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 six months ended June 30, 2009 to the three and six months ended June 30, 2008.

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	**2009**	**2008**	**$ Change**	**% Change**	**2009**	**2008**	**$ Change**	**% Change**
Transmission	271	293	(22)	(8)	573	597	(24)	(4)
Distribution	803	749	54	7	1,789	1,657	132	8
Other	16	13	3	23	31	23	8	35
	1,090	1,055	35	3	2,393	2,277	116	5
Average Ontario 60-minute peak demand *(MW)*[1]	19,615	20,786	(1,171)	(6)	20,901	21,531	(630)	(3)
Distribution - units distributed to customers *(TWh)*[1]	6.4	6.7	(0.3)	(4)	14.8	15.2	(0.4)	(3)

[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. Demand 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 lower by $22 million, or 8% in the second quarter, and by $24 million, or 4% in the first six months compared to the same periods last year. The average monthly peak demand was lower for both the second quarter and the first six months resulting in a reduction of transmission revenues of $10 million and $9 million, respectively.

Export service revenue attributable to the transmission of electricity to other jurisdictions was lower by $7 million in both the quarterly and year-to-date periods as a result of volume reductions combined with the impact of a May 28, 2009 Ontario Energy Board (OEB) decision. Consistent with this decision, actual export service credit amounts in excess of forecast levels are to be recorded as a regulatory liability.

Transmission revenues for the second quarter and in the first six months were affected by the OEB August 28, 2008 rate decision to approve our application to adjust Uniform Transmission Rates effective January 1, 2009, to return to the 2008 OEB-approved revenue requirement following the repayment of the earnings sharing mechanism (ESM) and revenue difference deferral account (RDDA) to customers. Both the ESM and the RDDA were regulatory liabilities that were set up to capture the excess amounts collected from customers as a result of the August 16, 2007 OEB rate decision, to be returned to customers over a 14-month period from November 1, 2007 to December 31, 2008. As a result, we experienced a decrease of $25 million in the quarter and $51 million in the year to date periods since revenue was recognized in 2008 upon repayment of the ESM and RDDA. This impact was partially offset by the increase in transmission rates of $21 million in the second quarter and $45 million in the first six months of the year.

We also experienced lower other revenues of approximately $1 million in the quarter and $2 million on a year-to-date basis.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution rate. 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 by $54 million, or 7%, in the second quarter, and by $132 million, or 8%, in the first six months compared to the same periods last year. This change related primarily to the recovery of higher purchased power costs of $35 million in the second quarter and $105 million in the first six months, as described below under "Purchased Power." OEB approved increases in the distribution tariff rates for our subsidiary, Hydro One Networks Inc. (Hydro One Networks), on December 18, 2008, in respect of our cost of service application, and on May 13, 2009, in respect of our rate application under the Third Generation Incentive Rate Mechanism (IRM) resulted in higher distribution revenues of $20 million during the second quarter and $32 million in the first six months compared to the same periods last year. These tariff rate increases, which support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, were implemented on February 1, 2009, and June 1, 2009 respectively. We also experienced higher other revenues of approximately $6 million in the quarter and $4 million in the year-to-date period.

Distribution revenue increases were partially offset by lower energy consumption, resulting primarily from the milder weather this year which reduced our distribution revenues by $7 million in the quarter and $4 million in the first six months. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective March 31, 2008, which resulted in lower revenues of $5 million on a year-to-date basis.

Other

Higher revenues in our Telecom Business derived from a newly constructed dedicated optical network providing secure, high capacity connectivity across numerous health care locations in Ontario increased revenues by $3 million, or 23%, in the quarter and by $8 million, or 35%, in the year-to-date period.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise 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 are 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.

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2007	1,000	750	5.0	5.9
May 1, 2008	600	750	5.0	5.9
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6

Purchased power costs increased in 2009 by $35 million, or 7%, to $518 million in the second quarter and increased by $105 million, or 10% to $1,184 in the first six months compared to the same periods last year. The increase in our purchased power costs were primarily due to changes in the OEB's RPP rate for residential and other eligible customers of $37 million in the quarter and $93 million in the year-to-date period, the impact of higher charges levied by the IESO of $14 million in the quarter and $23 million in the first six months, reflecting both higher transmission charges due to the OEB's August 28, 2008 transmission rate decision and increased wholesale market service charges, and higher purchased power costs for customers who are not eligible for the RPP of $5 million in the year-to-date period. These increases were partially offset by lower demand for electricity of $16 million for both the quarter and year-to-date periods.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are 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 June 30				**Six months ended June 30**			
(Canadian dollars in millions)	**2009**	**2008**	**$ Change**	**% Change**	**2009**	**2008**	**$ Change**	**% Change**
Transmission	120	105	15	14	223	202	21	10
Distribution	147	138	9	7	274	253	21	8
Other	14	12	2	17	27	21	6	29
	281	255	26	10	524	476	48	10

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $15 million, or 14%, in the quarter and by $21 million, or 10%, on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were higher by $11 million in the quarter and $7 million on a year-to-date basis, compared to the same periods last year. For the quarter, we experienced increased expenditures associated with our line maintenance, forestry and station maintenance programs as well as increased expenditures relating to asset security and third party ancillary services. For the year-to-date period, expenditures associated within these programs were generally consistent with the prior year. In addition, we experienced increases of $4 million and $14 million in our expenditures incurred to support the transmission system in the second quarter and first six months, respectively. The year-to-date increase was mainly attributable to the impact of a one-time settlement credit in 2008 associated with the transfer of assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services Commission of Ontario (FSCO).

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $9 million, or 7%, in the quarter and by $21 million, or 8%, on a year-to-date basis, compared to the same periods last year. Our work program expenditures were higher by $8 million in both the quarter and the first six months, primarily due to unplanned line maintenance work and customer care expenditures, partially offset by lower planned line maintenance work. Our expenditures in support of our distribution business remained relatively unchanged by $1 million in the quarter but were higher by $13 million on a year-to-date basis. The year-to-date impact was mainly attributable to a one-time settlement credit in 2008 associated with the transfer of assets to the Inergi pension plan.

Depreciation and Amortization

Depreciation and amortization expense decreased by $3 million, or 2%, to $129 million in the second quarter and by $9 million, or 3%, to $253 million in the first six months compared to the same periods last year. These reductions were primarily attributable to reduced amortization expenses from regulatory accounts that have been fully recovered. The impact of these reductions was partially offset by higher depreciation expense from new assets placed in service.

Financing Charges

Financing charges decreased by $1 million, or 1%, to $74 million in the second quarter and increased by $2 million, or 1%, to $146 million for the year-to-date compared to the same periods last year. Financing charges decreased in both the quarter and for the year-to-date before consideration of the impact of a one-time $6 million interest credit in the first quarter of 2008 related to the Inergi pension asset transfer. The decreases primarily resulted from higher interest capitalization due to higher construction in progress levels. The impact of the reductions was partially offset by higher net interest expense, reflecting higher average levels of debt, higher average long-term borrowing rates, and by lower interest income reflecting lower average investments and lower short-term interest rates.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $6 million, or 50%, to $6 million in the second quarter and decreased by $34 million, or 56%, to $27 million on a year-to-date basis, compared to the same periods last year. The changes primarily reflect the impact of increased temporary differences relating to higher capital cost allowance deductions being available on our information system and smart meter investments combined with temporary differences associated with certain regulatory accounts partially offset by an increase to the provision for future payments in lieu of corporate income taxes.

Net Income

Net income was $82 million in the second quarter, lower by $16 million, or 16%, compared with the second quarter of 2008, and $259 million year-to-date, representing a $4 million, or 2%, increase over the prior year. In the quarterly and year-to-date periods, net income was impacted by higher operation, maintenance and administration expenditures related to work programs necessary to sustain our transmission and distribution systems. On a year-to-date basis, operation, maintenance and administration expenditures were further impacted, in comparison to the prior year, by a one-time settlement credit in the first quarter of 2008 associated with the transfer of pension assets to the Inergi pension plan. The impact to net income of increased operation, maintenance and administration requirements on a year-to-date basis was more than offset by higher distribution tariff revenues associated with the December 18, 2008 and May 13, 2009 Ontario Energy Board (OEB) rate decisions in support of necessary work programs, combined with a reduction in our payments in lieu of corporate income taxes, primarily resulting from higher capital cost allowance deductions being available on our information system and smart meter investments.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2007 through June 30, 2009. 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)	**2009**	**2008**					**2007**	
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31[3]**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30[2]**
Total revenue[1]	1,090	1,303	1,194	1,126	1,055	1,222	1,129	1,128
Net income[1]	82	177	131	112	98	157	90	67
Net income to common shareholder[1]	77	173	126	108	93	153	85	63

[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 Hydro One Networks' 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 reduction 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.

[3] As a result of the OEB's December 18, 2008 decision on Hydro One Network's distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008, reflecting growth in the work program requirements and investment in capital infrastructure.

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 June 30**		**Six months ended June 30**	
(Canadian dollars in millions)	**2009**	**2008**	**2009**	**2008**
Operating activities	194	255	379	484
Financing activities				
Long-term debt issued	-	-	600	550
Long-term debt retired	-	(540)	(400)	(540)
Short-term notes payable	75	125	225	125
Dividends paid	(27)	(73)	(135)	(114)
Investing activities				
Capital expenditures	(383)	(303)	(719)	(514)
Other financing and investing activities	1	3	14	14
Net change in cash and cash equivalents	(140)	(533)	(36)	5

Operating Activities

Net cash from operating activities decreased by $61 million, to $194 million in the second quarter, and decreased by $105 million to $379 million in the first six months compared to 2008 results. The reduction is a result of higher working capital requirements in the quarter and year-to-date periods, compared to the same periods last year, primarily related to increases in our work program requirements and to amounts recorded in certain regulatory accounts such as the regulatory liability refund account. These reductions were partially offset by the repayment to customers in 2008 of amounts recorded in the RDDA following the 2007 transmission rate decision as well as by higher net income.

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 June 30, 2009, we had $225 million of short-term notes 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 June 30, 2009, we had $6,325 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On July 27, 2009, we filed a base shelf prospectus to renew our Medium-Term Note Program for another 25 months. The maximum authorised principal amount of medium-term notes issuable under this program is $3 billion, all of which currently remains available until August 2011.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	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.

During the second quarter of 2009, we did not issue any long-term debt and we had no long-term debt maturities. We also did not issue any long-term debt during the second quarter of 2008 but we had $540 million in debt maturities. In the second quarter of 2009, the amount of short term notes outstanding increased by $100 million year-over-year while in the second quarter of 2008, short term notes outstanding increased by $50 million year-over-year.

In the second quarter of 2009, we paid dividends to the Province of Ontario (the Province) in the amount of $27 million, consisting of $22 million in common dividends and $5 million in preferred dividends. In the comparative period for 2008, we paid common dividends of $68 million and preferred dividends of $5 million.

In the first six months of 2009, we paid dividends to the Province in the amount of $135 million, consisting of $126 million in common dividends and $9 million in preferred dividends. In the comparative period last year, we paid common dividends of $105 million and preferred dividends of $9 million.

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, shareholder expectations and maintenance of the deemed regulatory capital structure. 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 June 30				Six months ended June 30			
(Canadian dollars in millions)	**2009**	**2008**	**$ Change**	**% Change**	**2009**	**2008**	**$ Change**	**% Change**
Transmission	218	153	65	42	405	260	145	56
Distribution	163	146	17	12	311	248	63	25
Other	2	4	(2)	(50)	3	6	(3)	(50)
	383	303	80	26	719	514	205	40

Transmission

Transmission capital expenditures increased by $65 million, or 42%, to $218 million in the second quarter, and increased by $145 million, or 56%, to $405 million in the first six months, compared to the same periods in 2008.

Expenditures to expand and reinforce our transmission system were $116 million in the quarter and $203 million for the first six months of the year, representing increases of $52 million and $92 million over the respective comparable periods. These increases were primarily attributable to a number of significant inter-area network upgrade projects to increase generation as well as an increase in expenditures on local area supply projects to address growing loads. These increases were partially offset by a number of load and generation projects that were completed or that were nearing completion last year, such as the Pleasant and Lambton transformer station projects.

Inter-area network upgrades with significant expenditures include the Bruce to Milton Transmission Reinforcement Project to connect redeveloped nuclear and new wind generation sources in the Huron-Grey-Bruce area, the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the Greater Toronto Area (GTA) and the South Western Ontario Capacitor Banks Project, which will expand transmission capacity in the Bruce area to enable the delivery of additional generation from the Bruce “A” nuclear plant and committed wind generation. The impacts of these increases were partially offset by the substantial completion in the first part of 2008 of our construction phase of an interconnection project with Québec that will increase access to emission-free hydroelectric power.

Local area supply projects with significant expenditures include our GTA West Transmission Reinforcement Project, which will increase capacity in the western GTA to ensure supply reliability in the area, 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 and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, which will increase transmission capacity in the Western Brampton area to allow for future load growth. The final completion of our Niagara Reinforcement Project 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.

Expenditures to sustain our existing transmission system were $72 million in the quarter and $136 million on a year-to-date basis, representing increases of $6 million and $31 million respectively compared to the same periods last year. These increases primarily relate to the refurbishment and replacement of end-of-life equipment associated with various station projects and to the timing of expenditures within our Spare Transformer Purchase Program. We have continued our investment in our Claireville Transformer Station Project to improve reliability and to meet growing demand, which is expected to be completed this year.

Our other transmission capital expenditures were $30 million in the quarter and $66 million for the first six months, representing respective increases of $7 million and $22 over the comparative periods. These increases were mainly attributable to higher expenditures associated with information security enhancements. We also experienced significant information technology project expenditures were also made related to an entity-wide information system replacement and improvement project to replace end-of-life systems and improve productivity. The second phase of this project will be placed in service in August.

Distribution

Distribution capital expenditures increased by $17 million, or 12%, to $163 million in the second quarter and by $63 million, or 25%, to $311 million for the first six months, compared to the same periods in 2008.

Capital expenditures to expand and reinforce our distribution network were $86 million in the quarter and $171 million for the first six months of the year, representing increases of $3 million and $47 million over the comparable periods. These increases primarily reflect ongoing investments in our Smart Meter Program. During the quarter, we installed approximately 130,000 smart meters, bringing our cumulative program total to about 1,025,000 meters.

Expenditures to sustain our distribution system of $63 million in the quarter and $109 million year-to-date, increased by $13 million and $14 million, respectively, compared to the respective periods last year. These increases were primarily the result of increased engineering and construction work to upgrade or replace wholesale meters, increased investments to replace components within our distribution stations, higher expenditures on our unplanned line work programs and higher costs related to line relocation work. Our other distribution capital expenditures were $14 million in the quarter and $31 million for the first six months, representing respective increases of $1 million and $2 million from the comparative periods. The majority of these expenditures reflect our investment in our entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures for 2009 are budgeted at $1.6 billion. The 2009 capital budgets for our transmission and distribution businesses are approximately $950 million and $650 million, respectively. Capital expenditures are expected to exceed $1.7 billion in 2010 and $1.5 billion in 2011, primarily reflecting investments to expand, refurbish or replace transmission and distribution infrastructure, consistent with government policy, Ontario Power Authority (OPA) planning information including the Integrated Power System Plan (IPSP), local area supply requirements and the preventive and corrective maintenance needs to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest, as well as enable renewable generation connections. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007 and which will be completed by the end of 2010. The replacement of critical information technology systems is also underway. Capital expenditures of our other business segment are budgeted at about $7 million in 2009, reflecting sustainment of the fibre optic network.

The *Green Energy and Green Economy Act 2009* (the *Act*) which received Royal Assent on May 14, 2009 will lead to additional investments in the electricity system to facilitate renewable generation, and higher investments through advanced technologies to increase functionality and reliability of the electricity grid. Investments in advanced technologies will build on the investment already planned for, and underway, in smart meters and the associated communications and data processing capacity. The determination of the precise nature and volume of incremental investments to facilitate the connection of renewable generation, to enable a smart grid and to comply with other parts of the *Act* will be an ongoing part of our investment planning process.

In July 2009, as part of our 2010 and 2011 distribution rate applications for our subsidiary Hydro One Networks, we filed our Distribution Green Energy Plan. This was filed in accordance with the *Act* which directed the OEB to require transmitters and distributors to file plans that would lead to expansion of their systems to facilitate renewable energy. Our application is based on the assumption that a substantial portion of the expansion and enabling investments for renewable generation contained in our plan will be recovered through an external funding mechanism. This reflects the fact that our service territory covers the majority of regions in the Province with high potential for renewable generation development, and that connecting renewable energy generation benefits all load customers in the Province.

Additional investments in support of the *Act* for our distribution and transmission businesses are not expected to be material for 2009. For 2010 and 2011, the additional investments could be significant, in the range of $1 billion, although there is significant uncertainty over the extent of expenditures to be incurred by our company. Additional investments will depend, to some extent, on which investments are determined by the government and the OEB to be appropriate system investments to be borne through our rate base, and which are assigned to generators.

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.

June 30, 2009 (Canadian dollars in millions)	**Total**	**2009**[1]	**2010/2011**	**2012/2013**	**After 2013**
Contractual Obligations *(due by year)*					
Short-term notes payable	225	225	-	-	-
Long-term debt – principal repayments	6,325	-	1,100	1,200	4,025
Long-term debt – interest payments	5,598	181	668	564	4,185
Inergi outsourcing agreement[2]	253	49	188	16	-
Operating lease commitments	62	4	13	13	32
Total Contractual Obligations	12,463	459	1,969	1,793	8,242
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	1,000	-	1,000	-	-
Letters of credit[4]	121	110	11	-	-
Guarantees[4]	325	325	-	-	-
Pension[5]	57	49	8	-	-
Total Other Commercial Commitments	1,503	484	1,019	-	-

[1] The amounts disclosed represent the balances due over the period July 1, 2009 to December 31, 2009.

[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. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

[3] As a backstop to our commercial paper program, we have a $1,000 million revolving standby credit facility with a syndicate of banks which matures in August 2010.

[4] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. The other $14 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 guarantees of up to a maximum of $325 million and on behalf of a distributor using a guarantee of up to a maximum of $335 thousand. 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. In January 2009, we issued an additional letter of credit in the amount of $10 million relating to an agreement to purchase goods.

[5] Contributions to the pension fund are made one month in arrears. Contributions for 2009 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2009 will be about $105 million. Contributions beyond 2009 will be based on an actuarial valuation effective no later than 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.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

During the first six months of 2009, the deferred pension asset reported on our Balance Sheet decreased by $9 million to $432 million. We have contributed $56 million into our pension plan in 2009 and incurred $65 million in net periodic pension benefit costs. Our annual funding contributions for 2009 will be approximately $105 million.

Performance of the pension plan improved in the second quarter as negative returns experienced earlier in the year were more than offset by gains in the second quarter resulting in modest positive returns on a year-to-date basis. However, consistent with other pension plans, our pension plan could be negatively impacted in 2009 as a result of the current economic uncertainty and financial market volatility. Should the plan incur negative returns in 2009, or if the discount rate falls sufficiently by the end of the year, the deficit position at that time could lead to a large increase in our contribution requirements beyond 2009. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. As a result, the fund was negatively impacted in 2008 and into the first quarter of 2009 but partially recovered in the second quarter of 2009, consistent with the returns experienced in financial markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

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 for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. In anticipation of this decision, we commenced our IFRS conversion project in 2007. The project was established with a formal project governance structure that includes a steering committee consisting of senior levels of management from finance, information technology, treasury and our operations organizations. 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.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We have completed the diagnostic phase involving a high level review of the major differences between current Canadian GAAP and IFRS in all subject areas. In this phase, we determined that the areas of accounting difference with the highest potential to significantly 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 now engaged in the design and planning, solution development and implementation phases of our project. Issue-specific teams are focusing on documenting issues, generating options and making recommendations. We are currently in the implementation phase for the significant areas of accounting differences. In these areas, our teams are establishing key milestones, developing recommendations, analyzing financial system impacts, developing financial reports and carrying on ongoing discussions with our external auditors. We are evaluating the impacts of IFRS on all of our business activities including our subsidiaries.

The impacts of IFRS and potential solutions on disclosure controls and internal controls over financial reporting are also being examined. Analysis of other business impacts, such as impacts on debt covenants and performance measures, also continues. We have established a staff communications plan and have completed significant staff training sessions, with additional training to come.

In December 2008, the International Accounting Standards Board (IASB) added a project on rate regulated activities to its agenda. On July 23, 2009, the IASB released an exposure draft on rate-regulated activities with an expectation that a final standard will be released by the end of June 2010 with an effective date of January 2011. The exposure draft allows for the continued recognition of regulatory assets and liabilities on the Balance Sheet. Such assets and liabilities are proposed to be carried at the net present value of the expected future cash flows. It is proposed that these expected cash flows will be derived by weighting potential scenarios for respective probability. In addition, the exposure draft makes an exception to the requirements of other standards by allowing continued capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the costs' inclusion in rate base.

At a meeting held in November 2008, the Canadian Public Sector Accounting Board's (PSAB) agreed to reevaluate an earlier conclusion that government organizations following commercial practices, such as our company, continue to issue financial statements in accordance with GAAP for profit-oriented enterprises. For such enterprises that are also publicly accountable, this would become IFRS after January 1, 2011. As a result, on February 24, 2009, the PSAB issued an Invitation to Comment that supported the opinion that affected government business enterprises, such as our company, should adopt IFRS. In July 2009, the PSAB issued an exposure draft that proposes that all government business enterprises would adhere to IFRS as publicly accountable enterprises and would follow the same transitional provisions for fiscal periods beginning January 1, 2011. On July 23, 2009, the Canadian Securities Administrators' staff confirmed that all registrants will be required to use IFRS commencing January 1, 2011, with the exception of members of self-regulating organizations.

In May 2008, the OEB began a process to determine the nature of any changes that should be made in regulatory reporting requirements in response to IFRS. The OEB held several consultation meetings and a formal stakeholder conference on this subject in May 2009. We participated fully in each of the OEB initiatives to date. On July 28, 2009, the OEB released its recommendations on how regulatory reporting requirements should change in response to IFRS. The OEB plans to initiate a second phase of the consultation to amend certain regulatory instruments. We are currently assessing the impact of the OEB's report on our IFRS conversion project.

We continue to assess the potential impacts of these various initiatives on our future financial position and results of operations.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

We are continuing to transition our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. 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.

The first phase of the transition including the supply chain, asset and work management modules within SAP was implemented in 2008. A portion of the Financial Accounting and Control modules were also implemented to facilitate financial reporting. The second phase of the transition was implemented in early August 2009 and involved the replacement of the remaining finance, human resources and pay modules. The implementations included new controls over Internal Controls over Financial Reporting (ICFR) and replaced controls in the previous information technology system.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended June 30, 2009, together with other financial information included in our quarterly securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company. We also certify that ICFR has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

Status of Rate Applications

Hydro One Networks Inc.

On May 13, 2009, the OEB released its decision regarding the 2009 distribution rate application. The OEB approved our submission on the basis of the OEB's third generation IRM policies. The revised rates, including an amount of $1.65 per month per metered customer for smart meters, were approved effective May 1, 2009, with an implementation date of June 1, 2009.

On May 28, 2009, the OEB issued its decision in respect of our 2009 and 2010 transmission rate application. The decision, which was effective July 1, 2009, resulted in an approved revenue requirement of $1,180 million and $1,240 million for 2009 and 2010, respectively. This will result in essentially no change in an average customers' total bill in 2009 and an increase of less than 0.5% in 2010.

On July 13, 2009, we filed our cost of service application with the OEB for 2010 and 2011 for our Distribution Business. To achieve the necessary funding in support of required infrastructure, the application seeks OEB approval for revenue requirements of approximately $1,181 million and $1,294 million based on a return on equity of 8.11% and 9.09% for 2010 and 2011, respectively. This translates into an average annual increase on total customer bills of approximately 3% in 2010 and 4% in 2011. The application also included a distribution investment plan to enable renewable generation consistent with the *Green Energy and Green Economy Act*, for the period 2010 to 2014.

Green Energy and Green Economy Act, 2009

On May 14, 2009, the *Green Energy and Green Economy Act, 2009* was passed in the Ontario Legislature.

OEB Consultations

Distribution System Planning

On June 16, 2009, the OEB released initial guidelines relating to accounting, funding and planning for distribution system development to accommodate renewable generation. and to develop a smart grid. The guidelines will enable distributors to expedite investments to be made in accordance with the *Green Energy and Green Economy Act, 2009*. The guidelines allow for the establishment of new deferral accounts for costs related to projects that promote renewable generation. They also introduce a mechanism that provides advance funding for qualifying expenditures to accommodate renewable generation or to develop a smart grid, as well as initial guidance regarding the preparation of plans to accommodate renewable generation and/or a smart grid. The OEB is planning to hold a consultation process to further develop the distribution system plan filing guidelines.

Regulatory Treatment of Infrastructure Investments

On June 10, 2009, the OEB issued a staff discussion paper initiating a consultation with stakeholders on more innovative approaches to cost recovery for electricity infrastructure projects. The paper sets out a range of mechanisms for the regulatory treatment of infrastructure investment that could be used to support the setting of rates. These mechanisms include recovery of development costs, recovery of costs as incurred, and the potential incentive of a higher project specific return on equity. The OEB has invited written comments and encouraged participants to put forward alternative proposals for consideration. Hydro One submitted comments on July 7, 2009.

Proposed Amendment to the Distribution System Code (DSC)

On June 5, 2009, the OEB issued a notice of proposal to amend the DSC to promote the connection of renewable resources. The proposed amendments would reduce the generator's costs of distribution system investments by making the distributor responsible for costs related to renewable enabling improvements and by bearing only some of the costs of system expansions. Our subsidiary, Hydro One Networks, submitted comments on June 30, 2009.

Status of Leave-to-Construct Application

On August 5, 2009, the OEB issued a decision approving our leave-to-construct application for our Lower Mattagami Transmission Reinforcement Project, to build a second transmission circuit as an addition to the existing single circuit transmission line in the Lower Mattagami area. The addition is required to improve the reliability and quality of electricity service in this region and increases the capacity of the existing circuit to add new generation to the system.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions) (except as otherwise noted)	**2009**	**2008**	**2009**	**2008**
Net income	82	98	259	255
Net cash from operating activities	194	255	379	484
Capital expenditures	383	303	719	514
Basic and fully diluted earnings per common share *(Canadian dollars)*	781	937	2,505	2,461
Earnings coverage ratio[1]			2.42	2.59
Net asset coverage on long-term debt[2]			1.83	1.84
Total debt to capitalization[3]			55%	54%

[1]The earnings coverage ratio has been presented for the twelve months ended June 30, 2009 and June 30, 2008, 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 June 30, 2009 and December 31, 2008 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 June 30, 2009 and December 31, 2008 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 amendments to codes, the impact of new regulatory guidelines and impacts of decisions from the OEB and other governing bodies; 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; expectations regarding the impact of the *Green Energy and Green Economy Act, 2009* on our company, the expected additional investments arising therefrom and the expected recovery of a substantial portion of the expenditures through an external funding mechanism; statements regarding contractual obligations and other commercial commitments; statements regarding future pension contributions; and statements about IFRS and our conversion to IFRS. 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:

- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the 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 impact of the *Green Energy and Green Economy Act, 2009* on our company, the additional investments arising therefrom and decisions regarding the recovery of the related capital expenditures; 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 2008 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 August 12, 2009. 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 June 30		Six months ended June 30	
(Canadian dollars in millions)	**2009**	**2008**	**2009**	**2008**
Revenues				
Transmission	271	293	573	597
Distribution	803	749	1,789	1,657
Other	16	13	31	23
	1,090	1,055	2,393	2,277
Costs				
Purchased power	518	483	1,184	1,079
Operation, maintenance and administration *(Note 5)*	281	255	524	476
Depreciation and amortization	129	132	253	262
	928	870	1,961	1,817
Income before financing charges and provision for payments in lieu of corporate income taxes	162	185	432	460
Financing charges *(Note 5)*	74	75	146	144
Income before provision for payments in lieu of corporate income taxes	88	110	286	316
Provision for payments in lieu of corporate income taxes	6	12	27	61
Net income	82	98	259	255
Other comprehensive loss	-	-	-	(1)
Comprehensive income	82	98	259	254
Basic and fully diluted earnings per common share *(Canadian dollars)*	781	937	2,505	2,461

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2009**	**2008**	**2009**	**2008**
Retained earnings, beginning of period	1,578	1,374	1,497	1,258
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	-	-	12	-
Net income	82	98	259	255
Dividends *(Note 3)*	(27)	(73)	(135)	(114)
Retained earnings, end of period	1,633	1,399	1,633	1,399

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2009**	**2008**	**2009**	**2008**
Accumulated other comprehensive income, beginning of period	(10)	(10)	(10)	(9)
Other comprehensive loss	-	-	-	(1)
Accumulated other comprehensive income, end of period	(10)	(10)	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**June 30, 2009**	**December 31, 2008**
Assets		
Current assets:		
Cash and cash equivalents	-	16
Short-term investments	9	-
Accounts receivable (net of allowance for doubtful accounts)	768	754
Regulatory assets	66	64
Materials and supplies	22	19
Other *(Note 2)*	36	15
	901	868
Fixed assets:		
Fixed assets in service	17,667	17,334
Less: accumulated depreciation	(6,601)	(6,418)
	11,066	10,916
Construction in progress	1,212	912
Future use land, components and spares	130	132
	12,408	11,960
Long-term assets:		
Deferred pension asset	432	441
Regulatory assets *(Note 2)*	898	291
Goodwill	133	133
Intangible assets (net of accumulated amortization) *(Note 2)*	199	162
Future income tax assets *(Note 2)*	14	-
Other	17	21
	1,693	1,048
Total assets	15,002	13,876

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**June 30, 2009**	**December 31, 2008**
Liabilities		
Current liabilities:		
Bank indebtedness	29	-
Accounts payable and accrued charges *(Note 2)*	698	791
Regulatory liabilities *(Note 2)*	88	43
Accrued interest	65	64
Short-term notes payable	225	-
Long-term debt payable within one year *(Note 4)*	400	400
	1,505	1,298
Long-term debt *(Note 4)*	5,937	5,733
Other long-term liabilities:		
Employee future benefits other than pension	929	908
Regulatory liabilities *(Note 2)*	528	564
Future income tax liabilities *(Note 2)*	590	-
Environmental liabilities	239	237
Long-term accounts payable and other liabilities	14	12
	2,300	1,721
Total liabilities	9,742	8,752
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 *(Note 2)*	1,633	1,497
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	5,260	5,124
Total liabilities and shareholder's equity	15,002	13,876

See accompanying notes to Consolidated Financial Statements.

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

(Canadian dollars in millions)	**Three months ended June 30** **2009**	**2008**	**Six months ended June 30** **2009**	**2008**
Operating activities				
Net income	82	98	259	255
Environmental expenditures	(2)	(3)	(3)	(5)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	116	118	231	241
Revenue difference deferral account	-	(18)	-	(38)
Regulatory liability refund account	(5)	10	(10)	32
Other regulatory asset and liability accounts	(14)	(1)	(24)	3
Future income taxes	2	-	5	-
Amortization of debt discount	-	1	-	2
	179	205	458	490
Changes in non-cash balances related to operations	15	50	(79)	(6)
Net cash from operating activities	194	255	379	484
Financing activities				
Long-term debt issued	-	-	600	550
Long-term debt retired	-	(540)	(400)	(540)
Short-term notes payable	75	125	225	125
Dividends paid	(27)	(73)	(135)	(114)
Other	1	1	7	6
Net cash from (used in) financing activities	49	(487)	297	27
Investing activities				
Capital expenditures				
Fixed assets	(355)	(274)	(666)	(467)
Intangible assets	(28)	(29)	(53)	(47)
	(383)	(303)	(719)	(514)
Other assets	-	2	7	8
Net cash used in investing activities	(383)	(301)	(712)	(506)
Net change in cash and cash equivalents	(140)	(533)	(36)	5
Cash and cash equivalents, beginning of period *(Note6)*	120	526	16	(12)
Cash and cash equivalents, end of period	(20)	(7)	(20)	(7)

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, 2008 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 – Goodwill and Intangible Assets

Effective January 1, 2009, the Company retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3064, *Goodwill and Intangible Assets* which replaced CICA Handbook Sections 3062, *Goodwill and Other Intangible Assets*, and CICA Handbook Section 3450, *Research and Development Costs*. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

Upon adoption of the new accounting standard, on January 1, 2009, the Company reclassified $159 million in computer applications software previously classified as fixed assets to intangible assets. In addition, the Company also reclassified other assets with a net book value of $3 million that were previously classified as long-term other assets to intangible assets.

Change in Accounting Policy – Income Taxes

Effective January 1, 2009, the Company adopted amendments to the CICA Handbook Section 3465 - *Income Taxes* and CICA Handbook Section 1100 – *Generally Accepted Accounting Standards.* These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the adoption of these amended sections requires the recognition of future income tax assets and liabilities, and correspondingly the recognition of regulatory liabilities and assets. The temporary differences primarily relate to capital cost allowance in excess of deprecation and employee future benefits other than pension.

As a result of adopting these amended standards, on January 1, 2009, the Company recognized current future income tax assets of $20 million, long-term future income tax assets of $12 million and long-term future income tax liabilities of $503 million. The current future income tax asset is included with other assets on the Balance Sheet. The Company also recognized corresponding current regulatory liabilities of $29 million, long-term regulatory liabilities of $14 million and long-term regulatory assets of $526 million. An adjustment to retained earnings of $12 million was recorded as at January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate setting process.

3. DIVIDENDS

During the three months ended June 30, 2009, preferred dividends in the amount of $5 million (2008 - $5 million) and common dividends in the amount of $22 million (2008 - $68 million) were declared. During the six months ended June 30, 2009, preferred dividends in the amount of $9 million (2008 - $9 million) and common dividends in the amount of $126 million (2008 - $105 million) were declared.

4. LONG-TERM DEBT

During the six months ended June 30, 2009, Hydro One issued three additional notes under the Company's Medium-Term Note Program.

The first issue on January 13, 2009 was an additional offering of medium term notes with a principal amount of $100 million having a term of 1.8 years with a coupon rate of 3.89%. The notes are due on November 19, 2010. The original issue, on November 19, 2008 had a principal amount of $100 million, bringing the total amount outstanding for this issue to $200 million.

The second issue on January 14, 2009 was an additional offering of medium term notes with a principal amount of $200 million having a term of 4.8 years with a coupon rate of 5.0%. The notes are due on November 12, 2013. The original issue, on November 10, 2008 had a principal amount of $400 million, bringing the total amount outstanding for this issue to $600 million.

The third issue on March 3, 2009 was a medium term note with a principal amount of $300 million having a term of 30 years with a coupon rate of 6.03%. The notes are due on March 3, 2039.

In the first quarter, the Company entered into three forward rate agreements in order to lock-in three interest rate resets on the floating rate it pays on a $250 million interest rate swap with settlement dates of March 3, 2009, June 3, 2009 and September 3, 2009 respectively. The three forward rate agreements are classified as held-for-trading and measured at fair value. The cash settlements on the first and second forward rate agreements were not significant and were made on March 3 and June 3, 2009 respectively. As at June 30, 2009, the fair value of the third forward rate agreement is insignificant.

5. EMPLOYEE FUTURE BENEFITS

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 of 2008, inclusive of a related interest credit of $6 million. The pension asset transfer took place in the second quarter of 2008.

Total benefit costs are as follows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2009**	**2008**	**2009**	**2008**
Pension				
Net periodic benefit cost	33	10	65	20
Pension fund contribution	27	25	56	50
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	9	22	19
Charged to results of operations	17	16	34	31
Employee Future Benefits Other than Pension				
Net periodic benefit cost	20	22	40	45
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	8	9	16	18
Charged to results of operations	12	13	24	27

6. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

7. 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 June 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2009				
Segment profit				
Revenues	271	803	16	1,090
Purchased power	-	518	-	518
Operation, maintenance and administration	120	147	14	281
Depreciation and amortization	57	69	3	129
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	94	69	(1)	162
Financing charges				74
Income before provision for payments in lieu of corporate income taxes				88
Capital expenditures	218	163	2	383
2008				
Segment profit				
Revenues	293	749	13	1,055
Purchased power	-	483	-	483
Operation, maintenance and administration	105	138	12	255
Depreciation and amortization	62	68	2	132
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	126	60	(1)	185
Financing charges				75
Income before provision for payments in lieu of corporate income taxes				110
Capital expenditures	153	146	4	303

Six months ended June 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2009				
Segment profit				
Revenues	573	1,789	31	2,393
Purchased power	-	1,184	-	1,184
Operation, maintenance and administration	223	274	27	524
Depreciation and amortization	115	133	5	253
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	235	198	(1)	432
Financing charges				146
Income before provision for payments in lieu of corporate income taxes				286
Capital expenditures	405	311	3	719
2008				
Segment profit				
Revenues	597	1,657	23	2,277
Purchased power	-	1,079	-	1,079
Operation, maintenance and administration	202	253	21	476
Depreciation and amortization	121	138	3	262
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	274	187	(1)	460
Financing charges				144
Income before provision for payments in lieu of corporate income taxes				316
Capital expenditures	260	248	6	514

(Canadian dollars in millions)	**June 30, 2009**	**December 31, 2008**
Total assets		
Transmission	8,667	7,877
Distribution	6,214	5,873
Other	121	126
	15,002	13,876

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

8. SUBSEQUENT EVENTS

On July 16, 2009, 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 $300 million having a 31-year term with a coupon rate of 5.49%. The notes are due on July 16, 2040.

On July 27, 2009, the Company filed a base shelf prospectus to renew our Medium-Term Note Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million, all of which currently remains available until August 2011.

9. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2009 unaudited interim Consolidated Financial Statements.