2]The net asset coverage on long-term debt ratio has been presented as at September 30, 2005 and December 31, 2004 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt including current portion.

[3]Total debt to capitalization ratio has been presented as at September 30, 2005 and December 31, 2004 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD LOOKING STATEMENTS AND OTHER INFORMATION

We have included forward-looking statements in this report that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. Any statement contained in this document that is not current or historical is a forward-looking statement. We have based these forward-looking statements on historical experience, current conditions and various assumptions believed to be reasonable in the circumstances. Actual results could differ materially from those projected in the forward-looking statements. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or otherwise.

This management's discussion and analysis is dated as at November 10, 2005. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS **(unaudited)**

(Canadian dollars in millions)	**Three months ended September 30** 2005	2004	**Nine months ended September 30** 2005	2004
Revenues				
Transmission	356	327	991	945
Distribution	818	687	2,385	2,122
Other	5	4	15	12
	1,179	1,018	3,391	3,079
Costs				
Purchased power	581	470	1,683	1,465
Operation, maintenance and administration	197	162	567	570
Depreciation and amortization	120	117	361	343
	898	749	2,611	2,378
Income before financing charges and provision for payments in lieu of corporate income taxes	281	269	780	701
Financing charges	84	81	247	249
Income before provision for payments in lieu of corporate income taxes	197	188	533	452
Provision for payments in lieu of corporate income taxes *(Note 4)*	64	55	154	140
Net income	133	133	379	312
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,289	1,289	3,654	2,989

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS **(unaudited)**

(Canadian dollars in millions)	**Three months ended September 30** 2005	2004	**Nine months ended September 30** 2005	2004
Retained earnings, beginning of period	987	691	887	654
Net income	133	133	379	312
Dividends *(Note 2)*	(72)	(61)	(218)	(203)
Retained earnings, end of period	1,048	763	1,048	763

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**September 30, 2005**	**December 31, 2004**
Assets		
Current assets		
Cash	346	-
Accounts receivable (net of allowance for doubtful accounts)	712	707
Materials and supplies	50	47
	1,108	754
Fixed assets		
Fixed assets in service	15,346	14,940
Less: accumulated depreciation	5,734	5,475
	9,612	9,465
Construction in progress	395	348
	10,007	9,813
Other long-term assets		
Deferred pension asset	467	534
Regulatory assets	431	443
Goodwill	133	133
Long-term accounts receivable and other assets	11	25
Deferred debt costs	23	23
	1,065	1,158
Total assets	12,180	11,725
Liabilities		
Current liabilities		
Bank indebtedness	-	9
Accounts payable and accrued charges	591	630
Accrued interest	99	44
Short-term notes payable	-	40
Long-term debt payable within one year *(Note 3)*	896	539
	1,586	1,262
Long-term debt *(Note 3)*	4,593	4,613
Other long-term liabilities		
Employee future benefits other than pension *(Note 5)*	692	654
Regulatory liabilities	537	576
Environmental liabilities	65	74
Long-term accounts payable and accrued charges	22	22
	1,316	1,326
Total liabilities	7,495	7,201
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,048	887
Total shareholder's equity	4,685	4,524
Total liabilities and shareholder's equity	12,180	11,725

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2005	Three months ended September 30 2004	Nine months ended September 30 2005	Nine months ended September 30 2004
Operating activities				
Net income	133	133	379	312
Adjustments for non-cash items:				
Depreciation and amortization (net of removal costs)	111	109	331	317
Amortization of discount	15	15	45	48
Retail settlement variance accounts	(10)	4	12	20
	249	261	767	697
Changes in non-cash balances related to operating activities	95	3	46	51
Net cash from operating activities	344	264	813	748
Financing activities				
Long-term debt issued	-	130	500	500
Long-term debt retired	-	-	(200)	(472)
Termination of forward sale	-	-	(10)	-
Short-term notes payable	-	(142)	(40)	(25)
Dividends paid	(72)	(61)	(218)	(203)
Other	2	9	1	7
Net cash (used in) from financing activities	(70)	(64)	33	(193)
Investing activities				
Fixed assets	(144)	(193)	(481)	(538)
Other assets	(14)	(10)	(10)	7
Net cash used in investing activities	(158)	(203)	(491)	(531)
Net change in cash and cash equivalents	116	(3)	355	24
Cash and cash equivalents, beginning of period	230	(10)	(9)	(37)
Cash and cash equivalents, end of period	346	(13)	346	(13)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. DIVIDENDS

During the three months ended September 30, 2005, preferred dividends in the amount of $4 million (2004 - $4 million) and common dividends in the amount of $68 million (2004 - $57 million) were declared. During the nine months ended September 30, 2005, preferred dividends in the amount of $13 million (2003 - $13 million) and common dividends in the amount of $205 million (2004 - $190 million) were declared.

3. LONG-TERM DEBT

On May 19, 2005, Hydro One issued notes under the Company's medium term note program. The issues comprised a principal amount of $350 million medium term note with a 31-year term at a coupon rate of 5.36% due May 20, 2036, and a principal amount of $150 million with a coupon rate of 3.95% due on February 24, 2009.

Hydro One enters into forward pay fixed interest rate swap agreements or forward sale agreements of Government of Canada bonds to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions, which in 2004 included a forward interest rate swap agreement with a $100 million notional principal amount to lock in the interest rate of a future issuance planned for 2005, are accounted for as cash flow hedges of anticipated transactions. On January 21, 2005, Hydro One entered into an additional forward interest rate swap agreement to lock in a further $50 million in notional principal related to the planned 2005 issuance. On May 19, 2005, upon debt issuance, the Company paid $10 million to settle the interest rate swap agreements.

4. TAX LOSSES

In May 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it is more likely than not that Hydro One will be able to access the subsidiary's accumulated tax losses and, accordingly, a future tax asset of approximately $21 million was recognized in the second quarter.

5. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended September 30		**Nine months ended September 30**	
(Canadian dollars in millions)	**2005**	**2004**	**2005**	**2004**
Pension				
Net period benefit costs	43	31	130	93
Pension fund contribution	20	16	63	70
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	6	6	22	29
Portion attributable to regulatory assets	4	5	18	21
Charged to results of operations	10	5	23	20

(Canadian dollars in millions)	Three months ended September 30 2005	Three months ended September 30 2004	Nine months ended September 30 2005	Nine months ended September 30 2004
Employee Future Benefits other than Pension				
Net period benefit cost	18	25	66	72
Less: Portion attributable to labour and capitalized as part of fixed assets	9	9	25	27
Charged to results of operations	9	16	41	45

6. SEGMENTED 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.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2005				
Segment profit				
Revenues	356	818	5	1,179
Purchased power	-	581	-	581
Operation, maintenance and administration	91	100	6	197
Depreciation and amortization	59	59	2	120
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	206	78	(3)	281
Financing charges				84
Income before provision for payments in lieu of corporate income taxes				197
Capital expenditures	53	90	1	144
2004				
Segment profit				
Revenues	327	687	4	1,018
Purchased power	-	470	-	470
Operation, maintenance and administration	79	77	6	162
Depreciation and amortization	63	53	1	117
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	185	87	(3)	269
Financing charges				81
Income before provision for payments in lieu of corporate income taxes				188
Capital expenditures	123	69	1	193

Nine months ended September 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2005				
Segment profit				
Revenues	991	2,385	15	3,391
Purchased power	-	1,683	-	1,683
Operation, maintenance and administration	261	288	18	567
Depreciation and amortization	182	175	4	361
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	548	239	(7)	780
Financing charges				247
Income before provision for payments in lieu of corporate income taxes				533
Capital expenditures	229	250	2	481
2004				
Segment profit				
Revenues	945	2,122	12	3,079
Purchased power	-	1,465	-	1,465
Operation, maintenance and administration	267	287	16	570
Depreciation and amortization	178	162	3	343
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	500	208	(7)	701
Financing charges				249
Income before provision for payments in lieu of corporate income taxes				452
Capital expenditures	321	212	5	538

(Canadian dollars in millions)	**September 30, 2005**	**December 31, 2004**
Total assets		
Transmission	6,783	6,785
Distribution	4,956	4,845
Other	441	95
	12,180	11,725

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

7. SUBSEQUENT EVENT

On October 26, 2005, the Ontario Energy Board (OEB) initiated a proceeding to review the Company's transmission rates and to approve revenue requirements for 2006, 2007 and potentially 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding in November 2005, the OEB will consider options to track net income in excess of the OEB-approved returns for the period between January 1, 2006 until the revised transmission rates are implemented. The options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism. The financial impact of this future proceeding is not reasonably determinable at this time.

8. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the September 30, 2005 Consolidated Financial Statements.