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, 2008 to the three and nine months ended September 30, 2007.

Revenues

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	**2008**	**2007**	**$ Change**	**% Change**	**2008**	**2007**	**$ Change**	**% Change**
Transmission	315	307	8	3	912	949	(37)	(4)
Distribution	797	813	(16)	(2)	2,454	2,555	(101)	(4)
Other	14	8	6	75	37	22	15	68
	1,126	1,128	(2)	-	3,403	3,526	(123)	(3)
Average Ontario 60-minute peak demand *(MW)*[1]	23,156	24,730	(1,574)	(6)	22,072	23,542	(1,470)	(6)
Distribution - units distributed to customers *(TWh)*[1]	7.0	7.1	(0.1)	(1)	22.1	22.5	(0.4)	(2)

[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 predominantly consist 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 revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $8 million, or 3%, in the third quarter of 2008, and decreased by $37 million, or 4%, in the first nine months compared to the same periods last year. The average monthly peak demand was lower for both the current quarter and the first nine months resulting in a reduction of transmission revenues of $20 million and $59 million, respectively. We also experienced lower ancillary transmission revenues of approximately $4 million in the quarter, and $2 million in the year-to-date period.

In addition, the Ontario Energy Board's (OEB's) August 16, 2007 decision on our transmission rate application impacted our transmission revenues. In its decision, the OEB approved all of our work program expenditure requirements, but reduced our rate of return on equity from 9.88% to 8.35%. The impact of the OEB's decision, which was effective January 1, 2007, was recognized at the decision date. As a result of the OEB's decision to reduce our rate of return, we experienced a reduction to our transmission revenues of $40 million in the third quarter and $116 million in the year-to-date period compared to the same periods last year.

Further to the August 16, 2007 decision, a new regulatory liability, the Revenue Difference Deferral Account (RDDA), was recorded to reflect excess amounts recovered from customers. This account, together with the OEB's transmission Earnings Sharing Mechanism (ESM) that was put in place to equally share 2006 excess transmission earnings between our customers and shareholder, is being repaid to customers over the period November 1, 2007 to December 31, 2008. As a result, our revenues reflect adjustments of $72 million as compared to the third quarter of last year, and $140 million in the year-to-date period, as 2008 rates include a refund of amounts previously recorded as revenue reductions in the ESM in 2006 and RDDA in 2007.

On August 28, 2008, the OEB approved our application to adjust uniform transmission rates, effective January 1, 2009, to reflect the 2008 OEB-approved revenue requirement given the full repayment to customers of the ESM and RDDA.

Distribution

Distribution revenues include our distribution tariff, which is based on 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 decreased by $16 million, or 2%, to $797 million in the third quarter and by $101 million, or 4%, to $2,454 million during the first nine months compared to the same periods last year. These reductions primarily reflect lower purchased power cost recoveries of $7 million in the quarter and $91 million in the first nine months, as described below under "Purchased Power." In addition, revenues associated with the recovery of certain distribution-related deferral account balances ceased effective March 31, 2008, which resulted in lower revenues of $5 million in the quarter and $10 million on a year-to-date basis. Lower energy consumption, resulting primarily from the milder weather this year, reduced our distribution revenues by a further $5 million in the quarter and $6 million in the year-to-date period. These reductions were marginally offset by increases of $1 million in the third quarter and $6 million on a year-to-date basis as a result of the OEB's decisions on smart meters and tariff rates for our subsidiaries Hydro One Networks Inc. and Hydro One Brampton Networks Inc.

We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in the current OEB formula for determining our rate of return on equity would reduce our Transmission Business' results of operations by approximately $20 million and our Distribution Business' results of operations by approximately $13 million.

Other

Other revenues increased by $6 million, or 75%, in the quarter and by $15 million, or 68%, in the year-to-date period as a result of higher revenues in our Telecom Business derived from a newly constructed dedicated network providing secure, high capacity connectivity across numerous health care locations in Ontario.

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's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

Summary of RPP				
	Tier Threshold (kWh)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2
November 1, 2007	1,000	750	5.0	5.9
May 1, 2008	600	750	5.0	5.9

hydroOne

Purchased power costs decreased by $7 million, or 1%, to $526 million in the third quarter and by $91 million, or 5%, to $1,605 million during the first nine months, compared to the same periods last year. Our decreased purchased power costs were primarily due to lower costs associated with the OEB's RPP for residential and other eligible customers of $10 million in the quarter and $65 million in the year-to-date period, lower demand for electricity of $14 million in the quarter and $42 million in the first nine months, and the impact of lower charges levied by the IESO of $1 million in the quarter and $21 million in the year-to-date period, including transmission charges due to the OEB's August 16, 2007 transmission rate decision and wholesale market service charges. These reductions were partially offset by higher wholesale commodity prices for customers who are not eligible for the RPP of $18 million in the quarter and $37 million in the year-to-date period.

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)	**2008**	**2007**	**$ Change**	**% Change**	**2008**	**2007**	**$ Change**	**% Change**
Transmission	104	117	(13)	(11)	306	323	(17)	(5)
Distribution	139	137	2	1	392	410	(18)	(4)
Other	13	9	4	44	34	23	11	48
	256	263	(7)	(3)	732	756	(24)	(3)

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $13 million, or 11%, in the quarter and by $17 million, or 5%, on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued our investments that support the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were lower by $12 million in the quarter and by $3 million for the first nine months compared to the prior year. These reductions were primarily attributable to lower expenditures on our planned station maintenance program, lower requirements for unplanned corrective maintenance, particularly for power equipment, and lower forestry expenditures. Lower expenditures from last year were partially offset by higher station-related planned corrective maintenance, increased planned line maintenance and the impact of reassigning resources in support of our larger capital work program. In addition, we experienced a $1 million and $14 million reduction in our expenditures incurred in support of the transmission system in the third quarter and first nine months of the year, respectively. The year-over-year change was primarily a result of a one-time settlement credit associated with our transfer of pension assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services Commission of Ontario in the first quarter of this year.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $2 million, or 1%, in the third quarter and decreased by $18 million, or 4%, on a year-to-date basis, relative to the comparative periods. Our work program expenditures were marginally higher by $1 million in the quarter and lower by $12 million for the first nine months compared to the prior year. The year-to-date reduction in work program expenditures primarily resulted from lower conservation and demand management (CDM) program expenditures following satisfying OEB program spending requirements associated with accessing our third phase Market Adjusted Rate of Return rates. We continue our involvement in CDM programs, which are now primarily funded by the Ontario Power Authority (OPA). We also experienced lower expenditures from the recognition, in the second quarter of 2007, of deferred smart meter expenditures originally incurred in the 2005 to 2007 period. These expenditures were recognized as a result of the OEB's August 8, 2007 decision regarding the combined smart meter proceeding. Such expenditures are now recognized as incurred. We continue to participate in OPA-funded CDM programs. These programs include the Electricity Retrofit Incentive Program, the Peaksaver Program, and the Great Refrigerator Roundup Program. The reductions in our expenditures for the first nine months were partially offset by higher expenditures associated with increased storm restoration and trouble call

activity in the first nine months of the year, partially offset by lower planned line maintenance work. We also experienced higher support expenditures of $1 million in the quarter, and lower expenditures in support of our distribution business of $6 million on a year-to-date basis, primarily as a result of the Inergi pension asset transfer settlement in the first quarter.

Other

Other operation, maintenance and administration expenditures increased by $4 million in the quarter and by $11 million over the first nine months compared to the same periods last year. These increases were primarily attributable to higher expenditures to support increased revenues from our newly constructed dedicated network.

Depreciation and Amortization

Depreciation and amortization expense increased by $9 million, or 7%, to $137 million in the quarter and by $17 million, or 4%, to $399 million in the first nine months relative to the comparative periods in 2007. These increases were mainly attributable to increased depreciation expense related to the placement of new assets in service consistent with our ongoing capital work program. The impact of these increases was partially offset by the completion of amortization of a regulatory asset related to a distribution deferral account in the first quarter.

Financing Charges

Financing charges decreased by $3 million, or 4%, to $73 million in the quarter and decreased by $6 million, or 3%, to $217 million on a year-to-date basis compared to the same periods in 2007. The change in financing charges for the year-to-date period was due to increased interest income resulting from a higher average level of investments, a $6 million interest credit related to the Inergi pension asset transfer settlement in the first quarter, and an increase in interest capitalized on construction in progress which also impacted the quarter. The impact of these reductions in both the quarter and the year-to-date period was partially offset by an increase in interest expense reflecting a higher average level of debt, partially offset by lower average interest rates.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $39 million, or 64%, to $22 million in the third quarter and decreased by $77 million, or 48%, to $83 million on a year-to-date basis, compared to the same periods last year. The decreases were primarily due to a reduction in the statutory tax rate from 36.12% to 33.50% in addition to net temporary differences, including capital cost allowance in excess of depreciation, as well as higher taxes payable in the prior year on transmission amounts received but not recognized as revenue for accounting purposes. On a year-to-date basis, lower pre-tax income also contributed to the decrease.

Net Income

Net income of $112 million in the third quarter and $367 million on a year-to-date basis was higher by $45 million, or 67%, and higher by $58 million, or 19% respectively, compared to 2007 results. These increases in net income were primarily due to a reduction in our payments in lieu of corporate income taxes resulting from a lower effective tax rate and other net temporary differences. In the year-to-date period, our net income was further impacted by the pension asset transfer settlement with our service provider Inergi following approval from the Financial Services Commission of Ontario in the first quarter. The impact of these factors was partially offset in the year-to-date period by lower transmission revenues resulting from lower average monthly peak demands and the impacts associated with the August 16, 2007 transmission rate decision.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from December 31, 2006 through September 30, 2008. 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)	2008			2007				2006
Quarter ended	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**[2]	**Jun. 30**	**Mar. 31**	**Dec. 31**
Total revenue[1]	1,126	1,055	1,222	1,129	1,128	1,120	1,278	1,142
Net income[1]	112	98	157	90	67	93	149	101
Net income to common shareholder[1]	108	93	153	85	63	88	145	96

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

[2] As a result of the OEB's August 16, 2007 decision on our transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%. Revenues in the third quarter of 2007 reflect a $38 million adjustment to revenues in respect of the period January 1, 2007 to August 16, 2007 and reflect the OEB's decision to reduce the rate of return and revise the capital structure of our Transmission Business.

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 resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, 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)	**2008**	**2007**	**2008**	**2007**
Operating activities	363	335	850	878
Financing activities				
Long-term debt issued	-	-	550	400
Long-term debt retired	-	(73)	(540)	(355)
Short-term notes payable	34	85	159	100
Dividends paid	(72)	(72)	(186)	(252)
Investing activities				
Capital expenditures	(321)	(275)	(835)	(765)
Other financing and investing activities	3	-	14	8
Net change in cash and cash equivalents	7	-	12	14

Operating Activities

Net cash from operating activities increased by $28 million, to $363 million in the third quarter, and decreased by $28 million to $850 million in the first nine months compared to 2007 results. Net cash from operating activities increased in both periods as a result of higher net income and lower working capital requirements, compared to the same periods last year. The increase in the nine-month period was more than offset by the impact of disposing of certain regulatory accounts, primarily the RDDA.

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. At September 30, 2008, we had notes payable with face value of $160 million outstanding. Our commercial paper program is supported by a $1 billion committed revolving credit facility with a syndicate of banks maturing August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At September 30, 2008, we had $5,625 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2009 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $1,650 million is remaining and currently available until July 2009.

Rating Agency	Rating: Short-term Debt	Rating: Long-term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $1 billion credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations as at September 30, 2008.

We did not issue any long-term debt in the third quarters of 2008 and 2007, but there were debt maturities of $73 million in the third quarter of 2007. For the third quarter of 2008, we increased our short-term notes outstanding by $34 million compared to an increase of $85 million for the same period in 2007.

During the first nine months of 2008, we issued $550 million in long-term debt under our Medium-Term Note Program, repaid $540 million in maturing long-term debt, and increased our short-term notes by $160 million. In comparison, during the same period in 2007, we issued $400 million in long-term debt under our Medium-Term Note Program, repaid $355 million in maturing long-term debt, and increased our short-term notes by $101 million.

In the third quarters of 2008 and 2007, we paid dividends to the Province of Ontario (the Province) in the amount of $72 million, consisting of $68 million in common dividends and $4 million in preferred dividends. In the first nine months of 2008, we paid dividends to the Province in the amount of $186 million, consisting of $173 million in common dividends and $13 million in preferred dividends. In the comparative period last year, we paid common dividends of $239 million and preferred dividends of $13 million. In addition, we recorded payments in lieu of corporate income taxes to the Province of $83 million in the first nine months of the year.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

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)	2008	2007	$ Change	% Change	2008	2007	$ Change	% Change
Transmission	179	144	35	24	439	394	45	11
Distribution	139	126	13	10	387	355	32	9
Other	3	5	(2)	(40)	9	16	(7)	(44)
	321	275	46	17	835	765	70	9

Transmission

Transmission capital expenditures increased by $35 million, or 24%, to $179 million in the third quarter, and by $45 million, or 11%, to $439 million in the first nine months, compared to the same periods in 2007. Expenditures made to expand and reinforce our transmission system were $75 million in the quarter and $186 million for the first nine months of the year, representing a $3 million increase in the third quarter and a $22 million reduction for the first nine months of the year, compared to the same periods in 2007. The reduction for the year-to-date period is attributable to a number of significant generation, load connection, and lines and stations projects being completed or substantially completed last year, while other

new projects are still in their initial stages of development. Expenditures on our generation projects are considerably lower, mainly due to reduced expenditures on our Lambton Transformer Station which is expected to be completed early next year.

Expenditures on our lines and stations development projects have remained relatively consistent, with expenditures on new projects being offset by the completion of other large projects. We completed our construction phase of an interconnection project with Québec that will increase access to emission-free hydroelectric power. Further reductions were experienced on our Cambridge Preston Transformer Station Project which has been substantially completed, and on our Downtown Toronto Cable Project which was completed last year. These reductions were offset by increased expenditures on our Essa Transformer Station to Stayner Transformer Station connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers, our Bruce to Milton Transmission Reinforcement Project to connect redeveloped nuclear and wind generation sources in the Huron-Grey-Bruce area, and our Greater Toronto Area (GTA) West Transmission Reinforcement Project, which will increase capacity in the Western GTA to ensure supply reliability in the area. We also experienced reduced expenditures on our Niagara Reinforcement Project, final completion of which continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available. We experienced net lower expenditures on our major load connection projects, due to last year’s substantial completion of work on our Whitby and London Talbot transformer stations and reductions in expenditures on several smaller load connection projects. These reductions were partially offset by increased load connection work at a number of transformer stations including our Pleasant and Kingston Gardiner transformer stations.

Expenditures to sustain our existing transmission system were $72 million in the quarter and $176 million on a year-to-date basis, representing increases of $17 million and $30 million respectively, compared to the same periods last year. These increases were primarily due to expenditures related to the refurbishment and replacement of end-of-life equipment at our Claireville Transformer Station to improve reliability and to meet growing demands. Our other transmission capital expenditures were $32 million in the quarter and $77 million for the first nine months, representing respective increases of $15 million and $37 million from the comparative periods. These increases were attributable to higher information technology expenditures primarily related to an entity-wide information system improvement project to replace end-of-life systems and improve productivity, for which we have completed the first phase, combined with higher expenditures associated with the ramping up of information security enhancements at our Ontario Grid Control Centre.

Distribution

Distribution capital expenditures increased by $13 million, or 10%, to $139 million in the third quarter and by $32 million, or 9%, to $387 million for the first nine months, compared to the same periods in 2007. Capital investments to expand and reinforce our distribution network were $68 million in the quarter and $192 million for the first nine months of the year, representing respective increases of $11 million and $26 million over the comparable periods. These increases primarily reflect ongoing investments in our Smart Meter Program. We have initiated pilots to support the development of a smart grid that would transform the distribution network. During the quarter, we installed approximately 137,000 meters, bringing our cumulative program total of smart meters deployed to about 662,000. The impact of these increases was partially offset by lower expenditures for new customer connections and other small development projects.

Expenditures to sustain our distribution system of $61 million in the quarter and $156 million year-to-date, increased by $5 million and $4 million, respectively, compared to the same periods last year. Higher expenditures for the third quarter were primarily a result of higher costs related to line relocation work and investments in transport and work equipment, partially offset by a reduction in unplanned equipment replacements and lower expenditures on our planned line work programs. Our other distribution capital expenditures decreased by $3 million to $10 million in the third quarter and increased by $2 million to $39 million in the first nine months compared to the same periods in 2007. Other distribution capital expenditures were lower in the quarter and higher for the year-to-date period reflecting the completion of phase one of our entity-wide information system improvement project.

Other

Other capital expenditures made to enhance our telecom infrastructure decreased by $2 million to $3 million and by $7 million to $9 million in the quarter and year-to-date periods, respectively, relative to last year. These reductions were largely due to the substantial completion of a dedicated network providing secure, high capacity connectivity across numerous healthcare locations in Ontario.

Future Capital Expenditures

Our capital expenditures in 2008 are budgeted at approximately $1.4 billion. The 2008 capital budgets for our transmission and distribution businesses are about $800 million and $600 million respectively. Our capital expenditures are expected to exceed $1.5 billion in both 2009 and 2010, primarily reflecting increasing investments to expand, refurbish or replace transmission infrastructure. Our overall investment levels reflect transmission infrastructure requirements consistent with government policy, OPA planning information as set out in its Integrated Power System Plan (IPSP), local area supply requirements and preventive and corrective maintenance requirements to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007. An entity-wide information system improvement project to replace end-of-life systems and increase productivity is also underway. Capital expenditures of our other business segment are budgeted at about $11 million in 2008, about half of the 2007 level, for the completion of a dedicated network that was initiated in 2007.

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, 2008 (Canadian dollars in millions)	**Total**	**2008[1]**	**2009/2010**	**2011/2012**	**After 2012**
Contractual Obligations *(due by year)*					
Short-term notes payable	160	160	-	-	-
Long-term debt – principal repayments	5,625	-	800	1,100	3,725
Long-term debt – interest payments	5,169	115	606	524	3,924
Inergi LP outsourcing agreement[2]	319	28	187	104	-
Operating lease commitments	15	2	9	3	1
Total Contractual Obligations	11,288	305	1,602	1,731	7,650
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	1,000	-	1,000	-	-
Letters of credit[4]	99	98	1	-	-
Guarantees[4]	325	325	-	-	-
Pension[5]	126	24	102	-	-
Total Other Commercial Commitments	1,550	447	1,103	-	-

[1] The amounts disclosed represent the balances due over the period October 1, 2008 to December 31, 2008.

[2] On March 1, 2002, Inergi 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 $1 billion revolving standby credit facility with a syndicate of banks which matures in August 2010.

[4] We currently have bank letters of credit of $95 million outstanding relating to retirement compensation arrangements. The other $4 million included in letters of credit pertains to operating letters of credit and to surety bonds. We have also provided prudential support to the IESO on behalf of our subsidiaries, as required by the Market Rules, using parental guarantees of up to a maximum of $325 million. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2008 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2008 and 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

The amounts in the above table under 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 are recorded under operation, maintenance and administration costs on our Statement of Operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

CRITICAL ACCOUNTING ESTIMATES

Environmental Liabilities

During the quarter we recorded additional environmental liabilities and regulatory assets based on new regulations published by Environment Canada. We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with polychlorinated biphenyl (PCB) laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. Future estimated land assessment and remediation expenditures are expected to be incurred over the period ending 2015 and are discounted using factors ranging from 4.9% to 6.25%. Consistent with the requirements of Environment Canada’s final PCB regulations issued on September 17, 2008, estimated future PCB expenditures are expected to be incurred over the period ending 2025. The new regulations have resulted in an increase to our estimated future expenditures of approximately $265 million, which represents an increase of $195 million to environmental liabilities on a present value basis. The future expenditures for managing PCB issues are discounted using factors ranging from 5.14% to 6.25%.

Recording a liability now for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, the number of assets, oil volumes and contamination levels of equipment with PCBs. All factors used in deriving our environmental liabilities represent management’s best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian Generally Accepted Accounting Principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. At this time, the impact on our future financial position and results of operations is not reasonably determinable or estimable.

We commenced our IFRS conversion project in 2007 and we have established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management from finance, information technology, treasury and our operations organizations, among others. Regular reporting is provided to our senior executive management and to the Audit and Finance Committee of our Board of Directors. We have also engaged an external expert advisor.

Our project consists of four phases: diagnostic; design and planning; solution development; and implementation. We have completed the diagnostic phase, which involved a high level review of the major differences between current Canadian GAAP and IFRS. Currently, we have determined that the areas of accounting difference with the highest potential to impact our company are rate regulated accounting, accounting for fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

We are currently engaged in the design and planning and the solution development phases of our project. We are working in issue-specific teams to focus on generating options and making recommendations in the identified areas. During the design

and planning phase, we have established a staff communication plan, begun to roll out our staff training programs, and have begun to evaluate the impacts of the IFRS transition on other business activities including our subsidiaries. In addition we have been involved in documenting the high impact areas identified, including an analysis of financial system impacts, the establishment of key milestones and ongoing discussions with our external auditors. The impact on disclosure controls and internal controls over financial reporting will also be determined.

The OEB has also begun its own IFRS project to determine the nature of any changes that should be made in regulatory reporting requirements in response to IFRS. On May 8, 2008, the OEB announced the creation of an IFRS Consultation which will provide an opportunity for Board staff to work with industry participants to identify transition issues and suggest how those issues might be addressed. We have participated in each of the Consultation meetings, as well as provided comments on the OEB transition plan. We intend to closely monitor any International Financial Reporting Interpretations Committee (IFRIC) initiatives with the potential to impact rate regulated accounting under IFRS and will participate in any related processes, as appropriate.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

We are in the process of transitioning our major financial systems to an SAP enterprise-wide platform. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

On June 2, 2008, we implemented the first phase of the transition including the supply chain, asset, and work management modules within SAP. A portion of the Financial Accounting and Controlling modules were also implemented to facilitate financial reporting. This implementation included both new controls over Internal Controls over Financial Reporting and replaced controls in the previous information technology system. Our process documentation has been updated and certain controls have been tested for purposes of determining whether they have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

The second phase of the transition, which is planned for implementation in August, 2009, involves the replacement of existing finance, human resources and pay modules within SAP.

RECENT DEVELOPMENTS

Environmental Liabilities

On September 17, 2008, Environment Canada published final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999* and provide the timelines for the disposal of certain types of equipment based on the PCB contamination thresholds. We are reviewing our plan to comply with the new regulations, and we have increased the amount of our environmental liabilities and related regulatory assets by approximately $195 million.

Status of Applications to Construct Facilities

On September 15, 2008, the OEB released its decision approving our leave-to-construct application for our Bruce to Milton Transmission Reinforcement project. The OEB noted that its approval is subject to a number of conditions, notably an Environmental Assessment (EA) approval. Work is continuing on the EA and a final report is expected to be submitted to the Ministry of the Environment later this year, with a decision anticipated in early 2009.

On August 14, 2008, the OEB issued a decision approving our leave-to-construct application for our Vanessa to Norfolk Transmission reinforcement project which includes the upgrade to an existing 115kV single-circuit line and the addition of a second 115kV transmission circuit. The facilities are required to increase the adequacy of electricity supply and improve the reliability of electricity service in Norfolk County. The targeted in-service date is April 2009.

Shareholder Directive

In accordance with a Memorandum Agreement between Her Majesty the Queen in Right of the Province of Ontario as Represented by the Minister of Energy and Infrastructure (our "Shareholder") and our Company dated March 27, 2008, our Shareholder made a declaration pursuant to section 108 of the *Business Corporations Act* (Ontario) pertaining to off-shoring of Inergi jobs under an outsourcing arrangement (the "Inergi Agreement"). The declaration, effective September 24, 2008, allows our Shareholder to assume all decision-making power in respect of the off-shoring of jobs under the Inergi Agreement and removes these powers from our Board of Directors. The directors and officers of our Company are charged with carrying out the intention of the Shareholder Directive. The declaration has been filed on SEDAR and can be accessed at www.sedar.com.

Transmission Rate Applications

On August 28, 2008, the OEB issued its decision for our Transmission Business approving our application to adjust Uniform Transmission rates (UTRs) effective January 1, 2009. This increase will result in UTRs consistent with the OEB-approved 2008 revenue requirement, representing an average increase of less than 1% on an average residential customer's total bill.

On September 30, 2008, we filed a rate application for 2009 and 2010 transmission rates. The application seeks the approval for a revenue requirement of approximately $1,233 and $1,341 million for 2009 and 2010, respectively. This represents an estimated increase on an average residential customer's total bill of less than 1% in each of 2009 and 2010. This application provides required funding for infrastructure renewal and government policy decisions. We anticipate a decision in the second quarter of 2009.

Distribution Rate Applications

In 2007, we filed a cost of service application with the OEB for our Distribution Business. Final arguments were submitted in August 2008 and a decision is pending.

On August 29, 2008, we filed a cost of service application with the OEB for our subsidiary Hydro one Remote Communities Inc. Our application seeks the approval of an approximate $45 million revenue requirement, resulting in an increase in an average customer's total bill of approximately 4% due to increased fuel costs. On September 8, 2008, the OEB issued its letter acknowledging receipt of our application and noting its expectation to render a decision by April 21, 2009.

Financial Markets Exposure

The current financial market turmoil has not impacted the operations of our Company nor our ability to arrange sufficient and cost effective debt financing. In November, 2008, we successfully issued $400 million of debt under our medium term note program.

Our Pension Fund (the Fund) has exposure from its investments in domestic and international equity markets, as well as in fixed income markets. As a result, the Fund has been negatively impacted, consistent with levels experienced in the financial market. The overall exposure of the Fund reflects its broad holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives. The next actuarial funding valuation is required effective December 31, 2009, for contributions commencing 2010. While the required level of contributions will depend on future investment returns, interest rates, changes in benefits and changes in other actuarial assumptions, we do not anticipate any material adverse effect on our business.

3rd Generation Incentive Regulation Mechanism (IRM)

In September 2008, the OEB finalized its policies and formulaic approach to 3rd Generation IRM. The OEB-approved formula adjusts re-based rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in-service beyond a prescribed threshold. On November 7, 2008, we filed our incentive regulation application for our Distribution Business for the 2009 rate year.

Purchases and Sales of Electricity Distributors

On October 14, 2008, the Government of Ontario extended the exemption from the electricity transfer tax to October 16, 2009. This exemption provides publicly-owned electricity distributors with relief from paying the tax when they sell electricity assets to other publicly-owned electricity distributors in Ontario. We remain committed to a prudent and measured approach to distribution rationalization and we will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis, where they are consistent with our strategy and direction from our shareholder.

Government Directive on Renewable Energy and Conservation

On September 17, 2008, the Government of Ontario directed the OPA to review a modest portion of its proposed IPSP focusing on renewable energy and conservation. The review and approval of the IPSP was the subject of an oral hearing before the OEB, but on October 2, 2008 the hearing was adjourned on the basis that it would be premature to continue with the hearing until such time as the OPA re-files a revised IPSP based on the government's directive. The OPA is expected to file a revised IPSP in the first part of 2009, and in the interim, the OEB has requested that the OPA submit a written status on the plan updates and proposed a timeline of November 30, 2008.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions) (except as otherwise noted)	**2008**	**2007**	**2008**	**2007**
Net income	112	67	367	309
Net cash from operating activities	363	335	850	878
Capital expenditures	321	275	835	765
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,073	618	3,534	2,952
Earnings coverage ratio[1]			2.59	2.68
Net asset coverage on long-term debt[2]			1.90	1.87
Total debt to capitalization[3]			53%	53%

[1]The earnings coverage ratio has been presented for the twelve months ended September 30, 2008 and September 30, 2007, 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.

[2]The net asset coverage on long-term debt ratio has been presented as at September 30, 2008 and December 31, 2007 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, 2008 and December 31, 2007 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures, revenue requirements and impacts on customers' bills in both our transmission and distribution businesses and the timing of submissions of applications and decisions from the OEB and other governing bodies; the estimated impact of changes in the forecast long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; statements regarding our future liquidity and capital resources; expectations regarding our financing activities; expectations regarding the results of our projects and completion dates; statements regarding future capital expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; statements regarding future pension contributions; statements about IFRS and our conversion to IFRS; our plan to address the new Environment Canada regulations governing the management, storage and disposal of PCBs; and expectations regarding the timing and amount of additional estimated future environmental expenditures. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and

results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the timing and result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk that we are not able to arrange sufficient financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with changes in the forecast long-term Government of Canada bond yield;
- the number and volume of PCB-contaminated assets identified, the extent of asset contamination and future interest rates and inflation; and
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2007 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at November 13, 2008. 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 AND COMPREHENSIVE INCOME (unaudited)

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2008**	**2007**	**2008**	**2007**
Revenues				
Transmission	315	307	912	949
Distribution	797	813	2,454	2,555
Other	14	8	37	22
	1,126	1,128	3,403	3,526
Costs				
Purchased power	526	533	1,605	1,696
Operation, maintenance and administration *(Note 4)*	256	263	732	756
Depreciation and amortization	137	128	399	382
	919	924	2,736	2,834
Income before financing charges and provision for payments in lieu of corporate income taxes	207	204	667	692
Financing charges *(Note 4)*	73	76	217	223
Income before provision for payments in lieu of corporate income taxes	134	128	450	469
Provision for payments in lieu of corporate income taxes	22	61	83	160
Net income	112	67	367	309
Other comprehensive income	-	(1)	(1)	-
Comprehensive income	112	66	366	309
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,073	618	3,534	2,952

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2008**	**2007**	**2008**	**2007**
Retained earnings, beginning of period	1,399	1,246	1,258	1,184
Net income	112	67	367	309
Dividends *(Note 5)*	(72)	(72)	(186)	(252)
Retained earnings, end of period	1,439	1,241	1,439	1,241

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2008**	**2007**	**2008**	**2007**
Accumulated other comprehensive income, beginning of period	(10)	(11)	(9)	(12)
Other comprehensive income	-	(1)	(1)	-
Accumulated other comprehensive income, end of period	(10)	(12)	(10)	(12)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**September 30, 2008**	**December 31, 2007**
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts) *(Note 2)*	682	759
Regulatory assets *(Note 3)*	58	103
Materials and supplies *(Note 2)*	26	27
Other	14	17
	780	906
Fixed assets		
Fixed assets in service *(Note 2)*	17,194	16,743
Less: accumulated depreciation	6,474	6,220
	10,720	10,523
Construction in progress	938	622
Future use land, components and spares *(Note 2)*	114	109
	11,772	11,254
Long-term assets		
Deferred pension asset	425	380
Regulatory assets *(Note 3)*	290	110
Goodwill	133	133
Long-term accounts receivable and other assets *(Note 2)*	7	7
	855	630
Total assets	13,407	12,790
Liabilities		
Current liabilities		
Bank indebtedness	-	12
Accounts payable and accrued charges	710	731
Regulatory liabilities	37	114
Accrued interest	95	55
Short-term notes payable	159	-
Long-term debt payable within one year	400	540
	1,401	1,452
Long-term debt *(Note 6)*	5,224	5,063
Other long-term liabilities		
Regulatory liabilities	573	469
Employee future benefits other than pension	895	855
Environmental liabilities *(Note 3)*	236	52
Long-term accounts payable and other liabilities	12	13
	1,716	1,389
Total liabilities	8,341	7,904
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Total share capital	3,637	3,637
Retained earnings	1,439	1,258
Accumulated other comprehensive income	(10)	(9)
Total retained earnings and accumulated other comprehensive income	1,429	1,249
Total shareholder's equity	5,066	4,886
Total liabilities and shareholder's equity	13,407	12,790

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**		**Nine months ended September 30**	
	2008	**2007**	**2008**	**2007**
Operating activities				
Net income	112	67	367	309
Adjustments for non-cash items:				
Depreciation and amortization (net of removal costs)	126	119	367	350
Revenue difference deferral account	(18)	76	(56)	76
Retail settlement variance accounts	2	8	44	24
Other regulatory asset and liability accounts	4	(24)	(8)	(6)
Amortization of discount	(1)	-	-	6
	225	246	714	759
Changes in non-cash balances related to operations	138	89	136	119
Net cash from operating activities	363	335	850	878
Financing activities				
Long-term debt issued	-	-	550	400
Long-term debt retired	-	(73)	(540)	(355)
Short-term notes payable	34	85	159	100
Dividends paid	(72)	(72)	(186)	(252)
Other	3	-	10	(1)
Net cash used in financing activities	(35)	(60)	(7)	(108)
Investing activities				
Capital expenditures	(321)	(275)	(835)	(765)
Other assets	-	-	4	9
Net cash used in investing activities	(321)	(275)	(831)	(756)
Net change in cash and cash equivalents	7	-	12	14
Cash and cash equivalents, beginning of period	(7)	(15)	(12)	(29)
Cash and cash equivalents, end of period	-	(15)	-	(15)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These 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) for the year ending December 31, 2007 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, except as described below in Note 2.

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. ACCOUNTING CHANGES

Change in Accounting Policy – Inventory

Effective January 1, 2008, the Company retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3031, *Inventories,* with reclassification of comparative prior period amounts. This new section requires that certain major spare parts and standby equipment be reclassified from inventory to fixed assets. The new Handbook section also allows previously recorded impairment losses taken on inventory to be reversed if there is evidence that the net realizable value has subsequently recovered.

The Company already includes certain major standby equipment as in-service fixed assets and depreciates these assets over their useful lives. Upon adoption of the new section in the first quarter of 2008, the Company reclassified approximately $42 million (2007 - $40 million) in asset components and equipment previously classified as materials and supplies inventory. Concurrent with the above reclassification, the Company also reclassified future use land with a carrying value of approximately $69 million (2007 - $69 million) from "fixed assets in service" to "future use land, components and spares." Future use land, components and spares are not depreciated until they are transferred to active capital projects and those projects are placed in-service.

Change in Capital Disclosures and Financial Instrument Disclosures and Presentation

Effective January 1, 2008, the Company adopted three new accounting standards comprising CICA Handbook Sections 1535, *Capital Disclosures*; 3862, *Financial Instruments Disclosures*; and 3863, *Financial Instruments Presentation*. The adoption of these new standards required the disclosure of qualitative and quantitative information about the Company's capital and how it is managed, and an increased emphasis on disclosure about the risks associated with recognized and unrecognized financial instruments. The adoption of the new standard on presentation carried forward unchanged the presentation requirements from Section 3861, *Financial Instruments Disclosure and Presentation,* and therefore adoption of this new standard did not have any impact on the interim Consolidated Financial Statements.

Capital Disclosures

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, short-term and long-term debt, and cash and cash equivalents. The Company's capital structure as at September 30, 2008 and December 31, 2007 was as follows:

(Canadian dollars in millions)	**September 30, 2008**	**December 31, 2007**
Short-term notes payable	159	-
Long-term debt payable within one year	400	540
Less: Cash and cash equivalents	-	(12)
	559	552
Long-term debt	5,224	5,063
Preferred Shares	323	323
Common Shares	3,314	3,314
Retained Earnings	1,439	1,258
	5,076	4,895
Total Capital	10,859	10,510

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "short-term investments" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. Hydro One is in compliance with all of these covenants and limitations.

Financial Instrument Disclosures

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk and its foreign exchange risk is currently insignificant, although the Company could in future decide to issue foreign currency denominated debt. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution and transmission businesses is derived using a formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. The Company estimates that a 1% decrease in the forecast long-term Government of Canada bond yield used in the current OEB formula for determining the Company's rate of return on equity would reduce its Transmission Business' results of operations by approximately $20 million and its Distribution Business' results of operations by approximately $13 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at September 30, 2008, there were no significant balances of accounts receivable due from any single customer.

In the quarter, the Company's provision for bad debts remained relatively unchanged at $23 million. Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at September 30, 2008, approximately 5% of the Company's accounts receivable was aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques including, entering into transactions with highly rated counter-parties, limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy, entering into master agreements which enable net settlement and the contractual right of offset, and monitoring the financial condition of counterparties. Short-term investments held as at September 30, 2008, were consistent with the credit exposure limits specified under the Company's Credit Risk Policy. The Company's

credit risk for short-term investments and accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at September 30, 2008, the only derivative instrument held by Hydro One was a fixed-to-floating interest rate swap agreement to convert the 4.08% coupon maturing March 3, 2011 into variable rate debt. The exposure to credit risk from this derivative instrument as at September 30, 2008 was not significant.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, and the Company's Commercial Paper Program, under which it is 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 a $1 billion committed revolving credit facility with a syndicate of banks maturing in August 2010. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at September 30, 2008, accounts payable and accrued liabilities in the amount of $710 million and short-term notes payable in the amount of $159 million, are expected to be settled in cash at their carrying amounts within the next year. Short-term notes payable represent promissory notes with varying maturities not exceeding 365 days. Long-term debt maturing over the next twelve months is $400 million. Interest payments over the next twelve months on the Company's outstanding debt amount to $95 million.

As at September 30, 2008, Hydro One has issued long-term debt in the amount of $5,625 million and the Company is required to make interest payments in the amount of $5,169 million. Principal outstanding and interest payments are summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Interest Payments *(Canadian dollars in millions)*
1 – 5 years	1,900	1,386
6 – 10 years	1,050	1,016
Over 10 years	2,675	2,767
Total	5,625	5,169

Emerging Accounting Changes

Rate Regulated Operations

In August 2007, the Canadian Accounting Standards Board (AcSB) issued a decision, effective January 1, 2009, to withdraw the temporary exemption in CICA Handbook Section 1100, *Generally Accepted Accounting Principles,* which permits the recognition and measurement of assets and liabilities arising from rate regulation. Further, CICA Handbook Section 3465, *Income Taxes,* was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject these provisions. Consequently, the Company will be required to reflect on its Consolidated Balance Sheet, the effect of applying the liability method when accounting for payments in lieu of corporate income taxes and a corresponding regulatory asset. The Company is currently assessing the impact of the AcSB's decision on its Consolidated Balance Sheet.

Goodwill and Intangibles

In November 2007, the AcSB approved new CICA Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Sections 3062, *Goodwill and Other Intangible Assets*, and 3450, *Research and Development Costs*. The new section is applicable to Hydro One's interim and annual Consolidated Financial Statements for the 2009 fiscal year. The Company is currently evaluating the classification of certain assets currently classified as fixed assets in service to determine if they meet the definition of intangible assets.

3. ENVIRONMENTAL REGULATIONS

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of polychlorinated biphenyls (PCBs). These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The new regulations impose timelines for disposal of PCBs based on different types of equipment, in-use status and PCB contamination thresholds. Under the regulations, all PCBs in concentrations of 500 parts per million (ppm) or more, except pole-top transformers and their pole-top auxiliary electrical equipment and light ballasts, must be disposed of by the end of 2009. PCBs in concentrations of 50 ppm or more in pole-top transformers and their pole-top auxiliary electrical equipment, light ballasts and other electrical equipment must be disposed of by the end of 2025. In addition, liquids with 2 ppm or more that have been removed from equipment cannot be reused.

Management judges that the Company has very limited PCB-contaminated assets in excess of 500 ppm (priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets as quickly as operationally feasible. Assets to be disposed of primarily consist of pole and pad mount distribution transformers and light ballasts which require disposal by 2025. Contaminated distribution and transmission station equipment will generally be decontaminated by removing PCB-contaminated insulating oil and retrofilling with less than 2 ppm oil as the liquids are removed.

Consistent with its accounting policy for environmental costs, since 2001 Hydro One has recorded a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment. The Company's liability has been based on management's best estimate of the net present value of the future expenditures expected to be required to comply with existing PCB regulations.

Management's best estimate of the additional estimated future expenditures to comply with the final regulations is about $265 million. The increase in estimated future expenditures primarily relates to the inspection and testing of pole top distribution transformers, the removal and disposal of certain transmission and distribution station equipment and the decontamination and retrofilling of station equipment found to be in excess of regulatory thresholds. These expenditures will be incurred over the period from 2009 to 2025 with the majority of the spending occurring in the 2013 to 2025 period. As a result of the final regulations and the resulting increase in future expenditures, the Company has upwardly revised its liability in the third quarter by approximately $195 million.

As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a $195 million increase to the environmental regulatory asset has been recorded to reflect the probability of future recovery of these PCB expenditures from customers.

In determining the amounts to be recorded as environmental liabilities, the Company has estimated the current cost of completing mitigation work and has made assumptions as to when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. These future expenditures are discounted using factors ranging from 5.14% to 6.25% depending on the year the obligations were first recorded. All factors used in estimating our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. In addition, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

4. PENSION ASSET TRANSFER

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP, including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi LP. On March 10, 2008, the Company was granted consent from the Financial Services Commission of Ontario to transfer pension assets and related pension liabilities for affected employees from the Hydro One Pension Plan to the Inergi LP Pension Plan. Under the

agreement, the Company recognized a settlement of $21 million in its results of operations for the first quarter, inclusive of a related interest credit of $6 million. The pension asset transfer took place in the second quarter.

5. DIVIDENDS

During the three months ended September 30, 2008, preferred dividends in the amount of $4 million (2007 - $4 million) and common dividends in the amount of $68 million (2007 - $68 million) were declared. During the nine months ended September 30, 2008, preferred dividends in the amount of $13 million (2007 - $13 million) and common dividends in the amount of $173 million (2007 - $239 million) were declared.

6. LONG-TERM DEBT

In January 2008, the Company entered into a forward starting interest rate swap agreement to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $60 million and was used to lock in the interest rate of a forecasted debt issuance which took place on March 3, 2008. The transaction was accounted for as a cash flow hedge of a forecasted transaction.

On March 3, 2008, Hydro One issued additional notes under the Company's Medium-Term Note Program. The new issue was comprised of medium term notes with a principal amount of $250 million having a 3-year term with a coupon rate of 4.08%. The notes are due March 3, 2011. On the same date the Company made an additional offering of 5.18% medium-term notes that originally settled October 18, 2007. The issue was comprised of medium-term notes with a principal amount of $300 million having a 9.6 year term with a coupon rate of 5.18%. The notes are due October 18, 2017. In relation to this debt issuance, on March 3, 2008, the Company terminated the three forward starting interest rate swaps entered into in the last quarter of 2007 and the first quarter of 2008 that had a total notional principal amount of $200 million. The transactions had been accounted for as cash flow hedges of a forecasted debt issue for the purpose of fixing the interest rate for the debt issuance. The net loss realized on terminating the swaps was $1.2 million which has been recorded in Other Comprehensive Income and will be amortized to financing charges over the term of the related debt.

In the second quarter, the Company entered into a $250 million notional principal amount fixed-to-floating interest rate swap to convert Hydro One's 4.08% coupon note maturing March 3, 2011 into variable rate debt. This transaction was accounted for as a fair value hedge, with the consequence that the related debt is carried at fair value.

7. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2008**	**2007**	**2008**	**2007**
Pension				
Net periodic benefit cost	10	26	30	76
Pension fund contribution	25	25	75	76
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	10	29	30
Charged to results of operations	15	15	46	46
Employee Future Benefits Other than Pension				
Net periodic benefit cost	24	27	69	80
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	9	10	27	31
Charged to results of operations	15	17	42	49

8. 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
- An "other" segment primarily consisting of a telecommunications business.

The designation of segments has been 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**
2008				
Segment profit				
Revenues	315	797	14	1,126
Purchased power	-	526	-	526
Operation, maintenance and administration	104	139	13	256
Depreciation and amortization	64	71	2	137
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	147	61	(1)	207
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				134
Capital expenditures	179	139	3	321
2007				
Segment profit				
Revenues	307	813	8	1,128
Purchased power	-	533	-	533
Operation, maintenance and administration	117	137	9	263
Depreciation and amortization	56	71	1	128
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	134	72	(2)	204
Financing charges				76
Income before provision for payments in lieu of corporate income taxes				128
Capital expenditures	144	126	5	275

Nine months ended September 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2008				
Segment profit				
Revenues	912	2,454	37	3,403
Purchased power	-	1,605	-	1,605
Operation, maintenance and administration	306	392	34	732
Depreciation and amortization	185	209	5	399
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	421	248	(2)	667
Financing charges				217
Income before provision for payments in lieu of corporate income taxes				450
Capital expenditures	439	387	9	835

Nine months ended September 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
Revenues	949	2,555	22	3,526
Purchased power	-	1,696	-	1,696
Operation, maintenance and administration	323	410	23	756
Depreciation and amortization	176	202	4	382
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	450	247	(5)	692
Financing charges				223
Income before provision for payments in lieu of corporate income taxes				469
Capital expenditures	394	355	16	765

(Canadian dollars in millions)	**September 30, 2008**	**December 31, 2007**
Total assets		
Transmission	7,649	7,273
Distribution	5,643	5,411
Other	115	106
	13,407	12,790

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

9. SUBSEQUENT EVENTS

On November 10, 2008, Hydro One issued notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $400 million having a 5-year term with a coupon rate of 5.00%. The notes are due on November 12, 2013.

10. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the September 30, 2008 unaudited interim Consolidated Financial Statements.