## 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 months ended March 31, 2012 to the three months ended March 31, 2011. On January 1, 2012, Hydro One Inc. adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting.

### Revenues

| *Three months ended March 31 (Canadian dollars in millions)* | **2012** | **2011** | **$ Change** | **% Change** |
|---|---|---|---|---|
| Transmission | 361 | 351 | 10 | 3 |
| Distribution | 1,091 | 1,093 | (2) | - |
| Other | 16 | 16 | - | - |
| | 1,468 | 1,460 | 8 | 1 |
| Average Ontario 60- minute peak demand (MW) [1] | 20,712 | 21,757 | (1,045) | (5) |
| Distribution - units distributed to customers (TWh) [1] | 7.8 | 8.3 | (0.5) | (6) |

[1] System-related statistics are preliminary

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

#### *Transmission*

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include 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 $10 million, or 3%, compared to the same period 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 that approved the use of US GAAP as the approved basis for setting rates within our Transmission Business. In that decision, the OEB also approved adjustments to our previously approved 2012 transmission revenue requirement, capital expenditure levels and rate base consistent with those we proposed in our evidence. On December 20, 2011, effective January 1, 2012, the OEB approved new transmission tariff rates for 2012 that 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 revenues of $26 million.

Our increased transmission tariff revenues were partially offset by a lower average monthly peak demand experienced during the first quarter of 2012. The average Ontario 60-minute peak demand was 1,045 MW lower than in the same period last year, resulting in lower revenues of $14 million. This reduction in demand was attributable to generally milder weather over the winter months compared to the same period last year. We also experienced lower transmission revenues of $2 million compared to last year following the completion of our recovery of a transmission regulatory account effective December 31, 2011.

#### *Distribution*

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by our customers. 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 decreased by $2 million in the first quarter of 2012 compared to the same period last year. Lower energy consumption contributed to a reduction in our distribution revenues of $17 million, primarily as a result of the milder winter experienced this year. This reduction in our distribution revenues was partially offset by increased recovery of higher purchased power costs of $10 million, as described below in the section “Purchased Power.” In addition, we earned increased distribution revenues of $5 million compared to the prior year related to our placement in-service of new smart grid and smart meter investments, which are currently recovered through separate rate mechanisms.

**Purchased Power**

Purchased power costs incurred by our Distribution Business 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 May 1, 2010 and substantially all 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 |

| **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 |

Purchased power costs increased in 2012 by $10 million, or 1%, to $729 million compared to the same period in 2011. This increase was primarily due to the impact of changes in the OEB’s RPP rates for residential and other eligible customers of $36 million, higher purchased power costs of $10 million for customers who are ineligible for the RPP and increased transmission charges of $9 million following from the OEB’s transmission rate decisions that were effective January 1, 2012. The effect of these increases was partially offset by a lower demand for electricity that reduced our year-over-year purchased power costs by $41 million and a $4 million reduction in wholesale market service charges levied by the IESO compared to the same quarter last year.

**Operation, Maintenance and Administration**

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

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

| *Three months ended March 31 (Canadian dollars in millions)* | **2012** | **2011** | **$ Change** | **% Change** |
|---|---|---|---|---|
| Transmission | 112 | 106 | 6 | 6 |
| Distribution | 140 | 142 | (2) | (1) |
| Other | 10 | 14 | (4) | (29) |
| | 262 | 262 | - | - |

***Transmission***

Transmission operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $6 million, or 6%, in 2012 compared to the same period last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program requirements were higher by $2 million compared to last year. In the quarter, we incurred expenditures of $7 million 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"). The impact of these expenditures was partially offset by lower requirements by our Transformer Midlife Refurbishment Program following the accelerated completion of critical transformer work last year, lower levels of station-related corrective maintenance, particularly for power equipment, and recoveries associated with an insurance settlement. In addition, we experienced lower requirements in the quarter related to our environmental on-site oil leak reduction program. Our expenditures in support of our transmission system have increased by $4 million, primarily reflecting higher information technology expenditures.

***Distribution***

Distribution operation, maintenance and administration expenditures required to maintain our low-voltage distribution system decreased by $2 million, or 1%, compared to the comparable period. Our work program expenditures increased by $1 million, primarily as the result of increased power restoration expenditures consistent with a higher volume of trouble calls and storm activity during the quarter. We also experienced increased year-over-year forestry program expenditures as we took advantage of favourable weather conditions. These increases were partially offset by lower planned line corrective maintenance requirements given our smaller program this year. Our expenditures in support of our distribution system decreased by $3 million, reflecting a redirection of resources in support of our Transmission Business, partly offset by higher information technology expenses and investments supporting our Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project.

**Depreciation and Amortization**

Depreciation and amortization expense increased by $8 million, or 6%, to $152 million in the first quarter compared to the same period last year. This increase was attributable to higher depreciation of approximately $9 million resulting from our placement of new assets in service, consistent with our ongoing capital work program. This was partially offset by a reduction of $1 million in the amortization of our regulatory and other assets.

**Financing Charges**

Financing charges of $83 million decreased slightly by $1 million, or 1%, compared to the first quarter of 2011. The decrease resulted from higher interest capitalized of $4 million reflecting higher interest capitalization rates used on construction in progress, offset by a $3 million increase in long-term debt interest expense primarily as a result of an increased average level of debt, partially offset by a lower average effective interest rate.

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

The provision for payments in lieu of corporate income taxes decreased by $7 million, or 18%, to $32 million compared to 2011. This decrease was a result of a reduction in the statutory tax rate from 28.25% to 26.25% effective January 1, 2012, lower levels of pre-tax income compared to the comparative period in the prior year, as well as a small change to net temporary differences.

**Net Income**

Net income of $210 million for the quarter was slightly lower than our comparable 2011 results by $2 million, or 1%. During the first quarter of 2012, our net revenues were impacted by unseasonably warm weather resulting in decreased transmission peak demands and lower distribution consumption. In addition, our net income reflects higher depreciation and amortization costs resulting from our placement of new assets in service consistent with our increased capital work program. These impacts were partially offset by new OEB-approved Uniform Transmission Rates effective January 1, 2012 that will support our aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and investments in support of the Green Energy Act. Our net income was also positively impacted by a lower statutory income tax rate that became effective January 1, 2012.

## QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from June 30, 2010 through March 31, 2012. This information has been derived from our unaudited interim 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* | **Mar. 31** | **Dec. 31** | **Sep. 30** | **Jun. 30** | **Mar. 31** | **Dec. 31**[2] | **Sep. 30**[2] | **Jun. 30**[2] |
| Total revenue[1] | 1,468 | 1,359 | 1,384 | 1,268 | 1,460 | 1,280 | 1,360 | 1,165 |
| Net income[1] | 210 | 120 | 167 | 142 | 212 | 99 | 218 | 105 |
| Net income to common shareholder[1] | 206 | 115 | 163 | 137 | 208 | 94 | 214 | 100 |

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

[2] 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, investing activities, and dividends.

### Summary of Sources and Uses of Cash

| *Three months ended March 31 (Canadian dollars in millions)* | 2012 | 2011 |
|---|---|---|
| **Operating activities** | 237 | 240 |
| **Financing activities** | | |
| Long-term debt issued | 300 | 300 |
| Long-term debt retired | - | (250) |
| Dividends paid | (281) | (42) |
| **Investing activities** | | |
| Capital expenditures | (317) | (295) |
| **Other financing and investing activities** | 1 | 3 |
| **Net change in cash and cash equivalents** | (60) | (44) |

### Operating Activities

Net cash from operating activities decreased by $3 million, or 1%, to $237 million compared to the same period last year. The decrease primarily reflects reductions in taxes payable, resulting from a payment made in the first quarter of 2012 related to the 2011 taxation year, and changes in certain regulatory account balances. These reductions were largely offset by changes in accounts receivable balances compared to the same period last year in line with changes in revenue in the same periods, and to improved accounts receivable collection cycles.

### 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 2014, 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 March 31, 2012, we had $8,275 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 March 31, 2012, $2,300 million remains 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.[2] | Prime-1 | A1 |
| S&P[1] | A-1 | A+ |

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

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 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 March 31, 2012.

In the first quarter of 2012, we successfully issued $300 million in cost-effective long-term debt under our MTN Program and no long-term debt matured in the period. In the first quarter of 2011, we issued $300 million in long-term debt under our MTN Program and repaid $250 million in maturing long-term debt. In the first quarters of 2012 and 2011, we did not issue any short-term notes and we had no short-term notes outstanding as at either March 31, 2012 or March 31, 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 first quarter of 2012, we paid dividends to the Province in the amount of $281 million, consisting of $277 million in common dividends and $4 million in preferred dividends. In the comparative period, we paid common dividends of $38 million and preferred dividends of $4 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 March 31 (Canadian dollars in millions)* | **2012** | **2011** | **$ Change** | **% Change** |
|---|---|---|---|---|
| Transmission | 187 | 172 | 15 | 9 |
| Distribution | 127 | 123 | 4 | 3 |
| Other | 3 | - | 3 | 100 |
| | 317 | 295 | 22 | 7 |

### *Transmission*

Our transmission capital expenditures increased by $15 million, or 9%, to $187 million compared to the first quarter in 2011. Expenditures to expand and reinforce our transmission system were $93 million, representing an increase of $3 million from the comparable period last year. 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 year-over-year increase in our expenditures results from our local area supply projects progressing into their build phases, investments in our transformer stations related to the Advanced Distribution System (ADS) Project, as well as increased investments related to our transmission projects and upgrades to safely and reliably accommodate additional renewable energy. The impacts of these increases were offset during the quarter by lower expenditures related to inter-area network upgrade projects that were completed in the last quarter of last year, including the installation of complex static var compensators (SVCs) at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations.

Our inter-area network projects include our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. 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. During the quarter, 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 successfully put into service on March 26, 2012.

Expenditures to sustain our existing transmission system were $82 million, representing an increase of $9 million compared to the same period in 2011. This increase was primarily related to the refurbishment and replacement of end-of-life equipment at our transformer stations in order to improve reliability. We also incurred higher expenditures related to the advancement of our wood pole replacement program.

Our other transmission capital expenditures were $12 million, representing an increase of $3 million compared to the same quarter in the prior year. The majority of these expenditures were related to fleet acquisitions and to information technology investments.

### *Distribution*

Our distribution capital expenditures increased by $4 million, or 3%, to $127 million in the first quarter of 2012, compared to the same period last year.

Capital expenditures to expand and reinforce our distribution network were $55 million, representing a reduction of $8 million compared to last year. We experienced reduced expenditures within our Smart Meter Project compared to last year as it is nearing completion. This impact was partially offset by our continued investments in our ADS Project.

Expenditures to sustain our distribution system were $45 million, representing a decrease of $2 million from the same period in 2011. Our sustainment program was impacted by the timing of capital contributions received in respect of work for joint use and relocation of our lines. This impact was partially offset by additional requirements for emergency restoration work as a result of increased storm activity this year combined with increased work for our lines program as resources were utilized early in the year to advance the program given favourable weather conditions.

Our other distribution capital expenditures were $27 million, representing an increase of $14 million from the first quarter in 2011. This increase 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 which 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 $1.8 billion. Our 2012 capital budgets for our transmission and distribution businesses are about $1 billion and $0.8 billion respectively. Consolidated capital expenditures are also expected to be approximately $1.8 billion 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 Distributed Generation (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 budgeted 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.

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 Inc.'s (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 in the remainder of 2012. For the remaining three upgrades, alternative solutions have been identified. The overall capital cost for the stations is estimated to be up to $50 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. 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 a SVC at our Milton Switching Station to increase the transmission capability of the Bruce transmission system. We are awaiting an OPA recommendation regarding the construction of a new transmission line west of the City of London.

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 2011, we spent approximately $19 million on these projects, and in the first quarter of 2012 we spent an additional $7 million, all of which 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 will not 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.

| *March 31, 2012 (Canadian dollars in millions)* | **Total** | **2012[1]** | **2013/2014** | **2015/2016** | **After 2016** |
|---|---|---|---|---|---|
| **Contractual Obligations** *(due by year)* | | | | | |
| Long-term debt – principal repayments | 8,275 | 600 | 1,350 | 1,000 | 5,325 |
| Long-term debt – interest payments | 6,806 | 344 | 736 | 634 | 5,092 |
| Inergi LP (Inergi) outsourcing agreement[2] | 386 | 103 | 262 | 21 | - |
| Operating lease commitments | 54 | 7 | 17 | 10 | 20 |
| Environmental and asset retirement obligations[3] | 326 | 27 | 61 | 48 | 190 |
| **Total Contractual Obligations** | 15,847 | 1,081 | 2,426 | 1,713 | 10,627 |
| **Other Commercial Commitments** *(by year of expiry)* | | | | | |
| Bank line[4] | 1,250 | - | 1,250 | - | - |
| Letters of credit[5] | 125 | 124 | 1 | - | - |
| Guarantees[5] | 326 | 326 | - | - | - |
| Pension[6] | 125 | 125 | - | - | - |
| **Total Other Commercial Commitments** | 1,826 | 575 | 1,251 | - | - |

1 The amounts disclosed represent the amounts due over the period April 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 2014. On April 13, 2012, we received unanimous consent from the syndicate of banks to extend the maturity date to June 1, 2017.

5 We currently have outstanding bank letters of credit of $124 million relating to retirement compensation arrangements. 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. On April 27, 2012, our highest credit rating declined from the “Aa” category to the “A” category. Based on this credit rating category, we estimate that we will be required to provide prudential support of between $10 million and $35 million in the form of letters of credit or Government of Canada T-bills. On May 9, 2012, we provided letters of credit in the amount of approximately $14 million to meet our current requirement.

6 Contributions to the pension fund are generally made one month in arrears. Contributions for 2012 are based on an actuarial valuation filed in September 2010 and effective December 31, 2009. Our annual pension contributions for 2012 will be approximately $163 million based on the expected level of pensionable earnings. Future minimum contributions will be based on an actuarial valuation effective no later than December 31, 2012 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2012 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 in 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 within our capital expenditures.

## RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in 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 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 quarter of 2012, we contributed $38 million into our pension plan and incurred $52 million in net periodic pension benefit cost based on an actuarial valuation effective December 31, 2009 that was filed in September of 2010. Actuarial valuations are minimally required to be filed every three years. We currently estimate our annual pension contributions to be approximately $163 million in 2012 based on the projected level of pensionable earnings. Future minimum contributions will be based on an actuarial valuation effective no later than December 31, 2012 and will depend on future investment returns, changes in benefits and actuarial assumptions. The plan experienced positive returns of about 4.7% in the first quarter of this year.

## TRANSITION TO US GAAP

### *Accounting Framework for External Reporting*

Our unaudited interim Consolidated Financial Statements and accompanying notes as at, and for the three months ended March 31, 2012 have been prepared in accordance with US GAAP. These are our first US GAAP unaudited interim Consolidated Financial Statements. 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 is disclosed in the reconciliation to US GAAP included in Note 17 to the unaudited interim Consolidated Financial Statements as at and for the three months ended March 31, 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 first quarter unaudited interim Consolidated Financial Statements. The accounting policies set out in the unaudited interim Consolidated Financial Statements for the period ended March 31, 2012 have been consistently applied to all the periods presented. The comparative figures in respect of 2011 were restated to reflect the adoption of US GAAP.

### *Accounting Framework for Rate Setting*

In 2011, we applied for and received Ontario Securities Commission (OSC) approval allowing us to adopt US GAAP as the basis for our accounting, external financial reporting and periodic securities filings. Consistent with this OSC decision, in 2011 two of our subsidiaries, Hydro One Networks and Hydro One Remote Communities (Hydro One Remotes) 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 the OEB's standard modified IFRS basis. The OEB has granted approval for Hydro One Networks' regulated distribution and transmission businesses and for Hydro One Remotes to adopt US GAAP as their approved regulatory basis for rate setting 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 Inc. (Hydro One Brampton Networks). Hydro One Brampton Networks implemented International Financial Reporting Standards (IFRS) accounting for its 2011 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*

No financial covenants were impacted by our conversion to US GAAP.

### *Internal Control over Financial Reporting and Disclosure Controls and Procedures*

Our transition to US GAAP did not have any significant impact on our internal controls over financial reporting and disclosure controls and procedures.

### *Financial Reporting Expertise*

Given the similarities between US GAAP and Canadian GAAP, there has also been no significant impact from the transition to US GAAP on our 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 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 emerging issues.

### *IT Systems*

Given the similarities between US GAAP and Canadian GAAP pertaining to our company, there has been no significant impact from the transition to US GAAP on our information technology systems.

## 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 March 31, 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

### *Ontario Electricity System Operator*

On April 26, 2012, the Government of Ontario introduced Bill 75, to be known as the Ontario Electricity System Operator Act, 2012, which will reflect the amalgamation of the OPA and the IESO. This proposed legislation will amend the Electricity Act, 1998 and the Ontario Energy Board Act, 1998 as well as make some complementary amendments in other legislation. The proposed name for the amalgamated entity is the Ontario Electricity System Operator (OESO). The functions and objects of the OPA and the IESO as presently set out in the Electricity Act, 1998 for each entity will be substantially the same in the amalgamated entity under Bill 75 with a governance structure in place to separate the functions and activities of the OESO related to market operations and procurement and contract management activities.

### *Southpoint Wind Legal Claim*

On April 4, 2012, we received a legal claim by SouthPoint Wind asserting a claim against Hydro One Networks, the OPA, three Ministries of the Provincial Government and Environment Canada for $1.2 billion. The allegations against Hydro One Networks relate to applications Southpoint Wind had made under the Renewable Energy Standard Offer Program (RESOP). All of Southpoint Wind's allegations must be considered in the context of two moratoriums imposed by the Provincial Government on offshore wind projects, which are the projects Southpoint Wind was pursuing in the RESOP and FIT programs. At this point, without further details, it is difficult to assess the factual and legal context of this claim.

***OEB Applications***

*Hydro One Remotes*

On April 3, 2012, the OEB approved Hydro One Remotes' request to adopt US GAAP as its basis for rate setting, and regulatory accounting and reporting.

*Hydro One Networks*

On March 23, 2012, the OEB approved Hydro One Networks' request to adopt US GAAP as its basis for rate setting, and regulatory accounting and reporting within its Distribution Business, consistent with an earlier approval granted to its Transmission Business.

A transmission Cost of Service rate application continues to be planned for 2013 and 2014 rates, with a proposed regulated return on equity based on the application of the OEB's cost of capital report. Regarding our Distribution Business, we have not filed for a 2012 rate adjustment and are currently considering using the OEB's Incentive Rate Mechanism for 2013 and 2014.

***Renewed Regulatory Framework for Electricity (RRFE)***

Between March 28, 2012 and March 30, 2012, the OEB hosted a stakeholder conference on the five staff discussion papers and supporting consulting reports that it released on November 8, 2011 as part of its coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. This initiative was originally launched in late 2010. The sessions followed a series of meetings in February and March 2012 between the Chair of the OEB and sector leaders to discuss the development of the RRFE at a strategic level. The three-day session covered a number of topics, which were supported by different panels and parties. Our company made presentations on regional planning and Incentive Regulation Mechanism filing alternatives. There were consistent messages expressed by participants during these meetings. Key areas of agreement included the ability to recover investments in infrastructure during Incentive Regulation Mechanism periods, the need to prioritize solutions for regional planning and consideration of implications of outcome-based regulation. Stakeholders' written comments were provided to the OEB by April 20, 2012. The OEB plans to make a policy statement in the summer of 2012.

***West of London Transmission Upgrade Project***

On March 28, 2012, Hydro One Networks filed a Section 92 leave-to-construct application with the OEB for our West of London Transmission Upgrade Project. The project is anticipated to enable the connection of approximately 500 MW of additional renewable generation in the west of London area, depending on various future conditions.

***Provincial Budget***

On March 27, 2012, the Province tabled its 2012-2013 Budget, *Strong Action for Ontario*, aimed at eliminating Ontario's deficit by 2017-2018. Included were several items aimed at reducing costs within the greater public sector, within the energy sector specifically, and on energy bills. As a result of the budget, on April 18, 2012, the Minister of Energy announced the Province's plans to merge the OPA and the IESO into a single organization, as noted above, in order to achieve cost savings and improve the effectiveness of the two organizations. Also as a result of the budget, on April 13, 2012, the Province announced that it is launching a comprehensive review of Ontario's electricity sector. The review will explore options to improve efficiencies, including opportunities for additional consolidation of local distribution companies. Another part of this review is an independent benchmarking study of electricity agencies. The Budget was passed in the Ontario Legislature on April 24, 2012.

***FIT Program Review***

On March 22, 2012, the Province announced the results of its scheduled two-year FIT Program Review (the Review). The Review reaffirmed the Province's commitment to develop clean energy in Ontario and stated that Ontario is on-track to achieve the target of 10,700 MW of non-hydroelectric renewable generation by 2015. Recommendations resulting from the Review included: creating more jobs sooner by streamlining the regulatory approvals process while maintaining the highest environmental standards; reducing FIT prices for solar by approximately 20% on average and wind prices by approximately

15%; encouraging greater community and Aboriginal participation through a new priority point system which will also prioritize projects with municipal support; reserving 10% of remaining capacity for projects with significant participation from local or Aboriginal communities; and developing a Clean Energy Economic Development Strategy to leverage Ontario's significant expertise and strengths to become a global leader in the sector. On April 5, 2012, the Province formally directed the OPA to implement the recommendations from the Review.

### *The Drummond Report*

On February 15, 2012, the Province released the report by the Commission on the Reform of Ontario's Public Services, authored by economist Don Drummond. The report, *Public Services for Ontarians: A Path to Sustainability and Excellence*, lists several recommendations that have the potential to impact the Ontario electricity distribution sector and the wider electricity industry. A key finding, among others, was the consolidation of Ontario's 80 local distribution companies along regional lines to create economies of scale.

### *Power Workers' Union (PWU) Appeal*

On February 14, 2012, a decision was issued by the Ontario Superior Court of Justice (Divisional Court) dismissing an appeal against the OEB's December 23, 2010 decision with reasons on Hydro One Networks' 2011 and 2012 transmission rate applications. This appeal was initially submitted on January 17, 2011 by the PWU. The PWU had appealed to the Divisional Court asserting that the OEB failed to permit Hydro One Networks to recover its proposed prudently incurred operation, maintenance and administration costs and therefore, that a legal error was made.

## SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

| *Three months ended March 31 (Canadian dollars in millions, except earnings per common share)* | **2012** | **2011** |
|---|---|---|
| Net income | 210 | 212 |
| Net cash from operating activities | 237 | 240 |
| Capital expenditures | 317 | 295 |
| Earnings per common share | 2,054 | 2,076 |
| Earnings coverage ratio[1] | 2.67 | 2.55 |
| Net asset coverage on long-term debt[2] | 1.77 | 1.81 |
| Total debt to capitalization[3] | 57% | 55% |

[1] The earnings coverage ratio has been presented for the twelve months ended March 31, 2012 and March 31, 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 March 31, 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 March 31, 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 related to the OEB's RRFE; statements about outstanding legal proceedings; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility including its expected interest rate; 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 liabilities and assets; 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; statements related to the expected term of our use of our facilities; expectations regarding the impact of the decline in our credit rating: statements related to Bill 75; expectations regarding the timing and conyent of applications to the OEB; expectations related to decisions from the OEB, including impacts of such decisions on an average residential customer's bill; statements regarding new accounting standards and their anticipated impacts; statements regarding the funding of the Conservation and Demand Management programs; statements relating to the strategies we may use to manage the risks related to our debt portfolio and interest rate exposure; the effect of interest rates on our results of operations; statements regarding the estimated impact of changes in the forecasted long-term Government of Canada bond yield on our results of operations; regarding future pension contributions and our pension plan and actuarial valuation; statements related to the credit risk of our counterparties; expectations regarding our exposure under our supplementary pension plan; the possibility of the Province exercising its right to redeem the preferred shares; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements about our outsourcing arrangement with Inergi; statements about critical accounting estimates; statements about US GAAP and our adoption of US GAAP, including the effects it will have on our revenue requirements; 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 May 10, 2012. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.