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, 2012 to the three and six months ended June 30, 2011, respectively. On January 1, 2012, Hydro One Inc. (Hydro One) adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting. Comparative 2011 information is presented under US GAAP, unless otherwise noted.

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2012	2011	$ Change	% Change	2012	2011	$ Change	% Change
Transmission	370	337	33	10	731	688	43	6
Distribution	974	915	59	6	2,065	2,008	57	3
Other	15	16	(1)	(6)	31	32	(1)	(3)
	1,359	1,268	91	7	2,827	2,728	99	4
Average Ontario 60-minute peak demand (MW) [1]	21,029	20,519	510	2	20,870	21,138	(268)	(1)
Distribution - units distributed to customers (TWh) [1]	6.7	6.5	0.2	3	14.5	14.8	(0.3)	(2)

[1] System-related statistics are preliminary

Electricity demand generally follows normal weather-related variations, and consequently, 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 primarily consist of our transmission tariff, which is based on the monthly peak electricity demand 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, as demonstrated by our first quartile reliability results. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets and ancillary revenues which are mostly attributable to maintenance services provided primarily to generators and secondary use of our land rights.

Our transmission revenues were higher by $33 million, or 10%, in the second quarter of 2012, and by $43 million, or 6%, in the first six months of 2012, compared to the same periods in 2011. On December 23, 2010, the Ontario Energy Board (OEB) rendered its Decision With Reasons on our 2011 and 2012 transmission rate applications. This decision followed extensive oral and written reviews of our evidence submitted for the necessary funding in support of system requirements. On November 23, 2011, the OEB issued its Decision With Reasons which approved the use of US GAAP as the basis for setting rates for our Transmission Business. In that decision, the OEB made adjustments to our previously approved 2012 transmission revenue requirement, capital expenditure levels and rate base, consistent with those proposed in our evidence. On December 20, 2011, effective January 1, 2012, the OEB approved new transmission tariff rates for 2012 that reflect the inclusion of new capital investments in our transmission rate base effective January 1, 2012. These new assets will support our aging critical infrastructure and the Province of Ontario’s (Province) supply mix objectives for generation, including off-coal initiatives and investments in support of the Green Energy Act (GEA). These decisions resulted in higher transmission revenues of $26 million and $52 million for the three and six months ended June 30, 2012, respectively, compared to the same periods in 2011.

Our 2012 transmission revenues also increased due to a higher average monthly peak demand experienced during the second quarter of 2012. The average Ontario 60-minute peak demand was 510 MW higher in the second quarter of 2012 than in the same period in 2011, resulting in higher revenues of $13 million. This increase in demand was attributable to warmer weather experienced in the second quarter of 2012, compared to 2011. This increase in our transmission revenues was partially offset by a $2 million decrease associated with OEB-approved regulatory accounts, a $2 million decrease following the completion of recovery of a regulatory account effective December 31, 2011, as well as a $2 million decrease in transmission-related external revenues.

The increase in our 2012 transmission revenues related to OEB rate decisions for the six months ended June 30, 2012 was partially offset by a $5 million decrease following the completion of recovery of a transmission regulatory account effective December 31, 2011, a $2 million reduction associated with OEB-approved regulatory accounts, and a $2 million decrease in transmission-related external revenues and lower average monthly peak demand experienced during the period.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our Distribution Business. Our consolidated Distribution Business consists of the separate distribution businesses of our subsidiaries Hydro One Networks Inc. (Hydro One Networks), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), and Hydro One Remote Communities Inc. (Hydro One Remote Communities). Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution services revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries as well as miscellaneous charges, such as those charged for late payments.

Our distribution revenues increased by $59 million, or 6%, in the second quarter of 2012, and by $57 million, or 3%, in the first six months of 2012, compared to 2011. These increases were primarily due to the recovery of higher purchased power costs of $53 million and $63 million for the three and six months ended June 30, 2012, respectively, as described below under "Purchased Power". Our distribution revenues were also higher due to $4 million and $9 million revenue increases for the three and six months ended June 30, 2012, respectively, related to our placement of new smart grid and smart meter investments in-service. These investments are currently recovered through separate rate mechanisms.

Our second quarter revenues also increased by $2 million as we experienced slightly higher energy consumption from warmer weather experienced in the second quarter of 2012 compared to 2011. The increase in our distribution revenues for the six months ended June 30, 2012 was partially offset by a $15 million decrease due to lower energy consumption in the six months ended June 30, 2012, resulting primarily from the milder winter experienced in 2012 compared to 2011.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) 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 and a separate pricing structure for RPP customers on time-of-use (TOU) billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing in May 2010, and a large majority of our RPP customers are now on TOU billing. 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 for the reporting and comparative periods is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3
May 1, 2012	600	750	7.5	8.8

RPP TOU		**Rates (cents/kWh)**	
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5

Purchased power costs increased by $53 million, or 9%, in the second quarter of 2012, and by $63 million, or 5%, in the first six months of 2012, compared to the same periods in 2011.

The increase in our second quarter purchased power costs was primarily due to an increase of $27 million from changes in the OEB's RPP rates for residential and other eligible customers, a $20 million increase resulting from higher electricity demand, and a $8 million increase due to higher transmission charges resulting from the OEB transmission rate decision effective January 1, 2012. The increase in our 2012 second quarter purchased power costs was partially offset by a $2 million reduction in wholesale market service charges levied by the IESO, compared to 2011.

The increase in our purchased power costs for the six months ended June 30, 2012 was primarily due to an increase of $63 million resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $17 million increase resulting from the OEB transmission rate decision effective January 1, 2012, and an $11 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP. The increase for the six months ended June 30, 2012 was partially offset by a $21 million decrease related to lower electricity demand, and a $7 million reduction in wholesale market service charges levied by the IESO, compared to 2011.

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 related to certain of our transmission and distribution facilities.

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)	2012	2011	$ Change	% Change	2012	2011	$ Change	% Change
Transmission	102	104	(2)	(2)	214	210	4	2
Distribution	156	155	1	1	296	297	(1)	-
Other	20	16	4	25	30	30	-	-
	278	275	3	1	540	537	3	1

Our Company continues to focus on managing costs, which resulted in a slight increase in total operation, maintenance and administration expenditures in the second quarter and the first six months of 2012, as compared to the same periods in 2011.

Transmission

Transmission operation, maintenance and administration costs incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $2 million, or 2%, to $102 million in the second quarter of 2012, and increased by $4 million, or 2%, to $214 million in the first six months of 2012, compared to the same periods in 2011. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program costs decreased by $4 million in the second quarter of 2012 and by $2 million in the first six months of 2012, compared to 2011, mainly due to lower demand for station-related corrective maintenance, particularly for power equipment, partially offset by increased expenditures related to the Ontario Power Authority's (OPA) recommendation to increase short circuit and/or transformer capacity at 10 of our transmission stations to enable the connection of small renewable projects, for which recovery is restricted (see "Future Capital Expenditures"). Expenditures in support of our transmission system increased by $2 million in the second quarter of 2012 and by $6 million in the first six months of 2012, compared to 2011, mainly due to higher information technology expenditures relating to service contracts, which were partially offset by management cost reduction initiatives.

Distribution

Distribution operation, maintenance and administration costs required to maintain our low-voltage distribution system increased by $1 million in the second quarter of 2012, and decreased by $1 million in the first six months of 2012, compared to 2011. Our work program expenditures were unchanged in the second quarter of 2012, and increased by $1 million in the first six months of 2012, compared to 2011, mainly due to increased forestry program expenditures, resulting from more favourable weather conditions in 2012. The increase in forestry program expenditures in the second quarter of 2012 was offset by decreased power restoration expenditures resulting from lower storm activity in 2012, compared to 2011. Our expenditures in support of our distribution system increased by $1 million in the second quarter of 2012, and decreased by $2 million in the first six months of 2012, compared to 2011, mainly due to higher information technology expenses and investments supporting the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project, which were more than offset by a redirection of resources in support of our Transmission Business and cost reduction initiatives in the first six months of 2012.

Depreciation and Amortization

Depreciation and amortization expense increased by $7 million, or 5%, in the second quarter of 2012, and by $15 million, or 5%, in the first six months of 2012, compared to 2011. These increases were attributable to higher depreciation expense of $8 million and $17 million in the second quarter and the first six months of 2012, respectively, compared to 2011, related to our placement of new assets in service consistent with our ongoing capital work program. These increases were partially offset by lower asset removal costs during the three and six months ended June 30, 2012, compared to 2011.

Financing Charges

Financing charges increased by $4 million, or 5%, in the second quarter of 2012, and by $3 million, or 2%, in the first six months of 2012, compared to 2011. These increases were primarily due to higher interest expense, related to our long-term debt, of $4 million and $6 million in the second quarter and the first six months of 2012, respectively. This increase was associated with a higher average level of debt, partially offset by a lower average effective interest rate. Higher financing charges in the first six months of 2012 were partially offset by a $3 million increase in interest capitalized, reflecting higher interest capitalization rates used on construction in progress.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes decreased by $3 million, or 11%, in the second quarter of 2012, and by $10 million, or 15%, in the first six months of 2012, compared to 2011. These decreases resulted from a reduction in the statutory tax rate from 28.25% to 26.50%, as well as changes in net temporary differences, partially offset by higher levels of pre-tax income, compared to the same periods in 2011.

Net Income

Net income of $169 million for the second quarter of 2012 and $379 million for the first six months of 2012 was higher than our comparable 2011 net income by $27 million, or 19%, and by $25 million, or 7%, respectively.

These increases were primarily due to higher revenues resulting from new OEB-approved Uniform Transmission Rates that were effective January 1, 2012 and which reflect capital investments to address our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and investments in support of the GEA. Second quarter transmission revenues were further impacted by a higher average Ontario 60-minute peak demand. Increased revenues for the first six months of 2012 were partially offset by lower distribution energy consumption resulting from the mild winter in 2012.

Our net income was also positively impacted by lower payments in lieu of corporate income taxes resulting from a lower statutory income tax rate that became effective January 1, 2012, as well as changes in net temporary differences. In addition, our 2012 net income reflects higher depreciation and amortization costs resulting from our placement of new assets in service consistent with our increased capital work program.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2010 through June 30, 2012. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements 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)	**2012**		**2011**				**2010**	
Quarter ended	**Jun.30**	**Mar.31**	**Dec.31**	**Sep.30**	**Jun.30**	**Mar.31**	**Dec.31**[2]	**Sep.30**[2]
Total revenue[1]	1,359	1,468	1,359	1,384	1,268	1,460	1,280	1,360
Net income[1]	169	210	120	167	142	212	99	218
Net income to common shareholder[1]	164	206	115	163	137	208	94	214

[1] The electricity demand generally follows normal weather-related variations, and consequently, 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] Based on Canadian GAAP. US GAAP results would not differ significantly.

LIQUIDITY AND CAPITAL RESOURCES

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

Summary of Sources and Uses of Cash

	Three months ended June 30		**Six months ended June 30**	
(Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Operating activities	217	334	454	574
Financing activities				
Long-term debt issued	425	-	725	300
Long-term debt retired	-	-	-	(250)
Dividends paid	(30)	(42)	(311)	(84)
Investing activities				
Capital expenditures	(350)	(345)	(667)	(640)
Other financing and investing activities	2	17	(4)	46
Net change in cash and cash equivalents	264	(36)	197	(54)

Operating Activities

Net cash from operating activities decreased by $117 million to $217 million in the second quarter of 2012, and by $120 to $454 million in the first six months of 2012, compared to 2011. These decreases were primarily due to pension plan contributions paid during the second quarter of 2012 that resulted in a prepaid pension contributions asset, partly offset by higher net income compared to the prior year. During the second quarter of 2012, we experienced growth in accounts receivable balances resulting from higher revenues, which were more than offset by improved accounts receivable collection cycles during the first six months of 2012. In addition, for the six months ended June 30, 2012, we experienced a reduction in taxes payable, resulting from a payment made in the first quarter of 2012 related to the 2011 taxation year.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of our $1,250 million committed revolving credit facility with a syndicate of banks, which matures in June 2017, and our holding of $250 million of Province of Ontario Floating-Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

As at June 30, 2012, we had $8,726 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2012 and 2051. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. As at June 30, 2012, $1,875 million remained available until September 2013.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.[1]	Prime-1	A1
S&P[2]	A-1	A+

[1] On April 27, 2012, Moody's Investors Service Inc. downgraded our senior unsecured rating to A1 from Aa3.
[2] On April 25, 2012, S&P revised their outlook on our company to negative from stable.

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 agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations as at June 30, 2012.

In the second quarter and the first six months of 2012, we successfully issued $425 million and $725 million, respectively, in cost-effective long-term debt under our MTN Program, and no long-term debt matured in 2012. In the first six months of 2011, we issued $300 million in long-term debt under our MTN Program and repaid $250 million in maturing long-term debt, all in the first quarter. In the first six months of 2012 and 2011, we did not issue any short-term notes and had no short-term notes outstanding as at either June 30, 2012 or June 30, 2011.

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

In the second quarter of 2012, we paid dividends to the Province in the amount of $30 million, consisting of $25 million in common dividends and $5 million in preferred dividends. In the second quarter of 2011, we paid common dividends of $37 million and preferred dividends of $5 million.

In the first six months of 2012, we paid dividends to the Province in the amount of $311 million, consisting of $302 million in common dividends and $9 million in preferred dividends. In the first six months of 2011, we paid common dividends of $75 million and preferred dividends of $9 million.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our shareholder. In order to ensure ongoing effective access to capital, we target an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	**2012**	**2011**	**$ Change**	**% Change**	**2012**	**2011**	**$ Change**	**% Change**
Transmission	189	189	-	-	376	361	15	4
Distribution	161	155	6	4	288	278	10	4
Other	-	1	(1)	(100)	3	1	2	200
	350	345	5	1	667	640	27	4

Transmission

Transmission capital expenditures were unchanged at $189 million in the second quarter of 2012, and increased by $15 million, or 4%, to $376 million in the first six months of 2012, compared to the same periods in 2011.

Investments to expand and reinforce our transmission system were $73 million in the second quarter and $166 million for the first six months of 2012, representing respective reductions of $20 million and $17 million, compared to 2011. The majority of our expenditures were made on inter-area network projects to support the Province’s supply mix objectives for generation, although we continue to make significant investments on load customer connection and local area supply projects to address growing loads. The 2012 decrease in our expenditures results from the completion of several large projects in 2011. Major inter-area network projects completed and put into service in 2011 included the installation of complex static var compensators (SVCs) at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations. Also contributing to the variance were lower expenditures in 2012 related to our Bruce to Milton Transmission Reinforcement Project connecting refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. This project was successfully declared in-service ahead of schedule on May 14, 2012 and contributed approximately half of our total 2012 investments to expand and reinforce our transmission system. The impact of the reductions in expenditures in both periods was partially offset by increases in our expenditures resulting from local area supply projects progressing into their build phases, investments in our transformer stations related to the Advanced Distribution System (ADS) Project, which supports clean Distributed Generation (DG) connected to our transmission system consistent with the GEA, as well as increased investments related to our transmission projects and upgrades to safely and reliably accommodate additional renewable energy.

Our local area supply project expenditures include investments in our Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure and increase the load supply capacity to ensure reliability of supply to customers in the area. Together with Toronto Hydro-Electric System Limited, we continue to invest in our Midtown Electricity Infrastructure Renewal Project to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work is progressing at our Hearn Switching Station to rebuild an existing switchyard that has reached its end-of-life. This project will also increase short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto. In 2012, we also incurred expenditures related to our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliability in the Woodstock area. This project was put into service in March 2012.

Expenditures to sustain our existing transmission system were $104 million in the second quarter and $186 million in the first six months of 2012, representing increases of $16 million and $25 million, respectively, compared to 2011. These increases were primarily related to the refurbishment and replacement of end-of-life equipment at our transformer stations in order to improve reliability.

Our other transmission capital expenditures were $12 million in the second quarter and $24 million in the first six months of 2012, representing increases of $4 million and $7 million, respectively, compared to 2011. The majority of these expenditures were related to fleet acquisitions and to information technology investments.

Distribution

Our distribution capital expenditures increased by $6 million, or 4%, in the second quarter, and by $10 million, or 4%, in the first six months of 2012, compared to 2011.

Capital investments to expand and reinforce our distribution network were $78 million in the second quarter and $133 million in the first six months of 2012, representing increases of $10 million and $2 million, respectively, compared to 2011. We experienced increases in 2012 related to our continued investments in our ADS Project, a multi-year initiative to identify, deploy, analyze and assess equipment and applications to modernize our distribution system. The ADS Project is anticipated to improve outage restoration, reduce construction and ongoing maintenance costs, and reduce line losses. Increased capital expenditures in 2012 were also due to investments related to our other distribution projects and upgrades to safely and reliably accommodate additional renewable energy, and higher volumes of new customer connections and upgrades, partially offset by reduced expenditures within our Smart Meter Project as it nears completion.

Expenditures to sustain our distribution system were $63 million in the second quarter and $108 million in the first six months of 2012, representing decreases of $3 million and $5 million, respectively, compared to 2011. Our sustainment program reduction in 2012 was related to lower storm restoration work given two major storms in Ontario in 2011. This impact was partially offset by increased work within our wood pole replacement and lines programs, as resources were utilized in 2012 to advance these programs given favourable weather conditions.

Other distribution capital expenditures were $20 million in the second quarter and $47 million for the first six months of 2012, representing a decrease of $1 million and an increase of $13 million, respectively, compared to 2011. The year-to-date variance is primarily attributable to expenditures for the CIS phase of our entity-wide information system replacement and improvement project. In addition to replacing end-of-life systems, this implementation will result in process improvements that are expected to provide many benefits, including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information.

Future Capital Expenditures

Our capital expenditures for 2012 are budgeted at approximately $1,800 million. Our 2012 capital budgets for our transmission and distribution businesses are about $1,000 million and $800 million, respectively. Consolidated capital expenditures are also expected to be approximately $1,800 million in each of 2013 and 2014. These expenditure levels reflect meeting the sustainment requirements of our aging infrastructure. Our sustainment program is budgeted at approximately $700 million in 2012, $950 million in 2013 and $1,000 million in 2014. Our development projects include the ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements, and requirements to enable DG. Our development expenditures are budgeted at approximately $750 million in 2012, $600 million in 2013 and $550 million in 2014. These development investments also reflect customer demand work. Other capital expenditures are budgeted at approximately $350 million in 2012 and $250 million in each of 2013 and 2014. These expenditures include investments to replace our end-of-life customer billing system and to realize increased productivity from our enterprise-wide SAP platform. Our capital expenditures for 2012 are anticipated to be lower than budget by approximately $165 million, primarily due to changes in the cost and timing of certain large transmission projects, for example the Midtown Electricity Infrastructure Renewal Project, as well as lower distribution development including DG capital expenditures reflecting a lower volume of activity due to proponent delays and lower than anticipated proponent applications received by our Company.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. The estimated capital expenditures associated with these projects and upgrades to the system are anticipated to be up to approximately $700 million over a period to the in-service dates of these projects and the applicable expenditures are reflected in our budgets. On February 28, 2011, the OEB amended our subsidiary Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy. This licence amendment requires Hydro One Networks to develop and seek approvals for these projects in accordance with recommendations from the OPA. In a letter dated April 7, 2011, to accommodate small-scale renewable generation, the OPA provided the scope and timing requirements to increase short circuit and/or transformer capacity at 10 of 15 transformer stations noted in the licence. Six of these upgrades have been completed and we are currently anticipating that one additional station upgrade will be placed in-service later in 2012. For the remaining three upgrades, alternative solutions have been identified. The overall capital cost for the stations is estimated to be up to $40 million. On June 30, 2011, we received a letter from the OPA recommending the scope and timing to reconductor two circuits between Sarnia and London. This West of London Transmission Upgrade Project will enable the connection of additional renewable generation in the west of London area. On March 28, 2012, we filed a Section 92 leave-to-construct application with the OEB for our West of London Transmission Upgrade Project. This project has a required in-service date of December 2014. On October 3, 2011, we received a letter from the OPA recommending the scope and timing of a Southwestern Ontario Reactive Compensation Priority Project, formerly known as the Southwestern Ontario Series Compensation Project. After consideration of the options, the OPA recommended that we install an SVC at our Milton Switching Station to increase the transmission capability of the Bruce transmission system. A new transmission line west of the City of London was also included in the Hydro One Transmission Licence Amendment. We have not yet received a recommendation from the OPA regarding the construction of this line.

In accordance with the memorandum of agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from micro Feed-in Tariff (FIT) and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investments and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendment made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our company, including the timing of any such decisions. In the first six months of 2011 and the full year 2011, we spent approximately $2 million and $21 million, respectively, on these projects, and in the first six months of 2012, we spent approximately $12 million. Of the amounts spent, $2 million and $19 million was charged to results of operations in the first six months of 2011 and the full year 2011, respectively, and in the first six months of 2012, $11 million was charged to results of operations.

In August 2010, the OEB introduced a framework for competitive designation for the development of eligible transmission projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework. We do not plan to undertake large capital expenditures without a reasonable expectation of recovering them in our rates, with the exception of the transformer station upgrades noted above.

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, 2012 (Canadian dollars in millions)	**Total**	**2012**[1]	**2013/2014**	**2015/2016**	**After 2016**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	8,700	600	1,350	1,000	5,750
Long-term debt – interest payments	6,964	216	765	663	5,320
Inergi LP (Inergi) outsourcing agreement[2]	352	69	262	21	-
Operating lease commitments	55	5	19	11	20
Environmental and asset retirement obligations[3]	322	23	61	48	190
Total Contractual Obligations	16,393	913	2,457	1,743	11,280
Other Commercial Commitments *(by year of expiry)*					
Bank line[4]	1,250	-	-	-	1,250
Letters of credit[5]	135	124	11	-	-
Guarantees[5]	326	326	-	-	-
Pension[6]	327	-	313	14	-
Total Other Commercial Commitments	2,038	450	324	14	1,250

1 The amounts disclosed represent the amounts due over the period July 1, 2012 to December 31, 2012.

2 On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

3 We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

4 In support of our liquidity requirements, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2017.

5 We currently have outstanding bank letters of credit of $124 million relating to retirement compensation arrangements. On April 27, 2012, our highest credit rating declined from the "Aa" category to the "A" category. Based on this credit rating category, we provided letters of credit to the IESO in the amount of $10 million to meet our current prudential requirement. The other $1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million, and on behalf of two distributors using guarantees of up to a maximum of $660 thousand.

6 Contributions to the Hydro One pension fund are generally made one month in arrears. The 2012, 2013 and 2014 minimum contributions are based on an actuarial valuation filed in May 2012 and effective December 31, 2011. Based on expected levels of 2012 pensionable earnings, our total 2012 annual pension contributions of approximately $163 million were paid during the six months ended June 30, 2012. Future minimum contributions beyond 2014

will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2014 are not estimable at this time.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with this debt is recorded under financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Consolidated Statements of Operations and Comprehensive Income or as a cost of 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 the Province. The year-over-year changes related to these amounts are described more fully in the 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 and property taxes, which are paid or payable to the Ontario Electricity Financial Corporation (OEFC). In January 2010, we purchased $250 million of Province of Ontario Floating-Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first six months of 2012, we contributed $163 million to our pension plan and incurred $104 million in net periodic pension benefit cost. An actuarial valuation filed in May 2012 and effective December 31, 2011 did not result in significant changes to our 2012 required contributions or our 2012 net periodic benefit cost. Actuarial valuations are minimally required to be filed every three years. We currently estimate our total annual pension contributions to be approximately $163 million, $162 million, and $165 million for 2012, 2013, and 2014, respectively, based on the projected level of pensionable earnings and the same actuarial valuation effective December 31, 2011. Future minimum contributions beyond 2014 will be based on the actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of about 3.6% in the first six months of 2012.

TRANSITION TO US GAAP

Accounting Framework for External Reporting

In 2011, the Ontario Securities Commission (OSC) and our Board of Directors approved our application to adopt US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, without becoming a Securities and Exchange Commission (SEC) registrant, for our 2012, 2013 and 2014 fiscal years. As a result, our unaudited interim Consolidated Financial Statements and accompanying notes as at, and for the three and six months ended June 30, 2012 have been prepared in accordance with US GAAP. Our first US GAAP unaudited interim Consolidated Financial Statements were as at, and for the three months ended March 31, 2012. Our first US GAAP annual Consolidated Financial Statements will be dated December 31, 2012.

Our company's Consolidated Financial Statements were prepared in accordance with Canadian GAAP until December 31, 2011. Canadian GAAP differs in some areas from US GAAP as disclosed in the reconciliation to US GAAP included in Note 17 to the unaudited interim Consolidated Financial Statements as at and for the three and six months ended June 30, 2012. Descriptions of the effect of the transition from Canadian GAAP to US GAAP on our financial position, financial performance and cash flows as at and for the year ended December 31, 2011 are also provided in Note 17 to our unaudited interim Consolidated Financial Statements for the period ended June 30, 2012. The accounting policies set out in the unaudited interim Consolidated Financial Statements for the period ended June 30, 2012 have been consistently applied to all the periods presented. The comparative figures in respect of 2011 were retrospectively restated effective January 1, 2011 to reflect our adoption of US GAAP.

Accounting Framework for Rate-Setting

Consistent with the OSC's decision to approve our adoption of US GAAP, two of our subsidiaries, Hydro One Networks and Hydro One Remote Communities requested that the OEB approve the adoption of US GAAP as the basis for future rate-setting and regulatory accounting and reporting in place of its standard modified International Financial Reporting Standards (IFRS) basis. The OEB approved Hydro One Networks' request to adopt US GAAP for its regulated distribution and transmission businesses, and approved Hydro One Remote Communities' request to adopt US GAAP as its approved basis for rate-setting, all effective January 1, 2012. We did not make a request to adopt US GAAP for rate-setting purposes on behalf of our subsidiary, Hydro One Brampton Networks. Hydro One Brampton Networks has implemented IFRS for its 2012 fiscal year. As a result, Hydro One Brampton Networks will have its rates set based on modified IFRS once its current incentive rate-setting period is complete.

Debt Covenants

None of our financial covenants were impacted by our conversion to US GAAP.

Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Our transition to US GAAP did not result in any significant revisions to our internal controls over financial reporting and disclosure controls and procedures.

Financial Reporting Expertise

Given the similarities between US GAAP and Canadian GAAP for our company, there has also been no significant impact from the transition to US GAAP with respect to financial reporting expertise. Our US GAAP training efforts have been focused on specific areas of difference between the two accounting frameworks and these efforts have been targeted to specific finance staff, senior executive management and the Audit and Finance Committee of our Board of Directors. We continue to provide additional training to our other finance and operational staff, concentrating on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs. During the remainder of 2012, we will focus our US GAAP training on new accounting and reporting developments and on emerging issues.

Information Systems

Given the similarities between US GAAP and Canadian GAAP, we did not experience any significant impacts from the transition to US GAAP with respect to our information systems.

IFRS

Prior to our adoption of US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, we had planned to adopt IFRS effective January 1, 2012, with comparative restatement of our 2011 results. Accordingly, by mid-2011, we had substantively completed our four-phase IFRS conversion project, which included separate diagnostic, design and planning, solution development, and implementation phases. Our IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on our financial statements, a review and upgrade of our information systems to meet IFRS requirements, an assessment of our internal controls over financial reporting and disclosure controls and processes, as well as training of our key finance and operational staff.

As a result of our 2011 decision to adopt US GAAP, our IFRS conversion project efforts were effectively halted. However, our IFRS conversion work has been, and will continue to be, managed in such a way that it can effectively be restarted if a future transition to IFRS is required. We continue to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

Training of our key finance and operational staff commenced in 2007, and continues on a reduced but on-going basis, as we have certain subsidiaries that are required to prepare their unconsolidated financial statements in accordance with IFRS. IFRS training was also previously provided to our Audit and Finance Committee and senior executive management. In 2012, we will continue to provide IFRS training to specific staff with a focus on new IFRS accounting and reporting developments and emerging issues.

Our company has the customary financial 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. Depending on the outcome of various international standard setting initiatives, including the Rate Regulated Accounting Project, a potential future adoption of IFRS could result in changes to our financial position and increased volatility in our results of operations that could impact our debt covenants. We continue to monitor the potential impact that an IFRS conversion could have under various scenarios.

As part of a company-wide information systems improvement project, many of our major financial systems were replaced in 2008 and 2009. Our new financial systems were designed with maximum flexibility given the uncertainty of the outcome of certain impactive International Accounting Standards Board projects. Our financial systems have the ability and capacity to handle current accounting and reporting processes in accordance with IFRS, should that be required in the future.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

To optimize our customer service operations, we have started the final phase of our SAP enterprise-wide information system by initiating our CIS Project. This new system will increase productivity by replacing two legacy applications currently providing service to our distribution customers and key constituents for billing, customer contacts, field services, settlements and customer choice administration. With the design phase complete, the CIS Project is currently in the build and test phases. During these phases, internal controls will be tested for adequacy and effectiveness with any remediation effort to be completed prior to the go-live date. In addition to the benefits associated with CIS, we continue to leverage our other SAP enterprise systems to gain other productivity improvements.

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 unaudited interim Consolidated Financial Statements for the period ended June 30, 2012, 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. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the unaudited interim Consolidated Financial Statements.

RECENT DEVELOPMENTS

Debt Issuances

On July 31, 2012, we issued $75 million notes under our MTN Program with a maturity date of July 31, 2062 and a coupon rate of 3.79%.

On May 22, 2012, we issued $300 million and $125 million notes under our MTM Program with maturity dates of January 13, 2022 and December 22, 2051, and coupon rates of 3.20% and 4.00%, respectively. These notes were additional offerings of notes originally issued on January 13, 2012 for $300 million and December 22, 2011 for $100 million. These additional issuances bring the total amounts outstanding for these debt issues to $600 million and $225 million, respectively.

Ontario's FIT Program

On July 12, 2012, the OPA re-launched the microFIT Program, following an April 5, 2012 letter received from the Ministry of Energy directing it to implement recommendations from the Ontario Government's FIT Program Review. Highlights of changes implemented include encouraging greater community and aboriginal participation and the protection of agricultural lands. The FIT Program will be re-launched to reflect recommendations from the review at a later date.

Provincial Budget

On June 20, 2012, Bill 55, *Strong Action for Ontario Act (Budget Measures)* received royal assent. Bill 55 is aimed at eliminating Ontario's deficit by 2017-2018, and includes several items aimed at reducing costs within the greater public sector, within the energy sector specifically, and on energy bills. In support of these initiatives, the Ontario government will engage an independent consultant to identify opportunities for efficiencies and benchmark Hydro One against comparable entities.

Bruce to Milton Transmission Reinforcement Project

In May 2012, our Bruce to Milton Transmission Reinforcement Project was declared in-service, ahead of the December 2012 target. The new line will connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area.

Agreement with Saugeen Ojibway Nation

On June 18, 2012, our subsidiary Hydro One Networks, and the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively known as the Saugeen Ojibway Nation (SON), entered into an agreement which contemplates a new Limited Partnership (LP) to hold only the lines and related land rights of our recently completed Bruce to Milton Transmission Reinforcement Project. The carrying value of these assets is expected to be approximately $600 million when they are transferred to the LP. Under the terms of this agreement, the SON will be eligible to purchase a non-controlling equity interest in the LP at fair value. The LP will be a rate regulated entity under the jurisdiction of the OEB. Transfer of the assets to the LP and subsequent sale of an equity interest to the SON are both subject to the receipt of future regulatory approvals from the OEB.

Retirement of our Chief Executive Officer (CEO)

On June 13, 2012, Laura Formusa, our President and CEO, informed the Board of Directors that she will retire, effective December 31, 2012. Our Board of Directors has made it its priority to ensure we have a robust succession plan in place. Ms. Formusa's retirement at the end of 2012 allows the Board of Directors to execute the succession plan in a manner that provides for an orderly succession process. The Board of Directors has initiated this process to identify our new President and CEO.

East-West Tie LP (EWT LP)

On May 31, 2012, EWT LP, an equal partnership of three entities including Hydro One, received approval from the OEB for its transmission licence, which is required to participate in the East-West Tie Line bid process. On July 12, 2012, the OEB announced that applications for designation of the East-West Tie Line must be filed no later than January 4, 2013.

OEB Rate Applications

On May 28, 2012, our subsidiary Hydro One Networks filed a revenue requirement and cost-of-service rate application for 2013 and 2014 transmission rates. The application seeks approval for revenue requirements of approximately $1,464 million and $1,557 million for 2013 and 2014, respectively. This represents an estimated increase in rates of less than 1% in 2013 and 9% in 2014. These increases are estimated to result in no impact on an average customer's total monthly bill in 2013 and a less than 1% increase in 2014.

On May 28, 2012, Hydro One Networks also filed an Incentive Regulation Mechanism rate application for 2013 distribution rates, to be effective January 1, 2013. If approved as filed, distribution rates for a residential customer would rise by approximately 2.9%. Including previously OEB approved Retail Transmission Service Rate (RTSR) adjustments for 2011 and 2012, the total bill impact for 2013 would be approximately 2.1%. A distribution rate application for 2012 was not filed, and therefore, 2012 tariff rates were held at the 2011 levels.

SouthPoint Wind Legal Claim

SouthPoint Wind has discontinued its claims against the Ontario government ministries and Environment Canada because the claims were not properly served, leaving Hydro One Networks and the OPA as defendants to the claim received on April 4, 2012. The reason for the discontinuance is that the plaintiff failed to give the above mentioned defendants proper notice, as required by law for proceedings against government entities, before issuing the claim. As the statement of claim serves as sufficient notice, SouthPoint Wind can issue a new claim against the government defendants. Our company is not aware whether SouthPoint Wind has issued a new claim against the government defendants at this time.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions, except earnings per common share and ratios)	**2012**	**2011**	**2012**	**2011**
Net income	169	142	379	354
Net cash from operating activities	217	334	454	574
Capital expenditures	350	345	667	640
Earnings per common share	1,651	1,375	3,705	3,451
Earnings coverage ratio[1]			2.70	2.65
Net asset coverage on long-term debt ratio[2]			1.75	1.81
Total debt to capitalization ratio[3]			59%	55%

[1] The earnings coverage ratio has been presented for the twelve months ended June 30, 2012 and June 30, 2011, 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, 2012 and December 31, 2011 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, 2012 and December 31, 2011 and has been calculated as total debt divided by total debt plus total shareholder's equity and preferred shares.

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 energy related revenues and profit and their trend; statements related to the use of our approved rates; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility and our long-term credit rating target; expectations regarding our financing activities; expectations about our maturing debt and interest payments; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates; expectations regarding the recoverability of large capital expenditures; statements regarding expected future capital and development expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; expectations related to OEB rate applications, including impacts of such decisions on an average residential customer's bill; statements regarding the retirement of our CEO; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi; statements relating to US GAAP and our adoption of US GAAP; statements regarding accounting related international standard setting initiatives, including the potential future adoption of IFRS and its associated impacts; statements about our agreement with SON; statements related to the FIT program; statements regarding the Ontario government; and expectations regarding future payments made under our operating leases. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", 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 delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission businesses; a stable regulatory environment; no unfavourable changes in environmental regulation; 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 sources. 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 impact of the GEA and the Province's Long-Term Energy Plan, including unexpected expenditures arising therefrom;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- unanticipated changes in electricity demand or in our costs;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks associated with changes in interest rates;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section Risk Management and Risk Factors in the 2011 Management's Discussion and Analysis (MD&A). You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at August 9, 2012. 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)

(Canadian dollars in millions, except per share amounts)	**Three months ended June 30** 2012	2011	**Six months ended June 30** 2012	2011
Revenues		*(Note 17)*		*(Note 17)*
Distribution	974	915	2,065	2,008
Transmission	370	337	731	688
Other	15	16	31	32
	1,359	1,268	2,827	2,728
Costs				
Purchased power	640	587	1,369	1,306
Operation, maintenance and administration	278	275	540	537
Depreciation and amortization	158	151	310	295
	1,076	1,013	2,219	2,138
Income before financing charges and provision for payments in lieu of corporate income taxes	283	255	608	590
Financing charges *(Note 4)*	90	86	173	170
Income before provision for payments in lieu of corporate income taxes	193	169	435	420
Provision for payments in lieu of corporate income taxes *(Note 5)*	24	27	56	66
Net income	169	142	379	354
Other comprehensive income	-	-	-	-
Comprehensive income	169	142	379	354
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,651	1,375	3,705	3,451
Dividends per common share declared *(Canadian dollars) (Note 11)*	250	375	3,023	750

See accompanying notes to interim Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	**June 30, 2012**	**December 31, 2011**
Assets		*(Note 17)*
Current assets:		
Short-term investments *(Note 8)*	425	228
Accounts receivable (net of allowance for doubtful accounts - $20 million; 2011 - $18 million) *(Notes 6, 12)*	958	961
Prepaid pension contributions *(Note 9)*	83	-
Regulatory assets	28	24
Materials and supplies	23	25
Deferred income tax assets *(Note 5)*	20	19
Derivative instruments *(Note 8)*	1	1
Other	14	19
	1,552	1,277
Property, plant and equipment:		
Property, plant and equipment in service	21,940	21,008
Less: accumulated depreciation	7,918	7,679
	14,022	13,329
Construction in progress	1,106	1,436
Future use land, components and spares	141	138
	15,269	14,903
Other long-term assets:		
Regulatory assets	2,138	1,966
Long-term investment *(Notes 8, 12)*	250	250
Intangible assets (net of accumulated amortization of $280 million; 2011 - $257 million)	241	224
Goodwill	133	133
Deferred debt costs	34	32
Derivative instruments (*Note 8)*	26	33
Deferred income tax assets *(Note 5)*	15	17
Other	2	1
	2,839	2,656
Total assets	19,660	18,836

See accompanying notes to interim Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	**June 30, 2012**	**December 31, 2011**
Liabilities		*(Note 17)*
Current liabilities:		
Bank indebtedness *(Note 8)*	23	39
Accounts payable *(Note 12)*	144	154
Accrued liabilities *(Note 12)*	760	917
Accrued interest	94	85
Regulatory liabilities	26	25
Long-term debt payable within one year *(Notes 7, 8)*	600	600
	1,647	1,820
Long-term debt *(Note 7, 8)*	8,126	7,408
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 9)*	1,189	1,163
Deferred income tax liabilities *(Note 5)*	896	758
Pension benefit liability *(Note 9)*	779	779
Environmental liabilities	228	235
Regulatory liabilities	222	169
Net unamortized debt premiums	25	23
Asset retirement obligations	15	15
Long-term accounts payable and other liabilities	11	12
	3,365	3,154
Total liabilities	13,138	12,382
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Note 10)*	323	323
Shareholder's equity		
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,895	2,827
Accumulated other comprehensive loss	(10)	(10)
Total shareholder's equity	6,199	6,131
Total liabilities, preferred shares and shareholder's equity	19,660	18,836

See accompanying notes to interim Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (unaudited)

Six months ended June 30, 2012 *(Canadian dollars in millions)*	**Common Shares**	**Accumulated Other Comprehensive Loss**	**Retained Earnings**	**Total Shareholder's Equity**
January 1, 2012	3,314	(10)	2,827	6,131
Net income	-	-	379	379
Other comprehensive income	-	-	-	-
Dividends on preferred shares	-	-	(9)	(9)
Dividends on common shares	-	-	(302)	(302)
June 30, 2012	3,314	(10)	2,895	6,199

Six months ended June 30, 2011 *(Canadian dollars in millions)* *(Note 17)*	**Common Shares**	**Accumulated Other Comprehensive Loss**	**Retained Earnings**	**Total Shareholder's Equity**
January 1, 2011	3,314	(10)	2,354	5,658
Net income	-	-	354	354
Other comprehensive income	-	-	-	-
Dividends on preferred shares	-	-	(9)	(9)
Dividends on common shares	-	-	(75)	(75)
June 30, 2011	3,314	(10)	2,624	5,928

See accompanying notes to interim Consolidated Financial Statements.

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

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Operating activities		*(Note 17)*		*(Note 17)*
Net income	169	142	379	354
Environmental expenditures	(4)	(3)	(7)	(7)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	140	132	279	263
Regulatory asset and liability accounts	8	10	15	36
Deferred income taxes	(1)	1	-	3
Other	(1)	-	-	(1)
Changes in non-cash balances related to operations *(Note 13)*	(94)	52	(212)	(74)
Net cash from operating activities	217	334	454	574
Financing activities				
Long-term debt issued	425	-	725	300
Long-term debt retired	-	-	-	(250)
Dividends paid	(30)	(42)	(311)	(84)
Change in bank indebtedness	(9)	7	(16)	33
Other	2	-	1	(2)
Net cash from (used in) financing activities	388	(35)	399	(3)
Investing activities				
Capital expenditures				
Property, plant and equipment	(331)	(327)	(627)	(604)
Intangible assets	(19)	(18)	(40)	(36)
Other assets	9	10	11	15
Net cash used in investing activities	(341)	(335)	(656)	(625)
Net change in cash and cash equivalents	264	(36)	197	(54)
Cash and cash equivalents, beginning of period	161	154	228	172
Cash and cash equivalents, end of period *(Note 13)*	425	118	425	118

See accompanying notes to interim Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

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

The demand for electricity generally follows normal weather-related variations, and consequently, 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. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These unaudited interim Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc. and Hydro One Lake Erie Link Company Inc.

Intercompany transactions and balances have been eliminated.

Basis of Accounting

These unaudited interim Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). These statements are to be read in conjunction with Note 17, Transition to US GAAP, which discloses information on the Canadian GAAP to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the three and six months ended June 30, 2011 and the Consolidated Balance Sheet at December 31, 2011 have been restated under US GAAP for comparative purposes. The Company's Consolidated Financial Statements were previously prepared using Canadian GAAP.

These unaudited interim Consolidated Financial Statements do not contain all disclosures required by US GAAP for annual audited consolidated financial statements. Accordingly, they should be read in conjunction with the Company's annual Consolidated Financial Statements as at and for the year ended December 31, 2011, and Note 17 to these unaudited interim Consolidated Financial Statements for Canadian GAAP to US GAAP transition and reconciliation information. In the opinion of management, these unaudited interim Consolidated Financial Statements include all adjustments that are necessary to fairly state the financial position of Hydro One at June 30, 2012. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2012.

Hydro One performed an evaluation of subsequent events for the accompanying unaudited interim Consolidated Financial Statements and notes included through to August 9, 2012, the date these unaudited interim Consolidated Financial Statements were issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions in these unaudited interim Consolidated Financial Statements. See Note 18 - Subsequent Event.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the year they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (ARO), goodwill, asset impairment, contingencies, unbilled revenue, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are regulated by the OEB. The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. The OEB approved US GAAP as the basis for rate-setting for Hydro One Networks' Transmission Business in 2011 and for its Distribution Business on March 23, 2012. The OEB approved the use of US GAAP by Hydro One Remote Communities on April 3, 2012. Hydro One Brampton Networks' rates are expected to be set under the OEB's modified International Financial Reporting Standards framework commencing in 2015, once its current incentive regulation mechanism period is complete.

A description of previous OEB rate decisions impacting the financial results of the current and comparative periods may be found in Note 2 to the Company's annual Consolidated Financial Statements for the year ended December 31, 2011.

On March 22, 2012, the OEB issued its decision with reasons approving a rate increase of 1.08% effective May 1, 2012 for Hydro One Remote Communities, which services the far north, representing an increase of about $1 on an average residential customer's monthly bill.

Regulatory Accounting

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates monthly revenue for a period based on wholesale power purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the “more likely than not” recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50 percent likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and the corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more likely than not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more likely than not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the deferred income tax asset to report the net asset balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be utilized.

The Company has recognized regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction material held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company’s best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost including capitalized financing costs, and net of customer contributions received in aid of construction, and any accumulated impairment losses. The cost of additions, including betterments and replacements of asset components, is included on the Consolidated Balance Sheet as property, plant and equipment.

The cost of property, plant and equipment represents the original cost, consisting of direct materials, direct labour including employee benefits, contracted services, attributable financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overhead includes a portion of corporate shared costs such as finance, human resources, information technology and executive and other costs related to support functions, insurance, procurement, and fleet operations. Overhead costs, including shared corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on property, plant and equipment assets under construction and on intangible assets under development.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

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

Distribution

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

Communication

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

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

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

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt financing.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost which comprises purchased software, direct labour including employee benefits and consulting, engineering, overheads and attributable financing charges. Following initial recognition, intangible assets are carried at cost net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major administrative computer applications software assets.

Construction and Development in Progress

Construction and development in progress includes constructed assets that are not yet completed and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category. The sole exception is transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2007.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate (%) Range	Rate (%) Average
Transmission	55 years	1% - 3%	2%
Distribution	42 years	1% - 13%	2%
Communication	19 years	1% - 13%	5%
Administration and service	15 years	1% - 20%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 11%.

Depreciation rates for finite life easements are based on their contract lives. However, the majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased. Goodwill is evaluated for impairment on an annual basis in the fourth quarter, or more frequently if circumstances require. The impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

On September 15, 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-08, *Testing Goodwill for Impairment*. The revised standard is intended to reduce the cost and complexity of the annual goodwill impairment test by providing entities an option to perform a qualitative assessment to determine whether further impairment testing is necessary. An entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Moreover, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the impairment test, and then resume performing the qualitative assessment in any subsequent period.

The Company determined that goodwill was not impaired at December 31, 2011. During the six months ended June 30, 2012, no events occurred or circumstances changed that would, more likely than not indicate that the fair value of a reporting unit had been reduced below its carrying amount. Therefore, goodwill was not evaluated for impairment during the six months ended June 30, 2012.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset’s carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of Hydro One’s long-lived assets are generally included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the return are recovered through approved revenue requirements. As a result, such assets would only generally be tested for impairment in the event that the OEB disallowed recovery in whole or in part or if such a disallowance was judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management’s intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at June 30, 2012, no asset impairment had been recorded for assets within either the Company’s regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents them as deferred debt costs on the Consolidated Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included in the Consolidated Statements of Operations and Comprehensive Income within financing charges. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the change in fair value on existing cash flow hedges to the extent that the hedge is effective.

In 2011, the FASB issued authoritative guidance to clarify that an entity has the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. This update eliminates the option to present the components of OCI as part of the statement of changes in shareholders' equity. The amendments in this update do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. These amendments are effective for reporting periods beginning after December 15, 2011 with retrospective application.

Hydro One has elected to present OCI and net income in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 8.

Short-term investments have an original maturity of three months or less. Short-term investments are generally classified as held-to-maturity. However, the Company may classify pools of short-term investments as held-for-trading where there is no intention to hold a pool of assets to maturity. Documentation of the short-term investment classification is made on inception. As at June 30, 2012 and December 31, 2011, all short-term investments were classified as held-to-maturity.

The Company’s long-term investment in Province of Ontario Floating-Rate Notes, which is held as an alternate form of liquidity to supplement the bank credit facilities, is classified as held-for-trading and is measured at fair value.

Transaction costs associated with financial assets and liabilities that are measured at fair value are recognized immediately in results of operations.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedge relationships.

The accounting guidance for derivatives requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value in the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivatives as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized in its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss is reported as a component of accumulated OCI (AOCI) and reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivatives are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship, the Company formally documents the hedging relationship between the hedged item and the hedging instrument, its risk management objective for establishing the hedging relationship, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit programs are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment funds are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset in the Consolidated Balance Sheets. For Hydro One, the post-retirement and post-employment benefit plans are unfunded because there are no related investments in plan assets.

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for pension, post-retirement and post-employment plans. The regulatory asset for the net underfunded projected benefit obligation for pension, post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension, post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The pension, post-retirement and post-employment regulatory assets are remeasured at the end of each reporting period based on the current status of the respective plans.

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act (Ontario).* Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values at the end of each reporting period.

Employee future benefits other than pension, including post-retirement and post-employment benefits, are recognized on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period. All actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan.

Employee future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks participate in the Ontario Municipal Employees Retirement System Fund (OMERS Plan), a multiemployer public sector pension fund. On September 21, 2011, the FASB issued ASU 2011-09, *Disclosures About an Employer's Participation in a Multiemployer Benefit Plan* which discusses the quantitative and qualitative disclosures an employer is required to provide about its participation in significant multiemployer plans that offer pension, post-retirement and post-employment benefits. The ASU's objective is to enhance the transparency of disclosures about the significant multiemployer plans in which an employer participates, the level of the employer's participation in those plans, the financial health of the plans, and the nature of the employer's commitments to the plans. The ASU does not change the recognition and measurement guidance for an employer's participation in a multiemployer plan.

The ASU requires employers to disclose a narrative description of the nature of the multiemployer pension plans and information about the employer's participation in the plans including the plan's legal name and details about the contributions made. An employer that is not able to provide some of the quantitative information required by the ASU must disclose what information has been omitted and why it could not obtain the information. The revised standard is effective for fiscal years beginning after December 15, 2011.

Detailed disclosures on the Company's multiemployer plan are provided in Note 9 - Retirement Benefits.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement transaction could also change the estimated liability.

Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company's AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs.* The ASU is the result of joint efforts by the FASB and the International Accounting Standards Board to develop common, converged fair value guidance on how to measure fair value and on what disclosures to provide about fair value measurements. The ASU is largely consistent with existing US GAAP fair value measurement principles under ASC 820. However, the ASU expands the existing disclosure requirements for fair value measurements, particularly of Level 3 inputs, and requires categorization by level of the fair value hierarchy for items that are not measured at fair value on the Consolidated Balance Sheets but for which the fair value is required to be disclosed. The ASU is effective for interim and annual periods beginning after December 15, 2011, for public entities. Required disclosures have been included in Note 8. As this accounting standard only requires enhanced disclosure, the adoption of this standard did not have a significant impact on the Company's financial statements.

In December 2011, the FASB issued ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*. This newly issued accounting standard requires an entity to disclose both gross and net information about instruments and transactions eligible for offset in the Consolidated Balance Sheets as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not anticipated to have a significant impact on the Company's financial position or results of operations.

4. FINANCING CHARGES

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Interest on long-term debt	106	102	210	204
Other	3	2	3	3
Less: Interest capitalized on construction and development in progress	(15)	(15)	(32)	(29)
Gain on interest-rate swap agreements	(3)	(3)	(6)	(7)
Interest earned on investments	(1)	-	(2)	(1)
	90	86	173	170

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

Current PILs represent the amounts to be remitted to the OEFC. At June 30, 2012, an outstanding balance of $3 million due from the OEFC was included in accounts receivable in the Consolidated Balance Sheets (December 31, 2011 – payable of $85 million included in accrued liabilities). The total provision for PILs includes deferred income taxes that are not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

For the six months ended June 30, 2012, the Company's overall effective tax rate of 12.87% differed from the enacted statutory rate of 26.50% primarily due to higher deductible temporary differences included in the rate-setting process, such as capital cost allowance in excess of depreciation, deductions for pension payments made in excess of amounts expensed, and interest deducted for tax purposes in excess of interest expensed for accounting purposes.

The Deferred income tax assets and liabilities as at December 31, 2011 consisted of the following:

December 31 (Canadian dollars in millions)	**2011**
Deferred income tax assets	
Depreciation and amortization in excess of capital cost allowance	6
Employee future benefits other than pension expense in excess of cash payments	5
Environmental expenditures	5
Other	1
Total deferred income tax assets	17
Less: current portion	-
	17
Deferred income tax liabilities	
Capital cost allowance in excess of depreciation and amortization	(1,106)
Employee future benefits other than pension expense in excess of cash payments	356
Environmental expenditures	61
Transmission and distribution amounts received but not recognized for accounting purposes	(46)
Goodwill	(18)
Retail settlement variance accounts	10
Other	4
Total deferred income tax liabilities	(739)
Less: current portion	19
	(758)

6. ACCOUNTS RECEIVABLE

(Canadian dollars in millions)	**June 30, 2012**	**December 31, 2011**
Accounts receivable – billed	290	268
Accounts receivable – unbilled	688	711
Accounts receivable, gross	978	979
Allowance for doubtful accounts	(20)	(18)
Accounts receivable, net	958	961

The following table shows the movements in the allowance for doubtful accounts for the six month period ended June 30, 2012 and for the year ended December 31, 2011.

(Canadian dollars in millions)	
Allowance for doubtful accounts - January 1, 2012	(18)
Write-offs	7
Additions to allowance	(9)
Allowance for doubtful accounts – June 30, 2012	(20)

(Canadian dollars in millions)	
Allowance for doubtful accounts - January 1, 2011	(25)
Write-offs	30
Additions to allowance	(23)
Allowance for doubtful accounts - December 31, 2011	(18)

7. DEBT AND CREDIT AGREEMENTS

Issuance of Short-Term Notes

Hydro One meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under its credit facility. Short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days.

Hydro One had no commercial paper borrowings outstanding as at June 30, 2012 or December 31, 2011:

(Canadian dollars in millions)	Maximum Program Size	Outstanding Commercial Paper	Average Interest Rate
June 30, 2012	1,000	-	-
December 31, 2011	1,000	-	-

Issuances of Long-Term Debt

On January 13, 2012, Hydro One issued $300 million notes under its Medium-Term Note (MTN) Program with a maturity date of January 13, 2022 and a coupon rate of 3.20%.

On May 22, 2012, Hydro One issued $300 million notes under its MTN Program with a maturity date of January 13, 2022 and a coupon rate of 3.20%. These notes were an additional offering of notes originally issued on January 13, 2012 for $300 million. This additional issuance brings the total amount outstanding for this issue to $600 million.

On May 22, 2012, Hydro One issued $125 million notes under its MTN Program with a maturity date of December 22, 2051 and a coupon rate of 4.00%. These notes were an additional offering of notes originally issued on December 22, 2011 for $100 million. This additional issuance brings the total amount outstanding for this issue to $225 million.

Credit Agreements

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks maturing in June 2017. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company may use the credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. The obligation of each lender to make any credit extension to the Company under its credit facilities is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

In addition, the Company holds a long-term investment in $250 million of Province of Ontario Floating-Rate Notes as an alternative source of liquidity.

8. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non−Derivative Financial Assets and Liabilities

As at June 30, 2012 and December 31, 2011, the Company's carrying amounts of accounts receivable, short-term investments, bank indebtedness, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt as at June 30, 2012 and December 31, 2011 are as follows:

(Canadian dollars in millions)	**June 30, 2012**		**December 31, 2011**	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt				
$500 million of MTN Series 19 Note[1]	516	516	521	521
$250 million of MTN Series 21 Note[2]	260	260	262	262
Other notes and debentures[3]	7,950	9,428	7,225	8,615
	8,726	10,204	8,008	9,398

[1] The fair value of $500 million of the MTN Series 19 Note subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $250 million of the MTN Series 21 Note subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of the MTN Series 19 Note and the MTN Series 21 Note that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivatives

As at June 30, 2012, the Company had interest-rate swaps totaling $750 million that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure is equal to about 9% of its total long-term debt of $8,726 million. The Company has the following interest-rate swaps designated as fair value hedges:

(a) two $250 million fixed-to-floating interest-rate swap agreements to convert $500 million of the $750 million MTN Series 19 Note maturing November 19, 2014 into three-month variable rate debt; and

(b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 Note maturing September 11, 2015 into three-month variable rate debt.

The Company also has interest-rate swaps totaling $550 million that are classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) two $250 million floating-to-fixed interest-rate swap agreements that lock in the floating-rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 12, 2011 to December 11, 2012 and February 21, 2012 to February 19, 2013, respectively; and

(d) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating-rate the Company pays on the $50 million floating-rate notes from January 24, 2012 to January 24, 2013.

As at June 30, 2012 and December 31, 2011, the Company's carrying amounts of derivative instruments are representative of fair value.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at June 30, 2012 and December 31, 2011 are as follows:

June 30, 2012 (Canadian dollars in millions)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	425	425	-	425	-
Long-term investment	250	250	-	250	-
Derivative instruments					
Fair value hedges – interest-rate swaps	26	26	-	26	-
Undesignated contracts – interest-rate swaps	1	1	-	1	-
	702	702	-	702	-
Liabilities:					
Bank indebtedness	23	23	23	-	-
Long-term debt	8,726	10,204	-	10,204	-
	8,749	10,227	23	10,204	-

December 31, 2011 (Canadian dollars in millions)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	228	228	-	228	-
Long-term investment	250	250	-	250	-
Derivative instruments					
Fair value hedges – interest-rate swaps	33	33	-	33	-
Undesignated contracts – interest-rate swaps	1	1	-	1	-
	512	512	-	512	-
Liabilities:					
Bank indebtedness	39	39	39	-	-
Long-term debt	8,008	9,398	-	9,398	-
	8,047	9,437	39	9,398	-

The short-term investments represent investments with an original maturity of three months or less. Short-term investments are measured at inputs other than quoted prices that are observable for the assets and are classified as Level 2.

The long-term investment represents $250 million (2011 - $250 million) of Province of Ontario Floating-Rate Notes. The notes are measured at inputs other than quoted prices that are observable for the asset and are classified as Level 2, with unrecognized gains or losses recognized in financing charges.

The derivative instruments representing interest-rate swaps are measured using other than quoted prices that are observable for these assets and are classified as Level 2.

There were no significant transfers between any of the levels during the three and six months ended June 30, 2012 and year ended December 31, 2011.

See Note 9 for further information regarding the fair value and related valuation techniques for pension plan assets.

Risk Management

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. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's transmission and distribution businesses is derived using a formulaic approach that is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce the Transmission Business' results of operations by approximately $18 million and Hydro One Networks' Distribution Business' results of operations by approximately $10 million.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivatives to lock in interest rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were outstanding as at June 30, 2012 or December 31, 2011.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the three and six months ended June 30, 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest rate swaps for the three and six months ended June 30, 2012 and 2011 are included in financing charges as follows:

	Three months ended June 30		**Six months ended June 30**	
(Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Unrealized loss (gain) on hedged debt	2	12	(7)	4
Unrealized loss (gain) on fair value interest-rate swaps	(2)	(12)	7	(4)
Net unrealized loss (gain)	-	-	-	-

At June 30, 2012 and December 31, 2011, Hydro One had $750 million of notional amounts of fair value hedges outstanding related to interest rate swaps, with assets at fair value of $26 million and $33 million, respectively. During the three and six months ended June 30, 2012 and 2011, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. As at June 30, 2012 or December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at June 30, 2012 or December 31, 2011, there was no significant accounts receivable balance due from any single customer.

At June 30, 2012, the Company's provision for bad debts was $20 million (December 31, 2011 - $18 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience.

As at June 30, 2012, approximately 3% of the Company's accounts receivable were aged more than 60 days (December 31, 2011 – 3%).

Hydro One manages its counterparty 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. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At June 30, 2012, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $29 million (December 31, 2011 - $36 million). At June 30, 2012, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties. The credit exposure of each of the four counterparties accounted for more than 10% of the total credit exposure.

9. RETIREMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment plans. The defined benefit pension plan (the Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks. Employees of Hydro One Brampton Networks participate in the OMERS Plan, a multiemployer public sector pension fund. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada).

The OMERS Plan

The OMERS plan provides fixed, monthly retirement payments on the basis of the credits earned by the participating employees. The OMERS plan is a defined contribution plan that provides pensions based on an employee's length of service and salary. The OMERS Plan participating employees and the Company contribute to the OMERS Plan. The OMERS plan had approximately 419,000 members at December 31, 2011. Hydro One Brampton Networks had 277 members in the OMERS plan at December 31, 2011.

Current contributions by Hydro One Brampton Networks are recognized as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income. Contributions for the three and six months ended June 30, 2012 were about $380 thousand and $770 thousand, respectively (2011 - $330 thousand and $650 thousand, respectively). Contributions payable at June 30, 2012 and included in accrued liabilities on the Consolidated Balance Sheets amounted to about $145 thousand (December 31, 2011 - $150 thousand).

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligations, the fair value of plan assets or the related current service cost. The OMERS plan assets are pooled together to provide benefits to employees of other plan participants and the plan assets are not segregated in separate accounts for each member entity. The OMERS plan financial statements at December 31, 2011 show an unfunded liability of $10,063 million. This unfunded liability will likely result in future payments by participating employers and employees. The total contributions of all participating employers and employees were $2,813 million for the year ended December 31, 2011. The Company's and employees' future contributions may be increased substantially if other entities withdraw from the plan. The OMERS Plan financial statements indicate that the plan was funded at 81.7% at December 31, 2011.

Pension Plan, Post-Retirement and Post-Employment Plans

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Company and employees' contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Estimated 2012 annual Pension Plan contributions of $163 million were paid during the six months ended June 30, 2012, based on an actuarial valuation effective December 31, 2011 and the expected level of 2012 pensionable earnings, resulting in a prepaid pension contributions asset of $83 million at June 30, 2012.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, the supplementary pension plan, post-retirement and post-employment plans (the Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans will be December 31, 2012 for the current year. The last measurement date was December 31, 2011.

(Canadian dollars in millions)	Pension Benefits	Post-retirement and Post-employment Benefits
Change in accrued benefit obligation		
Accrued benefit obligation, January 1, 2011	4,996	1,178
Current service cost	108	30
Interest cost	286	68
Reciprocal transfers	4	-
Benefits paid	(289)	(42)
Net actuarial loss (gain)	356	(28)
Accrued benefit obligation, December 31, 2011	5,461	1,206
Change in plan assets		
Fair value of plan assets, January 1, 2011	4,699	-
Actual return on plan assets	102	-
Reciprocal transfers	4	-
Benefits paid	(289)	-
Employer's contributions[1]	153	-
Employees' contributions	27	-
Administrative expenses	(14)	-
Fair value of plan assets, December 31, 2011	4,682	-
Unfunded status (accrued benefit obligation less fair value of plan assets)	779	1,206

[1] In January 2012, the Company made a contribution of $12 million in respect of 2011.

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

December 31, 2011 (Canadian dollars in millions)	Pension Benefits	Post-retirement and Post-employment Benefits
Accrued liabilities	-	43
Pension benefit liability	779	-
Post-retirement and post-employment benefit liability	-	1,163
Unfunded status (accrued benefit obligation less plan assets)	779	1,206

The funded/unfunded status of the pension, post-retirement and post-employment benefit obligations refers to the difference between plan assets and estimated obligations under the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan.

December 31, 2011 (Canadian dollars in millions)	
Projected benefit obligation	5,461
Accumulated benefit obligation	5,038
Fair value of plan assets	4,682

On an ABO basis, the plans were funded at 93% at December 31, 2011. On a PBO basis, the plans were funded at 86% at December 31, 2011. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following tables provide the components of the net periodic benefit costs for the three and six months ended June 30, 2012 and 2011 for all plans combined.

	Pension Benefits		Post-retirement and Post-employment Benefits	
Three months ended June 30 (Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Current service cost, net of employee contributions	24	20	7	7
Interest cost	71	71	16	17
Expected return on plan assets net of expenses[3]	(72)	(73)	-	-
Actuarial loss amortization	28	17	1	2
Prior service cost amortization	1	1	1	1
Net Periodic Benefit Cost	52	36	25	27
Charged to results of operations[1]	19	26	11	16

	Pension Benefits		Post-retirement and Post-employment Benefits	
Six months ended June 30 (Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Current service cost, net of employee contributions	48	40	14	14
Interest cost	142	142	32	34
Expected return on plan assets net of expenses[3]	(144)	(146)	-	-
Actuarial loss amortization	56	34	2	4
Prior service cost amortization	2	2	2	2
Net Periodic Benefit Cost	104	72	50	54
Charged to results of operations[2]	37	48	22	32

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. In the three months ended June 30, 2012, pension costs of $40 million (June 30, 2011 - $41 million) were attributed to labour, of which $19 million (June 30, 2011 - $26 million) was

charged to operations and $21 million (June 30, 2011- $15 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

[2] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. In the six months ended June 30, 2012, pension costs of $78 million (June 30, 2011 - $78 million) were attributed to labour, of which $37 million (June 30, 2011 - $48 million) was charged to operations and $41 million (June 30, 2011- $30 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

[3] The expected long-term rate of return on Pension Plan assets is 6.25%.

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs and credits is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following tables provide the components of regulatory assets for the year ended December 31, 2011 for all plans combined.

Year ended December 31, 2011 (Canadian dollars in millions)	Pension Benefits	Post-retirement and Post-employment Benefits
Changes in plan assets and benefit obligations recognized in regulatory assets:		
Actuarial loss (gain) for the year	558	(27)
Amortization of actuarial loss to net income	(68)	(7)
Amortization of prior service credit to net income	(4)	(3)
	486	(37)

The following table provides the components of Hydro One's regulatory assets that have not been recognized as components of periodic benefit cost as of December 31, 2011 for all plans combined:

Year ended December 31, 2011 (Canadian dollars in millions)	Pension Benefits	Post-retirement and Post-employment Benefits
Prior service cost	7	7
Actuarial loss	772	116
	779	123

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Investment-Pension Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

The Pension Plan target asset allocations and weighted average asset allocations were as follows as at December 31, 2011:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	59.4
Debt securities	35.0	37.1
Other [1]	5.0	3.5
	100.0	100.0

[1] Other investments include cash and cash equivalents, pooled funds and real estate investments.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2011. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2011, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivatives by transacting only with financial institutions rated at least "A" by S&P or "A2" by Moody's Investors Service Inc. and also by utilizing exposure limits to each counterparty. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following table presents the Pension Plan assets measured and recorded at fair value on Hydro One's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2011:

December 31, 2011 (Canadian dollars in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	3	15	165	183
Cash and cash equivalents	128	-	-	128
Short-term securities	-	38	-	38
Real estate	-	-	2	2
Corporate shares - Canadian	820	-	-	820
Corporate shares - Foreign	1,820	-	-	1,820
Bonds and debentures - Canadian	-	1,675	-	1,675
Bonds and debentures - Foreign	-	1	-	1
	2,771	1,729	167	4,667

The total fair value of pension plan assets excludes $17 million of interest and dividends receivable, $8 million related to pending sales transactions and $10 million relating to accruals for pension administration expense as of December 31, 2011.

See Note 8 for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the year ended December 31, 2011. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

(Canadian dollars in millions)	
Fair value as at January 1, 2011	167
Transfers in	-
Realized and unrealized gains	18
Purchases	9
Sales and disbursements	(27)
Fair value as at December 31, 2011	167

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of hedge fund investments and private equity investments. Hedge fund investments seek to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. Hedge fund valuations are provided by the fund manager and reported using the net asset value per share (NAV) of the investments. Hydro One has the ability to redeem these investments at NAV within the near term. Since these valuations are not highly observable, hedge fund investments have been categorized as Level 3 within pooled funds.

Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investment in the holding company is valued using NAV reported by the fund manager. This investment is categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

10. PREFERRED SHARES

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. The 12,920,000 preferred shares outstanding have a redemption value of $323 million. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of Shareholder's Equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

11. DIVIDENDS

During the three months ended June 30, 2012, preferred dividends in the amount of $5 million (2011 - $5 million) and common dividends in the amount of $25 million (2011 - $37 million) were declared and paid.

During the six months ended June 30, 2012, preferred dividends in the amount of $9 million (2011 - $9 million) and common dividends in the amount of $302 million (2011 - $75 million) were declared and paid.

12. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province of Ontario. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for the three and six months ended June 30, 2012 includes $371 million (2011 - $329 million) and $726 million (2011 - $677 million), respectively, related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for the three and six months ended June 30, 2012 includes $32 million (2011 - $32 million) and $64 million (2011 - $64 million), respectively, related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for the three and six months ended June 30, 2012 includes $7 million (2011 - $7 million) and $14 million (2011 - $14 million), respectively, related to these services.

In the three and six months ended June 30, 2012, Hydro One purchased power in the amount of $518 million (2011 - $528 million) and $1,180 million (2011 - $1,201 million), respectively, from the IESO-administered electricity market; $1 million (2011 - $4 million) and $5 million (2011 - $10 million), respectively, from OPG; and $1 million (2011 - $3 million) and $3 million (2011 - $6 million), respectively, from the OEFC.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. During the three and six months ended June 30, 2012, Hydro One incurred $3 million (2011 - $2 million) and $6 million (2011 - $5 million), respectively, in OEB fees.

Hydro One has service level agreements with IESO and OPG. These services include field, engineering, logistics and telecommunications services. During the three and six months ended June 30, 2012, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $3 million (2011 - $1 million) and $5 million (2011 - $3 million), respectively, primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $1 million (2011 - $1 million) for the six months ended June 30, 2012, and insignificant for the three months ended June 30, 2012.

The OPA funds substantially all of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives, and management fees. In the three and six months ended June 30, 2012, Hydro One received $7 million (2011 - $13 million) and $19 million (2011 - $16 million), respectively, from the OPA in respect of CDM programs.

The provision for PILs and payments in lieu of property taxes were paid or payable to the OEFC, and dividends were paid or payable to the Province.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are unsecured, interest free and settled in cash. As at June 30, 2012, the Company held $250 million (December 31, 2011- $250 million) of Province of Ontario Floating-Rate Notes.

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

(Canadian dollars in millions)	**June 30, 2012**	**December 31, 2011**
Accounts receivable	169	143
	169	143
Accounts payable	(2)	(2)
Accrued liabilities	(189)	(342)
	(191)	(344)
Long-term investment	250	250

Included in accrued liabilities are amounts owing to the IESO in respect of power purchases of $144 million (December 31, 2011 - $209 million).

13. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

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

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2012**	**2011**	**2012**	**2011**
Accounts receivable decrease (increase)	36	60	3	(66)
Materials and supplies decrease (increase)	1	-	2	(1)
Prepaid pension contributions increase	(83)	-	(83)	-
Other assets (increase) decrease	(5)	-	4	(6)
Accounts payable (decrease) increase	(2)	16	(10)	(11)
Accrued liabilities (decrease) increase	(27)	2	(162)	(22)
Accrued interest (decrease) increase	(26)	(39)	9	(2)
Long-term accounts payable and other liabilities decrease	(1)	(4)	(1)	-
Post-retirement and post-employment benefit liability increase	13	17	26	34
	(94)	52	(212)	(74)

Supplementary information:				
Net interest paid	133	141	202	206
Payments in lieu of corporate income taxes	25	15	139	50

14. CONTINGENCIES

Legal Proceedings

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

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro’s businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, the Company anticipates having to pay more than the $1 million that it paid to these Indian bands and bodies in 2011. If Hydro One cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company’s results of operations if it is not able to recover them in future rate orders.

15. COMMITMENTS

Agreement with Inergi LP (Inergi)

Effective March 1, 2002, Inergi, a wholly-owned subsidiary of Cap Gemini Canada Inc., began providing services to Hydro One. On May 1, 2010, consistent with the terms of the contract, the Company extended the Master Services Agreement with Inergi for a further three-year period. This agreement will expire on February 28, 2015. As a result of this agreement, Hydro One receives from Inergi a range of services including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Inergi billings for these services have ranged between $93 million and $130 million per year and are subject to external benchmarking every three years to ensure Hydro One is receiving a defined, competitive and continuously improved price. In connection with this agreement, on March 1, 2002, the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the Inergi agreement as at June 30, 2012 are as follows: remainder of 2012 - $69 million; 2013 - $134 million; 2014 - $128 million; 2015 - $21 million; 2016 and thereafter - $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at June 30, 2012, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton Networks using parental guarantees of $325 million (December 31, 2011 - $325 million). Prudential support at June 30, 2012 was also provided on behalf of two distributors using guarantees of $660 thousand (December 31, 2011 - $660 thousand). On April 27, 2012, Hydro One's highest credit rating declined from the "Aa" category to the "A" category. Based on the new credit rating category, the Company has provided letters of credit in the amount of $10 million to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the corporate guarantee.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at June 30, 2012, Hydro One had bank letters of credit of $124 million (December 31, 2011 - $124 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases as at June 30, 2012 are as follows: remainder of 2012 - $5 million; 2013 - $10 million; 2014 - $9 million; 2015 - $4 million; 2016 - $7 million; and thereafter - $20 million.

16. 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
- Other, the operations of which primarily consist of those of the 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, 2012 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	370	974	15	1,359
Purchased power	-	640	-	640
Operation, maintenance and administration	102	156	20	278
Depreciation and amortization	77	78	3	158
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	191	100	(8)	283
Financing charges				90
Income before provision for payments in lieu of corporate income taxes				193
Capital expenditures	189	161	-	350

Three months ended June 30, 2011 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment Profit				
Revenues	337	915	16	1,268
Purchased power	-	587	-	587
Operation, maintenance and administration	104	155	16	275
Depreciation and amortization	73	75	3	151
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	160	98	(3)	255
Financing charges				86
Income before provision for payments in lieu of corporate income taxes				169
Capital expenditures	189	155	1	345

Six months ended June 30, 2012 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	731	2,065	31	2,827
Purchased power	-	1,369	-	1,369
Operation, maintenance and administration	214	296	30	540
Depreciation and amortization	152	153	5	310
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	365	247	(4)	608
Financing charges				173
Income before provision for payments in lieu of corporate income taxes				435
Capital expenditures	376	288	3	667

Six months ended June 30, 2011 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment Profit				
Revenues	688	2,008	32	2,728
Purchased power	-	1,306	-	1,306
Operation, maintenance and administration	210	297	30	537
Depreciation and amortization	145	145	5	295
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	333	260	(3)	590
Financing charges				170
Income before provision for payments in lieu of corporate income taxes				420
Capital expenditures	361	278	1	640

(Canadian dollars in millions)	June 30, 2012	December 31, 2011
Total assets		
Transmission	10,606	10,589
Distribution	7,349	7,594
Other	1,705	653
	19,660	18,836

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

17. TRANSITION TO US GAAP

The adoption of US GAAP has been made on a retrospective basis with restatement of comparative information to reflect US GAAP requirements in effect at that time. For 2012 interim reporting purposes, the transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Company's 2012 unaudited interim Consolidated Financial Statements.

Measurement and classification differences arising out of the Company's adoption of US GAAP are presented below. With respect to measurement and classification differences, the tables under the heading US GAAP Differences, represent quantitative reconciliations of the Consolidated Balance Sheets and the Consolidated Statements of Changes in Shareholder's Equity previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP. Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholder's Equity reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. There were no measurement or classification differences arising out of the Company's adoption of US GAAP on the Consolidated Statements of Operations and Comprehensive Income.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

The following table summarizes the increases (decreases) to total assets:

(Canadian dollars in millions)	Notes	January 1, 2011	December 31, 2011
Total assets – Canadian GAAP		17,322	18,368
Deferred debt costs	A	32	32
Deferred pension asset	B	(460)	(466)
Regulatory assets	B	450	902
Total assets - US GAAP		17,344	18,836

The following table summarizes the increases (decreases) to total liabilities:

(Canadian dollars in millions)	Notes	January 1, 2011	December 31, 2011
Total liabilities – Canadian GAAP		11,341	11,914
Long-term debt	A	5	9
Net unamortized debt premiums	A	27	23
Pension benefit liability	B	297	779
Post-retirement and post-employment benefit liability	B	153	123
Regulatory liabilities	B	(460)	(466)
Total liabilities - US GAAP		11,363	12,382

US GAAP Differences

The reconciliations of the January 1, 2011 and December 31, 2011 Consolidated Balance Sheets from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (Canadian dollars in millions)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Cash		33	-	33
Short-term investments		139	-	139
Accounts receivable		911	-	911
Regulatory assets		42	-	42
Materials and supplies		21	-	21
Deferred income tax assets		35	-	35
Derivative instruments	C	-	1	1
Other	C	8	(1)	7
		1,189	-	1,189
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		12,520	-	12,520
Construction in progress		1,402	-	1,402
Future use land, components and spares		139	-	139
		14,061	-	14,061
Other long-term assets:				
Regulatory assets	B	1,013	450	1,463
Deferred pension asset	B	460	(460)	-
Long-term investment		249	-	249
Intangible assets (net of accumulated amortization)		189	-	189
Goodwill		133	-	133
Deferred debt costs	A	-	32	32
Derivative instruments	C	-	7	7
Deferred income tax assets		19	-	19
Other	C	9	(7)	2
		2,072	22	2,094
Total assets		17,322	22	17,344

January 1, 2011 (Canadian dollars in millions)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D	884	(884)	-
Accounts payable	D	-	125	125
Accrued liabilities	D	-	759	759
Accrued interest		84	-	84
Regulatory liabilities		72	-	72
Long-term debt payable within one year		500	-	500
		1,540	-	1,540
Long-term debt	A	7,278	5	7,283
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	980	153	1,133
Deferred income tax liabilities		693	-	693
Pension benefit liability	B	-	297	297
Environmental liabilities		287	-	287
Regulatory liabilities	B	540	(460)	80
Net unamortized debt premiums	A	-	27	27
Asset retirement obligations		11	-	11
Long-term accounts payable and other liabilities		12	-	12
		2,523	17	2,540
Total liabilities		11,341	22	11,363
Preferred shares (authorized: unlimited; issued: 12,920,000)	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares (authorized: unlimited; issued: 100,000)		3,314	-	3,314
Retained earnings		2,354	-	2,354
Accumulated other comprehensive loss		(10)	-	(10)
Total shareholder's equity		5,981	(323)	5,658
Total liabilities, preferred shares and shareholder's equity		17,322	22	17,344

December 31, 2011 (Canadian dollars in millions)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Short-term investments		228	-	228
Accounts receivable		961	-	961
Regulatory assets		24	-	24
Materials and supplies		25	-	25
Deferred income tax assets		19	-	19
Derivative instruments	C	-	1	1
Other	C	20	(1)	19
		1,277	-	1,277
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		13,329	-	13,329
Construction in progress		1,436	-	1,436
Future use land, components and spares		138	-	138
		14,903	-	14,903
Other long-term assets:				
Regulatory assets	B	1,064	902	1,966
Deferred pension asset	B	466	(466)	-
Long-term investment		250	-	250
Intangible assets (net of accumulated amortization)		224	-	224
Goodwill		133	-	133
Deferred debt costs	A	-	32	32
Derivative instruments	C	-	33	33
Deferred income tax assets		17	-	17
Other	C	34	(33)	1
		2,188	468	2,656
Total assets		18,368	468	18,836

December 31, 2011 (Canadian dollars in millions)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Bank indebtedness		39	-	39
Accounts payable and accrued charges	D	1,071	(1,071)	-
Accounts payable	D	-	154	154
Accrued liabilities	D	-	917	917
Accrued interest		85	-	85
Regulatory liabilities		25	-	25
Long-term debt payable within one year		600	-	600
		1,820	-	1,820
Long-term debt	A	7,399	9	7,408
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	1,040	123	1,163
Deferred income tax liabilities		758	-	758
Pension benefit liability	B	-	779	779
Environmental liabilities		235	-	235
Regulatory liabilities	B	635	(466)	169
Net unamortized debt premiums	A	-	23	23
Asset retirement obligations		15	-	15
Long-term accounts payable and other liabilities		12	-	12
		2,695	459	3,154
Total liabilities		11,914	468	12,382
Preferred shares (authorized: unlimited; issued: 12,920,000)	E	-	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	-
Common shares (authorized: unlimited; issued: 100,000)		3,314	-	3,314
Retained earnings		2,827	-	2,827
Accumulated other comprehensive loss		(10)	-	(10)
Total shareholder's equity		6,454	(323)	6,131
Total liabilities, preferred shares and shareholder's equity		18,368	468	18,836

The adjustments to the January 1, 2011 and December 31, 2011 equity from Canadian GAAP to US GAAP are as follows:

January 1, 2011 *(Canadian dollars in millions)*	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,354	5,981
Other comprehensive income	-	-	-	-	-
Preferred shares reclassed outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,354	5,658

December 31, 2011 *(Canadian dollars in millions)*	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,827	6,454
Other comprehensive income	-	-	-	-	-
Preferred shares reclassed outside shareholder's equity	-	(323)	-	-	(323)
US GAAP	3,314	-	(10)	2,827	6,131

Notes to the Transitional Adjustments

Under US GAAP, the Company (i) measures certain assets and liabilities differently than it had under Canadian GAAP (see details on each measurement change below); and (ii) discloses certain assets, liabilities and equity on different lines in the Consolidated Financial Statements than it had under Canadian GAAP (see details on each classification change below).

A. Debt Issuance Costs (classification change)

Under Canadian GAAP, costs of arranging debt financing, premiums and discounts were netted against long-term debt. Under US GAAP, costs of arranging debt financing are included in "Deferred debt costs" as part of "Other long-term assets", and net unamortized premiums are included in "Net unamortized debt premiums" as part of "Other long-term liabilities".

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases:

(Canadian dollars in millions)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred debt costs	32	32
Other long-term liabilities:		
Net unamortized debt premiums	27	23
Long-term debt	5	9

B. Pension, Post-Retirement and Post-Employment Benefits (measurement change)

Under Canadian GAAP, the Company disclosed, but was not required to recognize, the net unfunded status of pension, post-retirement and post-employment benefits obligations on the Consolidated Balance Sheets. Under US GAAP, the Company recognized the unfunded status of pension, post-retirement and post-employment obligations on the Consolidated Balance Sheets with an offset to associated regulatory assets for the transitional fair value adjustments as the incremental obligations are expected to be recovered through future rates charged to customers. The deferred tax assets and liabilities arising on recognition of incremental pension, post-retirement and post-employment obligations and the associated regulatory assets offset each other, with no material impact on the Consolidated Statements of Operations and Comprehensive Income. In the absence of regulatory accounting, the related tax impact on the opening transitional adjustments would result in the recognition of deferred tax assets of $113 million on January 1, 2011 and $224 million on December 31, 2011, respectively.

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(Canadian dollars in millions)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred pension asset	(460)	(466)
Regulatory assets [1]	450	902
Other long-term liabilities:		
Pension benefit liability	297	779
Post-retirement and post-employment benefit liability	153	123
Regulatory liabilities [2]	(460)	(466)

[1] Represents off-setting regulatory assets for incremental obligation for pension and non-pension obligations of $297 million and $153 million on January 1, 2011, and $779 million and $123 million on December 31, 2011, respectively.

[2] Represents write-off of deferred pension asset regulatory liability under Canadian GAAP.

C. Derivatives (classification change)

Under Canadian GAAP, the Company classified its derivatives in designated hedging relationships and in economic hedging relationships under the category of “Other assets” on the Consolidated Balance Sheets. Under US GAAP, the Company has included these balances in “Derivative instruments”.

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(Canadian dollars in millions)	**January 1, 2011**	**December 31, 2011**
Current assets:		
Derivative instruments	1	1
Other	(1)	(1)
Other long-term assets:		
Derivative instruments	7	33
Other	(7)	(33)

D. Accounts Payable (classification change)

Under Canadian GAAP, trade and non-trade payables were disclosed as “Accounts payable and accrued charges”. Under US GAAP, trade payables are recognized in “Accounts payable” and non-trade payables are recognized in “Accrued liabilities”.

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(Canadian dollars in millions)	**January 1, 2011**	**December 31, 2011**
Current liabilities:		
Accounts payable	125	154
Accrued liabilities	759	917
Accounts payable and accrued charges	(884)	(1,071)

E. Preferred Shares (classification change)

Under Canadian GAAP, Hydro One’s preferred shares were classified as equity and preferred dividends were deducted from retained earnings and were accrued as declared. Under US GAAP, the preferred shares are classified outside shareholder’s equity because of conditional redemption features in the preferred share agreement. Under US GAAP, the preferred dividends continue to be deducted from retained earnings and are accrued as declared (refer to Note 10).

As at January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(Canadian dollars in millions)	**January 1, 2011**	**December 31, 2011**
Preferred shares	323	323
Shareholder’s equity:		
Preferred shares	(323)	(323)

18. SUBSEQUENT EVENT

On July 31, 2012, Hydro One issued $75 million notes under its MTN Program with a maturity date of July 31, 2062 and a coupon rate of 3.79%.

19. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2012 unaudited interim Consolidated Financial Statements.